ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672
2943 SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPLINE, 2001-02

RECORDS CERTIFICATION

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1/22/2004
Date

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SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPLINES, 2001-2002

MEMBERS:

SENATOR JOHN TORGERSON, CHAIR
SENATOR JOHNNY ELLIS
SENATOR RICK HALFORD
SENATOR PETE KELLY
SENATOR DONALD OLSON, ALTERNATE
REPRESENTATIVE JOE GREEN, VICE-CHAIR
REPRESENTATIVE MIKE CHENAULT, ALTERNATE
REPRESENTATIVE JOHN DAVIES
REPRESENTATIVE HUGH FATE, ALTERNATE
REPRESENTATIVE REGGIE JOULE, ALTERNATE
REPRESENTATIVE SCOTT OGAN
REPRESENTATIVE BRIAN PORTER

Established by Legislative Resolve No. 32 (SCR 14), 2001.

Contents: 15 files. 38 tapes are also available of meetings held 7/17/01 - 8/19/02.

These are the personal files of committee member Sen. Rick Halford, who was also Senate President and on the Alaska Highway Natural Gas Policy Council. No other files were received from this committee.

LIST OF FILES (PAGE 1) MICROFICHE #

1. 7/17&18/01, COMMITTEE HEARING
2. 8/14&15/01, COMMITTEE HEARING - FAIRBANKS
3. 8/19&24/01, COMMITTEE HEARING - WESTERN CANADA
4. 9/19/01, COMMITTEE HEARING - ANCHORAGE
5. 10/01, COMMITTEE ACTIVITIES AND MATERIALS
6. 11/7&8/01, COMMITTEE HEARING
7. 1/02, COMMITTEE MATERIALS
8. 2/13/02, COMMITTEE MEETING
9. 2/15/02, COMMITTEE MEETING
10. 3/02, COMMITTEE ACTIVITIES

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11. 4/10/02, COMMITTEE MEETING

12. REPORT ON THE NATURAL GAS PIPELINE, COMPILED BY SENATOR JOHN TORGERSON, CHAIR, JOINT COMMITTEE ON NATURAL GAS PIPELINES, MAY 2002

13. ALASKA HIGHWAY NATURAL GAS POLICY COUNCIL

14. ALASKA HIGHWAY NATURAL GAS POLICY COUNCIL - TIMELINE, MEETING AGENDA, AND BACKUP MATERIAL

15. ALASKA HIGHWAY NATURAL GAS POLICY COUNCIL - OVERVIEW OF THE REGULATORY ENVIRONMENT, PRESENTATION BY WILLIAM BRITT, STATE PIPELINE CO-ORDINATOR, DNR (PLUS OTHER GAS PIPELINE RELATED BILLS AND MATERIALS - ALL OF WHICH HAD BEEN KEPT TOGETHER IN A BINDER. INCLUDES CD: ALASKA GAS PIPELINE MODELS, BY NORTHERN ECONOMIC RESEARCH ASSOCIATES, MAY 13, 2002.)

SCOMM

129:1

Subject: Web site posting of poll results and your Committee members.
Date: Mon, 18 Jun 2001 21:20:02 -0800
From: "Scott R. Heyworth" <heyworth@alaska.net>

Dear Joint Pipeline Committe Members:

I want you all to know that I posted the following on my website.....www.alaskagaspipeline.org recently.

I also, again, attached part of my Statewide Poll from late May just in case you missed it. I will be releasing the rest of my poll soon and I believe you and many Alaskans will also be interested in these other results.

My statewide poll asked over 40 questions. To date I have only released 14 responses.

My 2 polls and one other statewide done in February all clearly give the majority to the Valdez route.

Without question, Alaskans favor Valdez and do not back the Governor on any question posed to them. Alaskans have their minds made up already.

I encourage you all to fund a "Best Interest Finding" on the best gas pipeline route for Alaskans as we are the people you represent and not the Oil Companies.

Thank you,

Scott Heyworth.

The state legislative leadership announced the members of the Joint Committee on Natural Gas Pipelines on Sunday, June 10.

Appointees from the senate are: John Torgeson, R-Kasilof, Rick Halford, R-Chugiak, Pete Kelly, R-Fairbanks and Johnny Ellis, D-Anchorage. Appointees from the house are: Joe Green, R-Anchorage, Brian Porter, R-Anchorage, Scott Ogan, R-Palmer, and John Davies, D-Fairbanks.

The committee will hold hearings on natural gas development. The committee will represent the legislature and therefore the people of Alaska in dealing with the players such as the Canadians, Governor, Oil Companies, and U.S. Congress.

Our Gas, Our Future comments: All of these legislators represent Alaskans interests first. All of them are well aware of 3 state polls (see below for results) in the last 100 days which overwhelmingly and with out question show that Alaskans do not favor an Alaskan Highway route but actually heavily favor the LNG project to Valdez in every category of interest to Alaskans; Jobs, Revenues, Environment, Safety, and in-state Gas for all of Alaska, etc., etc., etc.

We continue to advocate for a "Best Interest Finding" by the legislature to determine which route actually brings the most benefit to Alaskans, as our state Constitution, Article 8, Section II clearly mandates. Our Gas, Our Future is of the belief they will do so in the best interest of our state.

This committee has the power to enact the funding and hire the independent analysis to represent Alaska's citizens in this arena. To simply take any findings by the Oil Industry as what is in the best interest of Alaska is totally inappropriate.

After all, it is Our Gas and Our Future!

Our Gas, Our Future

June 4, 2001

PRESS RELEASE

Alaskans clearly prefer a Valdez gas pipeline route to an Alaska Highway route

Our Gas, Our Future recently commissioned Ivan Moore Research to conduct a statewide registered voter survey looking deeper into the gas pipeline issue. The survey was conducted in May 2001 with a random sample of 385 Alaska super voters around the state.

Results again show an overwhelming preference for a Valdez Route over an Alaska Highway Route. The Northern Route barely registered.

On ten criteria of evaluation, respondents were asked to identify which of the three routes would be best, a Highway Route, a Valdez Route or a Northern Route. On all ten criteria, a Valdez Route was the public's unanimous selection.

In the Anchorage Daily News on June 1, 2001, Governor Tony Knowles rightly identifies "All Alaskans" as the owners of North Slope Natural Gas, but continues to ignore what Alaskans think. The gas pipeline route that Governor Knowles and the oil companies are proposing is <u>not</u> the gas pipeline route that Alaskans, the owners of the gas, think is best.

Are the Governor and the oil companies right to want to route a pipeline through Canada? Or are the people of Alaska right to want to keep it in Alaska?

Governor Knowles likes the Highway, but...

Alaskans seize Valdez!

PO Box 100531 Anchorage, AK 99510 ◆907 277-9981 ◆info@alaskagaspipeline.org www.alaskagaspipeline.org

➢ There have been several options suggested for the transportation of North Slope natural gas to market. I am going to read you three alternatives, and I'd like you to tell me whether you strongly favor, mildly favor, mildly oppose or strongly oppose each option. (RANDOMIZE ORDER OF OPTIONS)

- A Highway Route which goes south from the North Slope to Fairbanks, then east along the Alaska Highway, through Canada, connecting with existing gas pipelines near Calgary, Alberta, and down to the Lower 48.

	PIPELINE ROUTE ALONG ALASKA HIGHWAY - #1:		
	Count	%	
Strongly Favor	100	26.0%	Mean=2.334
Mildly Favor	124	32.3%	
Neutral	29	7.6%	
Mildly Oppose	67	17.5%	
Strongly Oppose	64	16.7%	

- A Valdez Route which goes south from the North Slope following the oil pipeline through Fairbanks and south to Valdez, where it is converted to Liquid Natural Gas and shipped out by tanker.

	PIPELINE ROUTE THROUGH FAIRBANKS AND VALDEZ - #2:		
	Count	%	
Strongly Favor	144	37.4%	Mean=2.766
Mildly Favor	129	33.6%	
Neutral	24	6.2%	
Mildly Oppose	52	13.6%	
Strongly Oppose	35	9.1%	

- A Northern Route which goes east along the North coast of Alaska, into Canada, then south down the McKenzie River delta, connecting with existing gas pipelines near Calgary, Alberta, and down to the Lower 48.

	PIPELINE ROUTE THROUGH MCKENZIE RIVER DELTA - #3:		
	Count	%	
Strongly Favor	9	2.3%	Mean=1.019
Mildly Favor	64	16.6%	
Neutral	31	8.2%	
Mildly Oppose	102	26.6%	
Strongly Oppose	179	46.4%	

➢ Which of these three options do you prefer most, the Highway route, the Valdez route or the Northern Route?

	MOST PREFERRED PIPELINE ROUTE:	
	Count	%
Alaska Highway Route	140	36.5%
Valdez Route	202	52.5%
Northern Route	15	3.9%
Don't know	28	7.2%

➢ Which of these pipeline options do you think…

- Would provide the most long-term jobs for Alaskans?

	WHICH PIPELINE PROVIDES THE MOST LONG-TERM JOBS FOR ALASKANS?	
	Count	%
Highway	81	21.1%
Valdez	217	56.4%
McKenzie	6	1.5%
Not sure	81	21.0%

- Would create the most revenues for the State of Alaska?

	WHICH PIPELINE CREATES THE MOST REVENUES FOR THE STATE OF ALASKA?	
	Count	%
Highway	71	18.4%
Valdez	193	50.2%
McKenzie	3	.8%
Not sure	117	30.5%

- Would have the least environmental impact?

	WHICH PIPELINE WOULD HAVE THE LEAST ENVIRONMENTAL IMPACT?	
	Count	%
Highway	102	26.4%
Valdez	169	44.0%
McKenzie	18	4.6%
Not sure	96	25.0%

- Could be completed most quickly?

	WHICH PIPELINE WOULD BE COMPLETED MOST QUICKLY?	
	Count	%
Highway	84	21.8%
Valdez	194	50.5%
McKenzie	5	1.2%
Not sure	102	26.5%

- Would provide for the safest transportation of gas?

	WHICH PIPELINE PROVIDES FOR THE SAFEST TRANSPORTATION OF GAS?	
	Count	%
Highway	114	29.5%
Valdez	150	38.8%
McKenzie	8	2.0%
Not sure	114	29.6%

- Would serve the most markets?

	WHICH PIPELINE WOULD SERVE THE MOST MARKETS?	
	Count	%
Highway	105	27.2%
Valdez	128	33.3%
McKenzie	12	3.2%
Not sure	140	36.3%

- Is in the best interests of Alaska?

	WHICH PIPELINE IS IN THE BEST INTERESTS OF ALASKANS?	
	Count	%
Highway	89	23.0%
Valdez	217	56.3%
McKenzie	6	1.4%
Not sure	74	19.2%

- Is in the best interests of the oil companies?

	WHICH PIPELINE IS IN THE BEST INTERESTS OF THE OIL COMPANIES?	
	Count	%
Highway	54	14.1%
Valdez	110	28.5%
McKenzie	25	6.6%
Not sure	196	50.8%

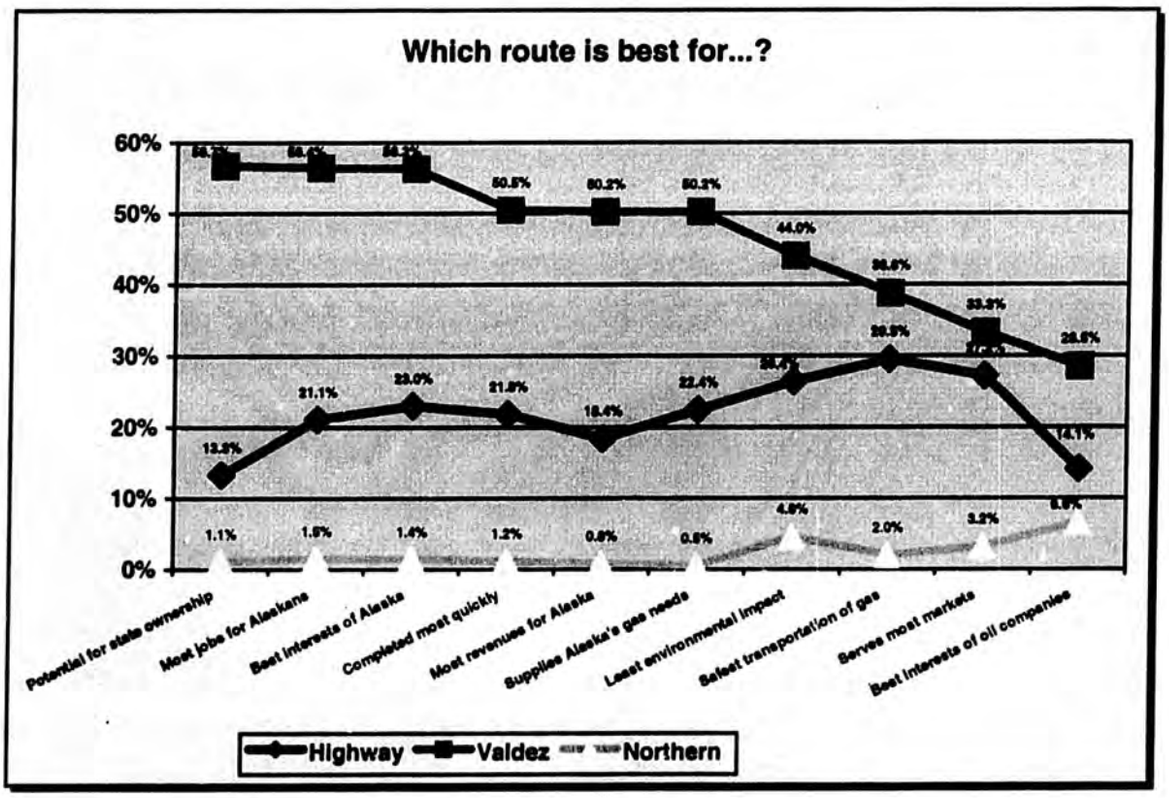
- Has the most potential for state ownership?

	WHICH PIPELINE HAS THE MOST POTENTIAL FOR STATE OWNERSHIP?	
	Count	%
Highway	51	13.3%
Valdez	218	56.7%
McKenzie	4	1.1%
Not sure	111	28.9%

PO Box 100531 Anchorage, AK 99510 ◆907 277-9981 ◆info@alaskagaspipeline.org www.alaskagaspipeline.org

- Provides the most opportunity for supplying Alaska's gas needs:

	WHICH PIPELINE PROVIDES THE MOST OPPORTUNITY FOR SUPPLYING ALASKA'S GAS NEEDS?	
	Count	%
Highway	86	22.4%
Valdez	193	50.2%
McKenzie	2	.5%
Not sure	103	26.8%



Percents do not add up to 100% - the balance in each case are "don't know" responses. In the case of Best interests of oil companies, "don't know" responses exceeded 50%.

The results are overwhelming. Selection of Valdez is unanimous in the ten cases, and in excess of 50% for six of the ten.

ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

Official Business

Senator John Torgerson, Chair
Senator Rick Halford
Senator Pete Kelly
Senator Johnny Ellis

Representative Joe Green, Vice-Chair
Representative Brian Porter
Representative Scott Ogan
Representative John Davies

AGENDA

Anchorage Legislative Information Office
Basement Conference Room

July 17 & 18, 2001

Tuesday, July 17

1. 9:00 a.m - Call to Order and Introductions

2. 9:05 - 10:00 a.m. - Federal Issues

   Staff, Congressional Delegation

   In May, President Bush issued his National Energy Policy. Senator Murkowski introduced legislation dealing with the President's policy. A competing energy bill was introduced by the Democratic members of the committee. Representatives from the Congressional Delegation will talk about President Bush's National Energy Policy, pending legislation concerning that policy, and other events happening in Washington D.C. relating to gas line developments.

Session: January – May
State Capitol, #427
Juneau, AK 99801
Phone: 907-465-2828
Fax: 907-465-4779

Interim: May – December
35477 Kenai Spur Hwy., Suite 101A
Soldotna, AK 99669
Phone: 907-260-3041
Fax: 907-260-3044

3. 10:00 – 11:30 a.m. - Pipeline Access Issues

   a) 10:00 – 10:30 a.m. - Carol E. Connors or designee, Deputy Director of Congressional, Intergovernmental and Public Affairs, Federal Energy Regulatory Commission
   b) 11:00 – 11:30 a.m. – Nan Thompson or designee, Commissioner and Chair, Regulatory Commission of Alaska

   The Federal Energy Regulatory Commission and the Regulatory Commission of Alaska will regulate an Alaska natural gas pipeline to the lower 48. These regulators will discuss issues important to Alaska oil and gas companies, other Alaska businesses, and Alaska citizens. They will talk about the relationship between the two commissions, how access to the pipeline by gas producers will be determined, how businesses and communities within Alaska will be able to take gas from the pipeline, and issues relating to the expansion of a pipeline. They will also give an overview of the timing and processing of an application.

4. 11:30 a.m. – 12:45 p.m. – Lunch Break

5. 12:45 – 1:45 p.m. – Report on Market Conditions

   Ed Small, Canadian Representative, Cambridge Energy Research Associates

   Cambridge Energy is a world renowned expert on oil and gas issues. They have been retained to advise the State of Alaska about gas market conditions. They will address the most current aspects of the gas market in the Lower 48 and Canada.

6. 1:45 – 2:45 p.m. – Update on SB 158 and Economic Models.

   a) Wilson Condon, Commissioner, Department of Revenue

   This year, the legislature passed SB 158 which required the Department of Revenue to hire an expert on financing and possibilities for state participation in the ownership of an Alaska natural gas pipeline. Commissioner Condon will give a report on the current status of the department's efforts in response to SB 158.

   b) Roger Marks, Economist, Department of Revenue

   The Department of Revenue, in conjunction with various companies and experts, developed an economic model for different pipeline alternatives. Mr. Marks will discuss the purposes of an economic model, how the gas model was created, and how it works.

7. 2:45 – 3:30 p.m. – Royalty In-Kind Issues and Pipeline Studies.

   Patrick Pourchot, Commissioner, Department of Natural Resources

   The people of the State of Alaska are particularly concerned about in-state usage of gas from Alaska's North Slope. Commissioner Pourchot will talk about how the state can support access to a gas pipeline by non-owner/producers, the state's right in general to take royalty in-kind gas both before and after construction of a pipeline, and how the state can support usage of gas by Alaskan businesses and communities. In addition, he will address the status of discussions with Netricity for the sale of royalty gas to generate electricity for

data centers that would service the demands of the Internet. The Commissioner will also report on Department of Natural Resources studies and other activities to advance an Alaska natural gas pipeline.

8. 3:30 – 4:30 p.m. – Right of Way Pipeline Applications

   a) 3:30 – 4:00 p.m. - John Goll, Alaska Regional Director, U.S. Mineral Management Service (MMS)
   b) 4:00 – 4:30 p.m. - William G. Britt Jr., State Pipeline Coordinator, Joint Pipeline Office

   Yukon Pacific has a conditional right of way for a LNG pipeline route from the North Slope to Valdez. Foothills has "renewed" its application for a gas pipeline from the North Slope to Lower 48. The Producers Pipeline Team is doing pre-application work on alternative routes for a gas pipeline. Mr. Goll and Mr. Britt will discuss the status of these applications and the work that is being done on them this summer.

9. 4:30 – 5:00 p.m. Discussion with Governor's Alaska Highway Natural Gas Policy Council

   Jim Sampson, Co-Chair Alaska Highway Natural Gas Policy Council, and
   Frank Brown, Co-Chair Alaska Highway Natural Gas Policy Council

Governor Knowles appointed a group of Alaska citizens to help him understand Alaska public policy issues relating to the construction of a natural gas pipeline. The policy council has formed various subcommittees to deal with issues regarding Alaska hire, royalty in-kind, pipeline ownership, federal and international relations, in-state access to gas, and environmental concerns. The council has met in several locations throughout the state. The Chairs of the council will brief the committee on their activities, and discuss ways in which this committee and the council may coordinate their activities.

10. 5:00 p.m. - Public Testimony on Agenda Items (limited to three minutes per speaker)

Wednesday, July 18

1. 9:00 a.m - Call to Order and Introductions

2. 9:05 – 12:00 noon - Presentations by Gas Line Groups

   a) 9:05 – 10:00 a.m. - Alaska Gas Producers Pipeline Team

   Joseph P. Marushack, Vice President, ANS Gas Commercialization, Phillips Alaska, and
   Ken Konrad, Sr. Vice President, Business Unit Leader Alaska Gas, BP Exploration

   The Alaska Gas Producers Pipeline Team is composed of BP Exploration, ExxonMobil and Phillips Alaska, three of the largest oil and gas producers in Alaska. The team is dedicated to commercializing ANS gas via an overland gas pipeline to the lower 48 and Canadian markets. The team is studying various alternative routes including a Beaufort Sea and an Alaska Highway route. The team's representatives will give the committee a brief overview of the team's work, progress to date, and future plans. Additionally, they will address what they believe to be key issues for the State of Alaska.

   b) 10:00 – 10:45 a.m. - Yukon Pacific Corporation

   Jeff Lowenfells, President and CEO

   Yukon Pacific (YPC) is a company devoted to an LNG project which delivers Alaska North Slope gas to Asian

and other markets. YPC possesses certain permits and rights-of-ways for this project. Mr. Lowenfells intends to update the committee on cost estimates for the project, including the construction of a spur line from Glenallen to Sutton. He will discuss the delivery of Alaska North Slope gas to U.S. markets via LNG. In addition, he will present information on Asian LNG markets.

c) 10:45 – 11:30 a.m. – Foothills Pipe Lines

John R. Ellwood, Vice President, Engineering and Operations

Foothills is a joint-venture company formed by TransCanada Pipelines Limited and Westcoast Energy, two of Canada's largest pipeline companies. Foothills was originally formed to build the Canadian portions of the Alaska Natural Gas Transmission System (ANGTS.) Today Foothills is the operator of the ANGTS project, which possesses certain permits and rights-of-way for a gas pipeline along the Alaska Highway through Alaska and Canada. Mr. Ellwood will update the Legislature on Foothills' recent activities in support of the ANGTS project, including discussions with the Alaska Gas Producers Pipeline Team, negotiations with "withdrawn partners," and the status of permits and rights-of-way.

d) 11:30 – 12:00 noon - LNG Sponsor Group

Steve Alleman, Commercial Manager, Alaska North Slope LNG Project

The LNG project is a group composed of Phillips Alaska, BP Exploration, Foothills Pipelines and Marubeni Corporation. Their goal is to develop an economic and commercially viable LNG project for North Slope gas. They have been studying two routes, one from the North Slope to Valdez and the other from the North Slope to Nikiski. Mr. Alleman will provide an update for the committee on their activities since their last presentation to the Legislature in March.

3. 12:00 noon – 1:15 p.m. – Lunch Break

4. 1:15 – 2:45 p.m. - Continuation of Presentations by Gas Line Groups

e) 1:15 – 1:45 p.m. - Alaska Port Authority

Dave Dengel, Interim Executive Director, Alaska Port Authority

The port authority was created under Alaska statutes allowing separate port authorities to be formed by municipal governments. Voters in the City of Valdez, Fairbanks North Star Borough and North Slope Borough approved its creation in October 1999. The purposes of the port authority include creating jobs, providing gas to Alaskan communities and helping stabilize the state economy by helping commercialize stranded North Slope gas. The port authority plans to use tax-exempt public debt financing for a portion of the project to lower costs and dramatically increase the economic viability of a large gas project, and maximize benefits to both Alaska and the

producer companies. Mr. Dengel will describe the port authority and its activities to the committee.

f) 1:45 – 2:15 p.m. - Kenai Peninsula Borough

Dale Bagley, Mayor

Officials from the Kenai Peninsula Borough will make a presentation to the committee regarding the benefits of a spur line to the Kenai Peninsula.

g) 2:15 – 2:45 p.m. – Williams Energy Services

Jeff Cook, Vice President External Affairs

Williams owns and operates a refinery in North Pole, Alaska. It markets its petroleum products throughout the State of Alaska. In addition, Williams is a major pipeline owner in the lower 48. Williams will be making a presentation on the possibilities of in-state processing of Alaska's North Slope gas.

5. 2:45 – 3:45 p.m. – Additional Testimony by Invitation of the Chair

6. 3:45 – 4:30 p.m. - Joint Natural Gas Pipeline Committee Meeting (Agenda to follow)

7. 4:30 p.m. - Public Testimony on Agenda Items (limited to three minutes per speaker)

ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

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Senator John Torgerson, Chair
Senator Rick Halford
Senator Pete Kelly
Senator Johnny Ellis

Representative Joe Green, Vice-Chair
Representative Brian Porter
Representative Scott Ogan
Representative John Davies

MEETING AGENDA

Wednesday July 18, 2001 3:45 – 4:30 p.m.

1) Future Meetings
   a) Fairbanks, August 14th – 15th, location to be announced
   b) Kenai, September, dates to be announced

2) Protocol for upcoming trips
   a)Whitehorse, Yukon
   b)Yellowknife, N.W.T.
   c)Victoria, B.C.
   d) Edmonton, Alberta

3) Contracting a firm to monitor activities in U.S. House and Senate

4) Legal Opinions Reports through Leg Council
   a) Fiscal Regimes
   b) Open season/Access
   c) Models on GTL, LNG, Alcan OTT, Pipeline Routes
   d) FERC issues/ RCA issues
   e) ANGTA vs. Natural Gas Act

Session: January – May
State Capitol, #427
Juneau, AK 99801
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Interim: May – December
35477 Kenai Spur Hwy., Suite 101A
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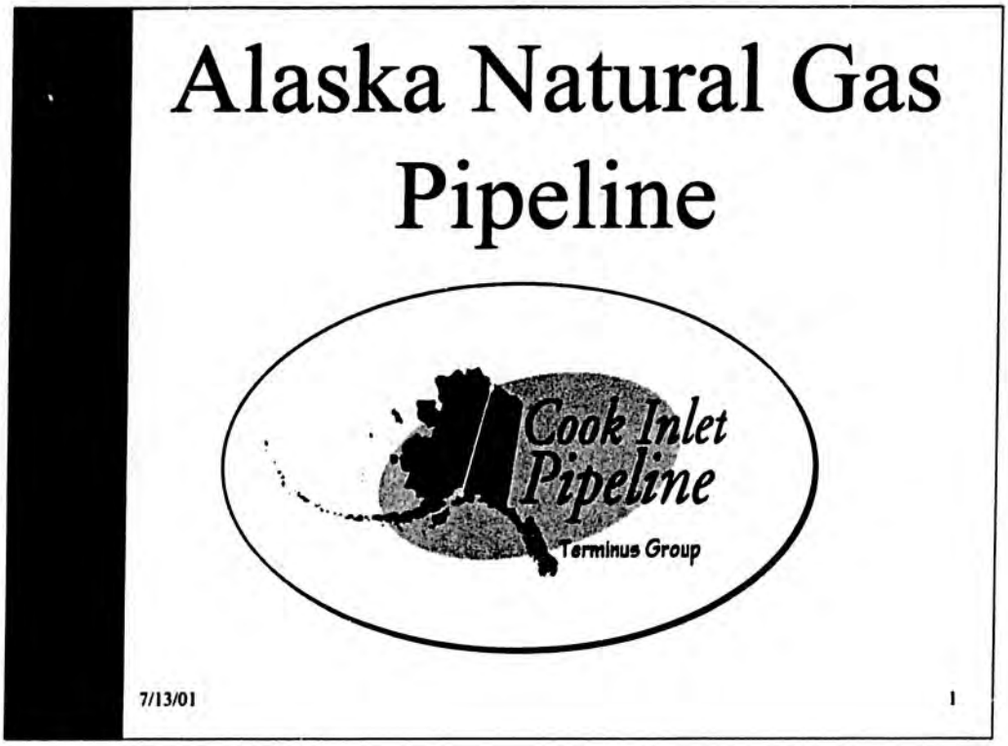
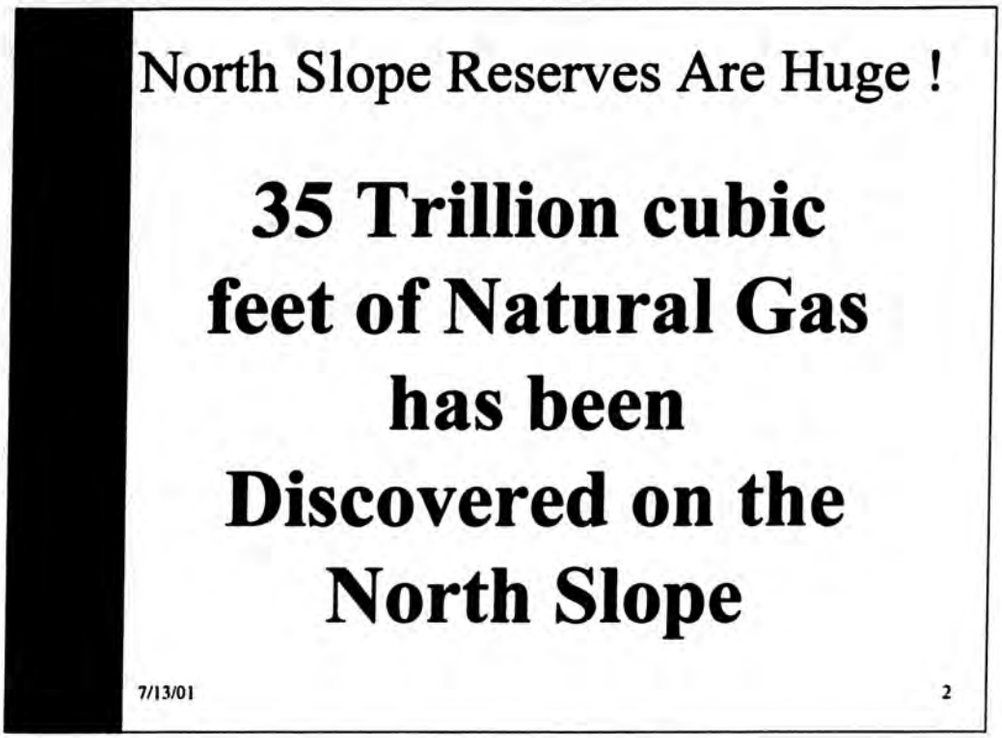


Borough Mayor Dale Bagley, chair

The Cook Inlet Pipeline Terminus Group has been meeting since the first week of January of 2000. Our group has representatives from the Kenai Peninsula and Mat-Su.

The Cook Inlet Pipeline Terminus Group's main goal goal is to promote a Cook Inlet route which provides the most benefit to Alaska.

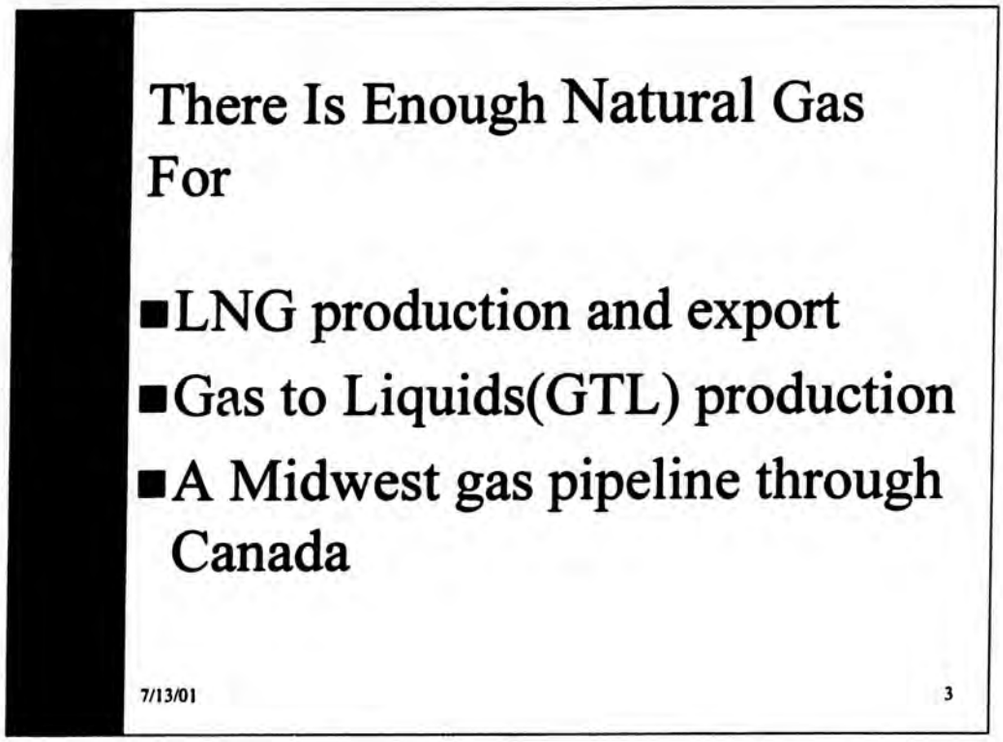
You have a brochure in front of you that has the main points of our presentation as well as our website address.



35 Trillion cubic feet of natural gas has been discovered on the North Slope, and no one has been looking. When a pipeline is built, the search for natural gas will really begin.

There are some predictions that 110 Trillion cubic feet will be discovered on the North Slope.

To put this into perspective, Enstar provides for the natural gas needs of 100,000 consumers in Mat-Su, Anchorage, and the Kenai Peninsula. They use approximately 50 Billion cubic feet of Natural Gas per year. 35 Trillion cubic feet is enough natural gas to last current Enstar consumers for 700 years. Actual reserves could easily last consumers for over 2,000 years. The bottom line, is that there is plenty of natural gas for "in state" use as well as export use.



There is enough natural gas on the slope for a LNG export pipeline, Gas to Liquids production, and a gas line to the Midwest.

BP is currently constructing an $86 Million Dollar Gas To Liquids Pilot Plant in Nikiski. Actual plant construction will began in a couple weeks.

The Midwest/Canadian gas pipeline is becoming more likely everyday.

If the instate LNG pipeline is built along with the Midwest pipeline, both projects can share costs from the North Slope to Fairbanks, making both projects more economically feasible. Both groups that are proposing an LNG line are looking to cost share with the Midwest line to Fairbanks.

The important point is; these projects are not in competition with each other. There is enough gas for one LNG export pipeline, Gas To Liquids production and, a Midwest pipeline.

The Sponsor Group

- Phillips Alaska Inc.
- Foothills Pipe Lines, Ltd.
- Marubeni Corporation
- BP Exploration Inc.

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Phillips has been safely producing, shipping and marketing LNG from Nikiski for 32 years. Since acquiring ARCO, Phillips now has a 44% ownership in the Sponsor Group.

Foothills Pipeline a Canadian firm has arctic natural gas pipeline construction, expertise and experience. Foothills is also looking at the Midwest pipeline. (25%)

Marubeni Corporation, a Japanese company with Asian market experience has opened a Sponsor Group Office in Japan. (19%)

BP is a recent addition to the Sponsor Group. BP would like to see natural gas for their Gas To Liquid pilot plant in Nikiski. They are also looking at the Midwest pipeline. (12%)

These are the right players. They have natural gas reserves, they have the expertise & experience that comes from decades of producing natural gas. They have world wide natural gas marketing experience. They have successfully permitted and built projects throughout the world.

The Sponsor Group has completed Phase I of their Feasibility Study

- Looking at a Cook Inlet terminal

Or

- Anderson Bay near Valdez



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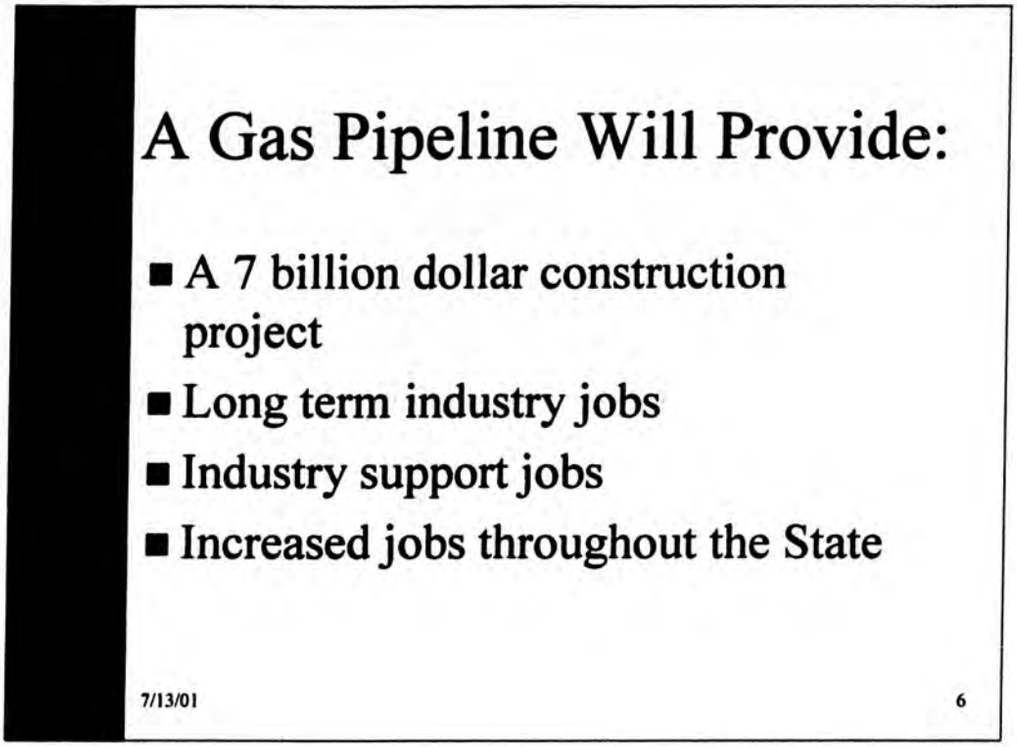
The Sponsor group has finished Phase 1 of their feasibility study. They spent $20 Million dollars in the first phase and are now in Phase 2.

During the 1st phase, they considered routes all across Alaska. They narrowed their choice to a Cook Inlet route and a Valdez route. Soon they will make a decision between the two routes.

On the map and you will see that the proposed Cook Inlet pipeline will follow the Oil Pipeline from the North Slope to Fairbanks. From Fairbanks the proposed pipeline will branch off to Cook Inlet.

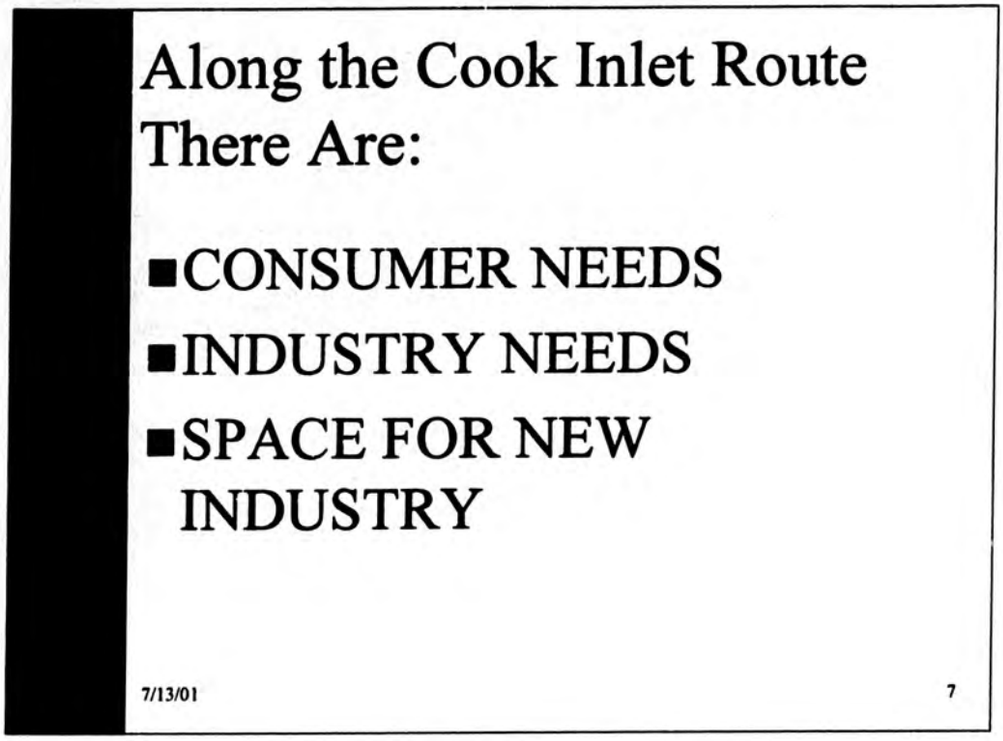
The Port Authority group is proposing a line just to Valdez with consumers in the South Central area paying for a residential line from Glenallen to South Central.

And if the over-the-top route happens it may be awhile before a stand-alone LNG North Slope to tidewater pipeline will be economically feasible.



The Cook Inlet LNG line will be a $7 Billion dollar construction project. In addition to the pipeline, there will be a conditioning plant on the North Slope, and a $ 1 Billion dollar LNG Plant.

There will be jobs during the engineering phase and during pipeline construction. There will be permanent jobs along the pipeline route, and at the LNG plant located at the pipeline terminus. There will be jobs from support industries that will develop throughout the state. These will be quality jobs that will boost growth in Alaska and will create many more jobs through out our economy.

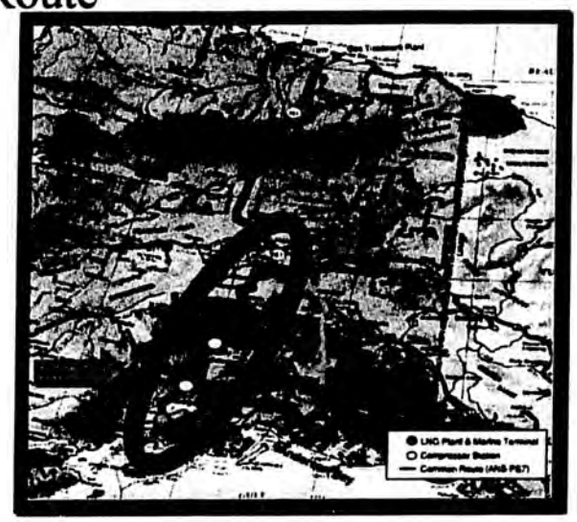


Read

These are the three main reasons for a Cook Inlet LNG line.

Consumer Needs

70% Of Alaskans Live Along the Cook Inlet Route



7/13/01

8

Consumer Needs

The Gas reserves in the Cook Inlet area are declining and are not estimated to last longer than 20 – 30 years.

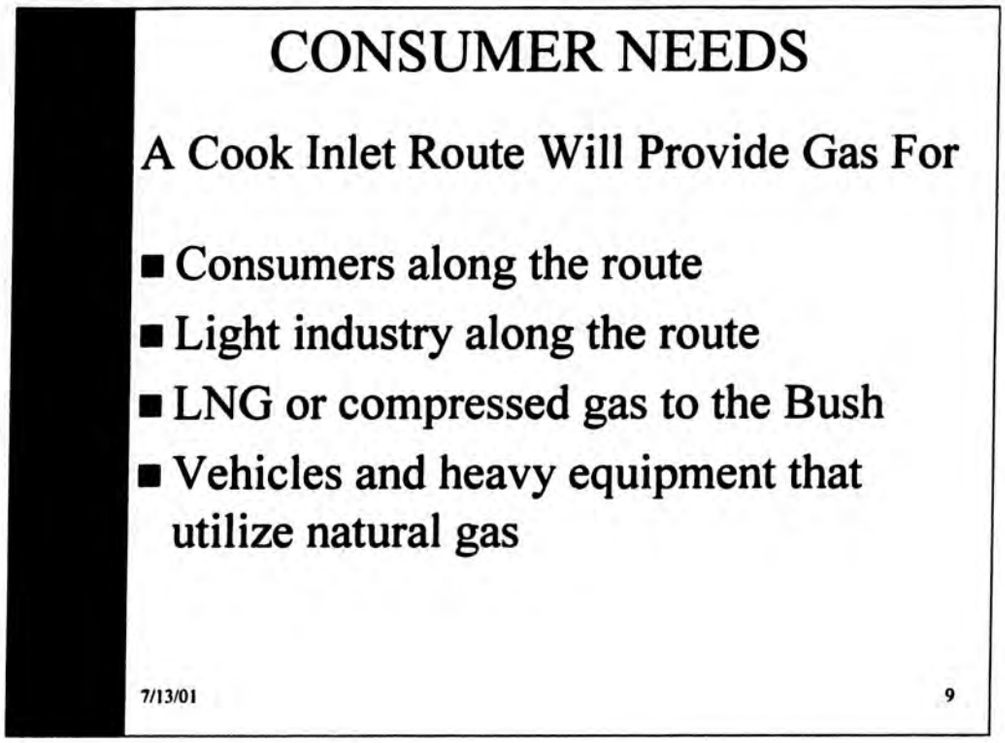
Locating the terminus on Cook Inlet is the only option that serves the majority of Alaskan consumers.

70% of all Alaskans live along the route or in the Cook Inlet area.

There are consumers along the route including Nenana, Healy, Denali, Talkeetna.

Anchorage has many residential and business consumers.

Mat-Su is the fastest growing area in Alaska. This growth needs natural gas. The Port MacKenzie project could use this gas to expand their industrial area near the port.



Natural Gas can be used to make electricity, adhesives, fertilizer, fuel cells and things we haven't even thought of yet.

Nenana could use barges to ship compressed gas or LNG to villages in the bush.

Fleet vehicles could switch over to natural gas.

This pipeline should benefit the majority of Alaskans.

INDUSTRY NEEDS



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Industry Needs

Agrium

Phillips LNG plant

Tesoro

BP's Gas to Liquids Plant

APC Pipeyard

Room to grow

INDUSTRY NEEDS

AGRIUM



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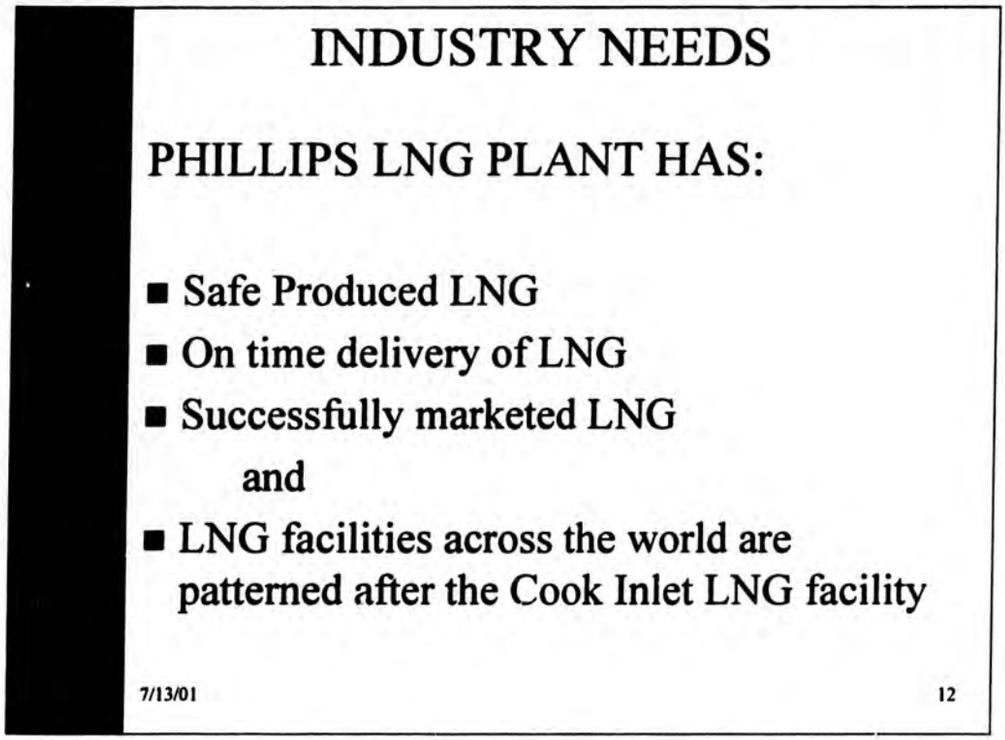
Industry Needs

Agrium is the biggest taxpayer on the Kenai Peninsula.

Agrium is also the largest employer on the Kenai Peninsula with a $30 Million dollar annual payroll.

Agrium, who is the largest fertilizer producer in the world, recently bought this fertilizer plant. They have plans to expand this facility and need plenty of gas.

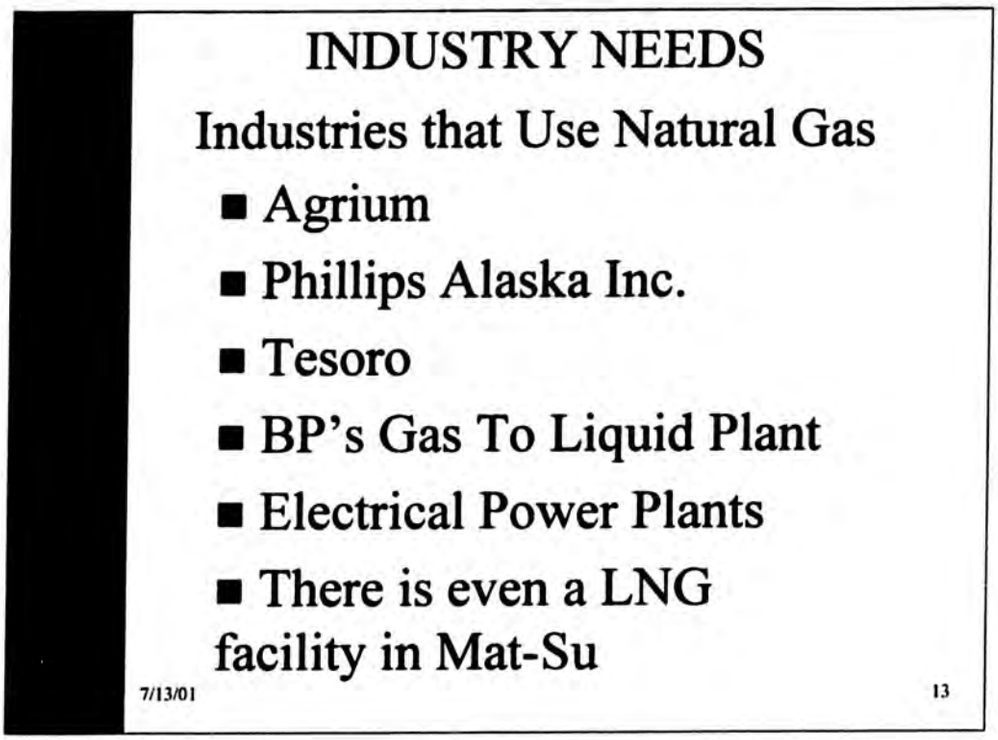
A Cook Inlet LNG pipeline protects existing industry jobs and provides new jobs.



Phillips Alaska has been producing LNG for 31 years.

LNG tankers come into Cook Inlet every 10 days.

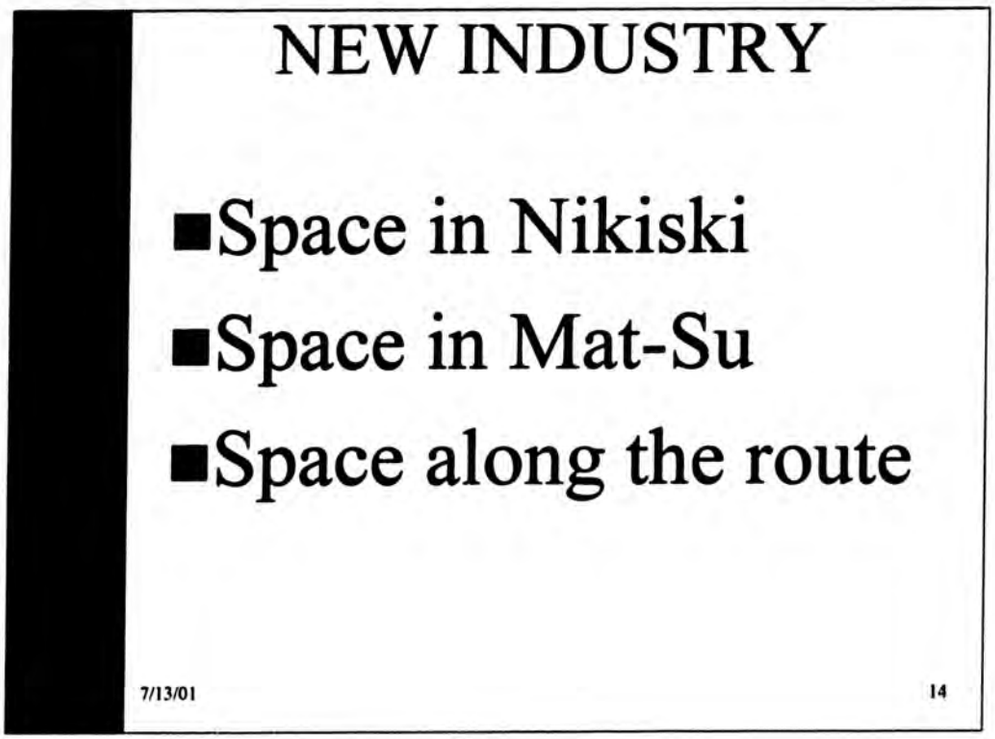
The Phillips Alaska LNG plant on Cook Inlet is known across the world as the premier LNG facility. It was the world's largest, and now serves as a prototype for new facilities.



South Central Alaska has thousands of residents who work for natural gas dependant industries.

As South Centrals consumer needs continue to grow there will be less natural gas available for industry use.

We need the Alaska natural gas pipeline to protect these and other jobs.

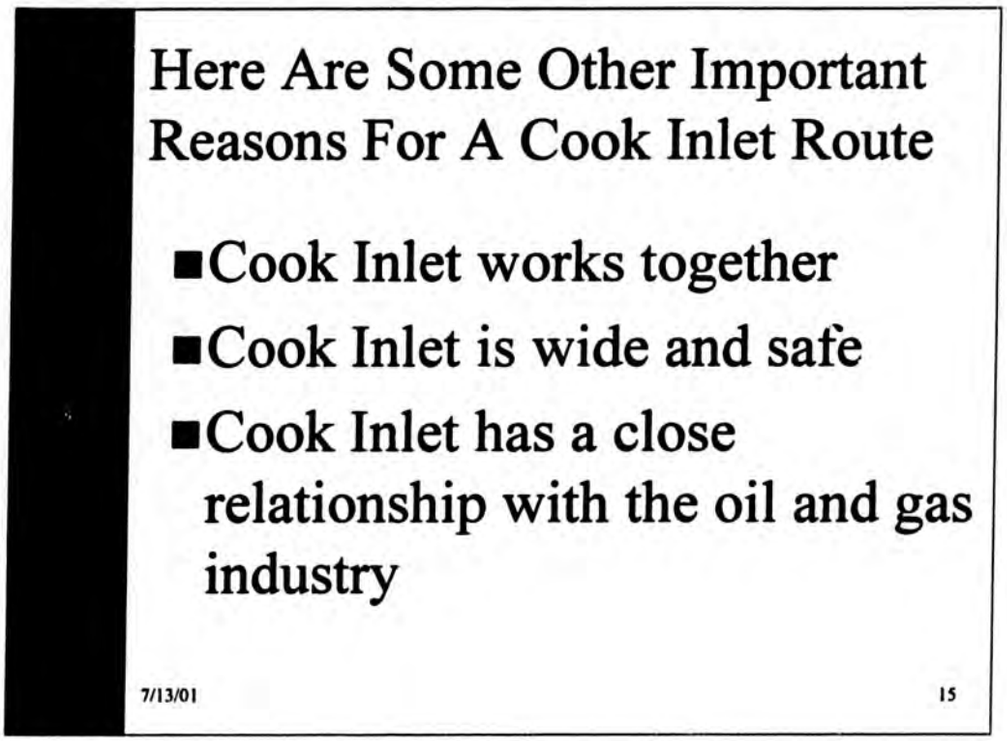


Space for new industry

The Cook Inlet route has space for the large LNG facility as well as space for new industry.

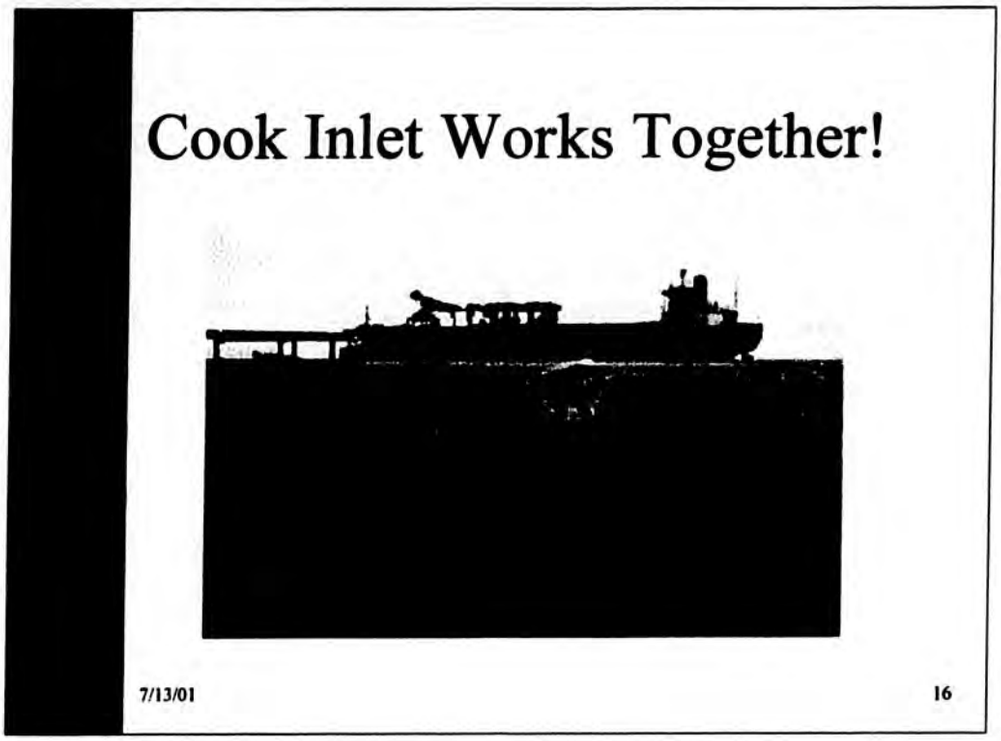
We have had new industry look a Cook Inlet, but there wasn't a guaranteed supply of natural gas for them.

Having that guaranteed supply of natural gas opens up all sorts of possibilities for communities along the Cook Inlet route.



Again, The three main reason for the LNG gas pipeline to end at Cook Inlet is to provide for instate consumers, provide for industry, and because the Cook Inlet route has the space for the LNG Plant & for new industry.

But there are some other reasons as well.



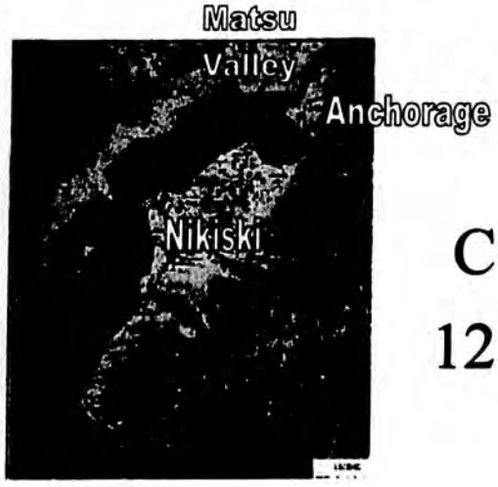
Cook Inlet's oil and gas industry has always worked together with the commercial fishing industry and tourism industries.

Here you have a picture of fishermen tending the nets on Cook Inlet. The ship in the background is loading at the Agrium dock.

Cook Inlet works together. Every August we have an industry appreciation day to thank the oil and gas industry as well as the commercial fishing and tourism industries.

You are all invited to join us this year on Saturday August 25, at the Kenai Green Strip for the Industry Appreciation Day Celebration. The music is great, the food is great and you will be enjoying the afternoon with 5000 of the nicest people you could hope to meet.

Cook Inlet Is Wide & Safe



Cook Inlet is 12 to 14 Miles Wide

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Cook Inlet is wide and safe. The narrowest part is 12 miles wide.

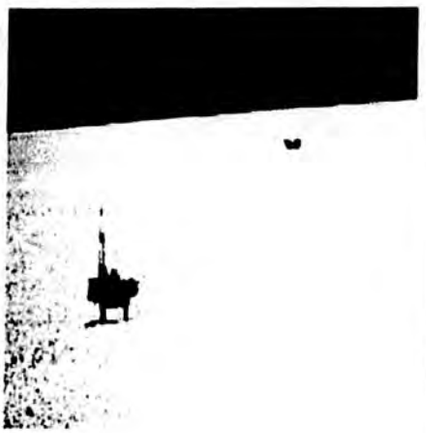
The natural geology of Upper Cook Inlet protects from tsunami damage.

Last year the 1000th ship load of natural gas was safely shipped through Cook Inlet.

And best of all we don't have icebergs or reefs in Cook Inlet.

Cook Inlet Enjoys

A close relationship with the Natural Gas Industry



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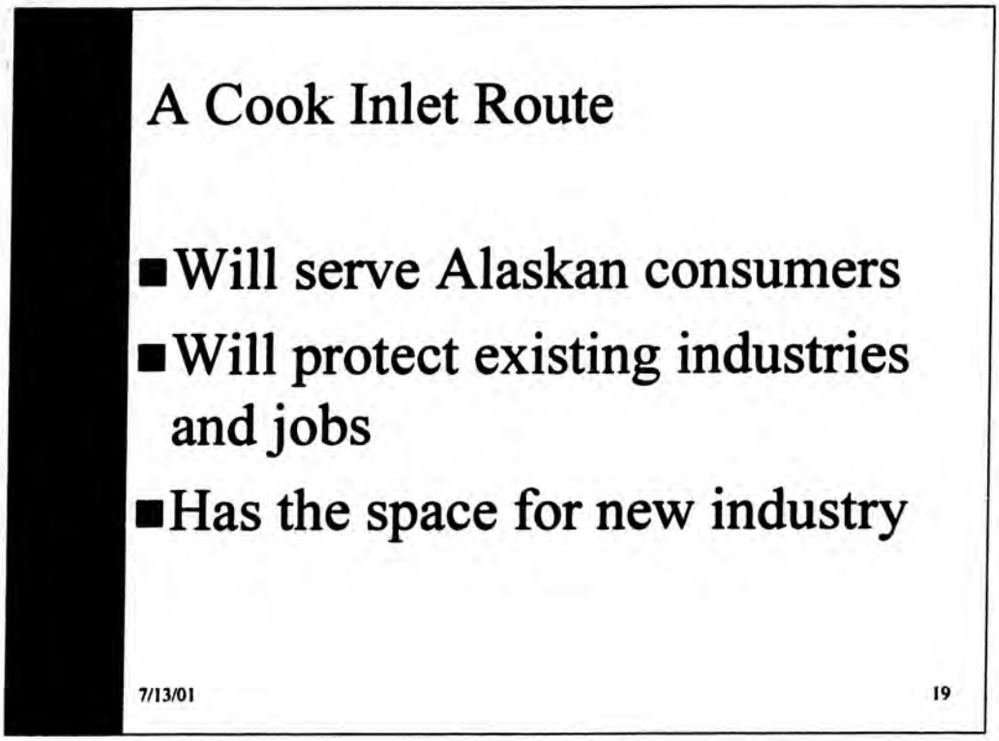
Cook Inlet has a close relationship with the natural gas industry.

The regulatory agencies are in place and familiar with Cook Inlet natural gas production and transport.

Cook Inlet has the trained work force and the infrastructure to support expanding the natural gas industry.



One again the 3 main reasons for a Cook Inlet route are

70% of Alaskan consumers live on the route to Cook Inlet. A Cook Inlet route will let them use natural gas for the first time or will insure that they don't run out of affordable natural gas.

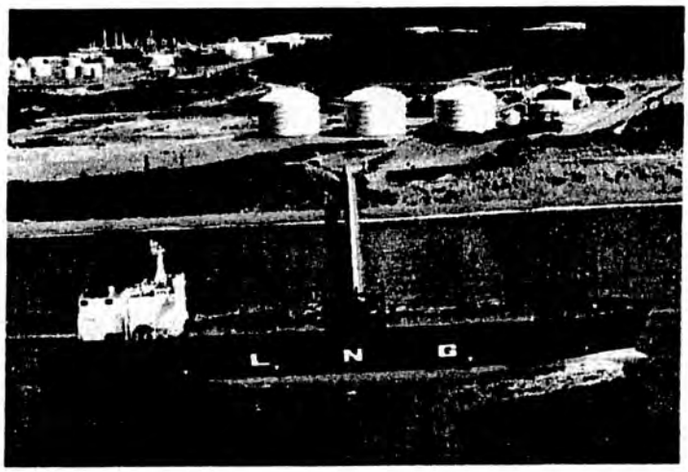
A Cook Inlet route will protect existing industries, and

There is space to build the LNG plant and develop new industry along the Cook Inlet route.

The sheer volume of natural gas will mean that most of the gas will be exported, but "in state" gas needs should not be ignored.

Alaska natural gas should warm Alaskan homes and fuel Alaska businesses and industry.

Cook Inlet Works For Alaska!



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This last slide shows a tanker in Cook Inlet loading LNG at the Phillips plant.

This concludes my presentation and I would be happy to answer questions.

Alaska North Slope LNG Project

TESTIMONY

to

Joint Committee on Natural Gas Pipelines

July 18, 2001

Mr. Chairman, for the record, my name is Steve Alleman. I reside in Anchorage and I am an employee of Phillips Petroleum Company. I am speaking to you today within the capacity of my current assignment as Commercial Manager for the Alaska North Slope LNG Project. Thank you for this opportunity to testify.

In presentations to the House Oil and Gas Committee this last February 27th and then to the Senate Resource Committee on April 7th, the Alaska North Slope LNG Sponsor Group indicated that it is in the midst of its Stage 2 activities that are scheduled for completion by the end of this year. Though most of those activities are still works in progress, I would like to briefly overview the ongoing LNG effort to this new committee.

The Sponsor Group began working in October of 1998 to try to make an Alaskan LNG project economically viable and cost competitive in the market. Phillips Petroleum Company, BP Exploration Alaska, Inc., Foothills Pipe Lines, Ltd. and Marubeni Corporation are the current and ongoing sponsors in this LNG effort.

From the very beginning, we have maintained a strong market focus. Most of our sponsors have personnel living and working in East Asia. We have longstanding LNG market relationships that allow us insight into what the marketplace is saying.

For example, early in Stage 1, we challenged the conventional wisdom that an Alaskan LNG project has to be sized at 14 or more million tons per year. Our market evaluation indicated that we needed a smaller project to give us the best chance of getting a toehold in this fiercely competitive LNG market place.

So the focus of the Stage 1 technical work was to innovatively redesign a smaller, market entry project where costs could be deferred and overall risks reduced and yet still be expandable later as demand grows. The result was a

7-8 million tons per year design, which we currently estimate would cost about $5 billion without ships. This market entry project is the basis for our point forward work.

Returning to the market, through our personnel in East Asia, we are quite aware that the East Asian market is very interested in Alaska LNG. There is no myth or mystery about the positives that the market sees in LNG from Alaska. But we are also very aware that this is only part of the story. The more crucial question is: Under what conditions would the market move from *interest* in Alaska LNG to *commitment* to purchase?

There is significant East Asian LNG competition in the form of potential and in-progress, large expansions and new grass roots LNG plants. As we detailed in presentations during the session, there are 60-80 million tons per year of potential LNG projects fiercely competing for 20-40 million tons of East Asian LNG demand that is projected to be needed by the end of the decade.

Unfortunately, Alaska is not yet cost competitive with the majority of those other LNG projects on a unit cost basis. Further, we cannot yet demonstrate an economically attractive capital pay back project with assumptions that are reasonably salable to the market or to investors. This all comes back to Alaska's unique competitive disadvantage: an 800-mile, gas pipeline to tidewater.

As to where we are today, the LNG Sponsor Group is in the last half of its Stage 2, work program. In Stage 2, we are using the Stage 1 market entry project design and working on primarily commercial, but also technical ways to reduce costs and risks. We expect to complete these deliverables on schedule, by the end of this year, and within our three million-dollar budget.

These efforts include continued engineering design and cost optimizations that have already identified over $400 million of additional capital cost reductions in this Stage.

The LNG Sponsor Group is currently evaluating synergy around sharing facilities with a southern route, lower 48 pipeline. There are cost saving opportunities in the gas treating plant and in the pipeline transportation and compression from Prudhoe to the takeoff point.

We should always keep in mind that while sharing infrastructure will reduce costs, it will not eliminate them. Costs for treating and transporting would be realized as either capital or as fees. We are in the middle of that evaluation, but intuitively, we don't expect sharing alone to eliminate the competitive disadvantage of the pipeline.

We mentioned during session that we have already looked into the potential value of a joint public/private entity in Stage 2 and have found no compelling advantage to such a joint project at this time. We have communicated this as part of ongoing discussions with the Gasline Port Authority, expressing to them in part, that any benefits passed to private enterprise will be taxable.

Further, public borrowing rates are unlikely to offset a private entity's potential tax deduction of interest and depreciation. We hasten to point out that this does not preclude a public entity from developing a competitive project on its own.

Also ongoing is an evaluation of key risks and mitigation strategies for this project. While this work is not finished, there have been no big surprises to date. Risk items such as price, price and cost escalation, cost overruns and other expected risk factors that are typical for any project of this magnitude, are also very much a part of this LNG project.

While much of our Stage 1 focus was on East Asian markets, we are currently exploring the potential for alternate markets in the lower 48 and Mexico. That effort is also in mid-cycle review and is on schedule for timely completion. We expect to find that the California/Mexico market is subject to the same market forces and that all other gas sources, including LNG import projects, will do their part to make this market fiercely competitive.

With this California/Mexico market focus, we have not forgotten about the East Asian marketplace in our Stage 2 efforts. Marubeni continues to staff our Market Liaison Office out of Tokyo to gather feedback and to respond to market questions. We are also in the process of analyzing other competing LNG projects into East Asia and how those projects are estimated to compare to our efforts on a cost of service basis. That evaluation is on schedule for completion by the end of the year.

However, as we presented during session, Alaskan LNG has a long way to go to be cost competitive on a unit cost basis into E. Asia, primarily because of the 400 to 800-mile, buried arctic pipeline. The industry benchmark for capital cost per million tons per year - or annum (MTPA), excluding ships, is reportedly around $250 million per MTPA. Because of the pipeline, unit costs for our Alaska LNG stand-alone project are above $600 million per MTPA.

Finally, an externally generated environmental assessment for permitting the Nikiski route is nearing completion. Once that work is done, we will develop an overall permitting strategy for expeditiously moving forward with either the Nikiski or Anderson Bay route and site, if market conditions and cost competitiveness improve to the point of initiating a project. While that external work has slipped about a month behind our original estimated schedule, it is still expected to be complete prior to the end of Stage 2

Hopefully this overview has given you a flavor for our past and ongoing efforts within the LNG Sponsor Group. As stated, we fully expect to complete our Stage 2 work on time and within budget before the end of this year. Once we have all of our results, we will then be in a much better position to determine what, of any, next steps make the most sense for LNG.

Thank you, Mr. Chairman and members of the Committee, for the opportunity to provide this overview of our ongoing work.

(1)

State of Alaska Department of Revenue

North Slope Gas Economic Model

Presentation to Alaska State Legislature
Joint Committee on Natural Gas Pipelines

July 17, 2001

(3)

Outputs

Financial feasibility (rate of return)

Tariffs / Wellhead values

State revenues

5

Example
Less Favorable Scenario

" bare bones - barely economic

ALCAN route to Alberta

$3 gas price in Chicago

$1.00 charge from Alberta to Chicago

4.0 billion cubic feet per day

$14 billion capital cost (highest, given range)
- $2.0 billion conditioning - (plant)
- $12.0 billion pipeline

No oil losses

No liquids

BASE

7

		STATE REVENUE - LESS FAVORABLE SCENARIO					
					State	Addit	
					Corp Inc	Sev Tax	
				State	Tax	from	
	Property		Severance	Corp Inc	from pipeline	ELF	
	Tax	Royalties	Tax	Tax	tariffs	Incr	Total
Year	($mm)	($mm)	($mm)	($mm)	($mm)	($mm)	($mm)
2002	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0
2004	4	0	0	0	0	0	3
2005	22	0	0	-2	-2	0	18
2006	136	0	0	-26	-9	0	100
2007	132	0	33	-11	-10	13	157
2008	127	0	71	50	11	21	281
2009	123	0	71	71	21	23	309
2010	118	0	71	90	29	24	332
2011	114	0	71	106	36	25	352
2012	110	0	71	119	42	28	369
2013	105	0	71	132	47	29	384
2014	101	0	72	140	49	30	391
2015	97	0	72	148	51	31	398
2016	92	0	72	155	53	31	403
2017	88	0	73	155	53	31	400
2018	83	0	73	162	59	31	409
2019	79	0	73	169	65	31	417
2020	75	0	74	169	66	30	414
2021	70	0	75	170	66	30	411
2022	66	0	75	171	66	29	407
2023	61	0	76	172	66	28	403
2024	57	0	76	196	73	27	428
2025	53	0	77	220	79	26	453
2026	48	0	77	221	79	24	449
2027	44	0	77	222	79	23	445
2028	39	0	78	223	79	21	441
2029	35	0	78	224	80	20	436
2030	31	0	79	224	80	18	432
2031	26	0	79	225	80	16	428
2032	22	0	80	226	81	15	423
2033	18	0	80	227	81	13	419
2034	13	0	80	228	81	11	414
2035	9	0	81	229	82	9	410
2036	4	0	81	230	82	7	405
	2202	0	2214	5035	1794	695	11940

assumes no price effect, keep everything constant

(9)

Volume sensitivity

4.0 billion cubic feet per day (bcf/d) with $3 gas price in Chicago with $14 billion capital cost:

Rate of return:	10.0%
Wellhead value:	4 cents
Total State revenue in 2015	$398 million

5.0 bcf/d:

Rate of return:	12.3%
Wellhead value:	40 cents
Total State revenue in 2015	$532 million

6.0 bcf/d:

costs go up when you change values

Rate of return:	14.5%
Wellhead value:	$0.64
Total State revenue in 2015	$695 million

max cap costs for 10% - $1 = 7 billion

BASE

(11)

STATE REVENUE - MORE FAVORABLE SCENARIO							
Year	Property Tax ($mm)	Royalties ($mm)	Severance Tax ($mm)	State Corp Inc Tax ($mm)	State Corp Inc Tax from pipeline tariffs (fees) ($mm)	Addit Sev Tax from ELF Incr ($mm)	Total ($mm)
2002	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0
2004	6	0	0	-1	-1	0	5
2005	33	0	0	-3	-3	0	27
2006	156	0	0	-28	-11	0	117
2007	151	102	54	65	-15	15	372
2008	146	204	118	210	10	24	711
2009	141	204	118	234	22	26	744
2010	136	204	118	255	33	26	771
2011	131	204	118	272	42	28	795
2012	126	204	118	288	49	30	815
2013	121	204	119	301	55	31	831
2014	116	204	119	310	58	32	839
2015	111	204	120	318	60	33	845
2016	106	204	120	325	62	33	850
2017	101	204	121	325	62	34	847
2018	96	204	121	335	71	33	860
2019	91	204	122	344	80	33	874
2020	86	204	123	345	80	33	871
2021	81	204	124	346	81	32	867
2022	75	204	125	347	81	31	863
2023	70	204	125	348	81	30	859
2024	65	204	126	372	88	29	883
2025	60	204	127	396	94	27	908
2026	55	204	127	397	94	26	903
2027	50	204	128	398	94	24	899
2028	45	204	129	399	95	23	894
2029	40	204	129	400	95	21	889
2030	35	204	130	401	95	19	884
2031	30	204	130	402	96	17	879
2032	25	204	131	403	96	15	875
2033	20	204	131	404	97	14	870
2034	15	204	132	405	97	12	865
2035	10	204	132	406	97	10	860
2036	5	204	133	407	98	8	854
	2535	6018	3668	10123	2132	747	25223

RCA Policy Goals

For gas pipelines within its jurisdiction, the RCA's policy goal is to ensure:

- Non-Discriminatory Access
- Just and Reasonable Rates

RCA Jurisdiction

- Our jurisdiction over intrastate movements within an interstate pipeline appears limited
  - Commingling doctrine generally makes intrastate gas "interstate" in nature
  - Opinion of State AG in 1977
  - Alaska Natural Gas Transportation Act, Sec. 13(b)

RCA Jurisdiction (cont.)

- Preemption issues aside, the RCA has no authority over an interstate pipeline unless the line starts off with an intrastate certificate.
  - Federal Case Law
  - State Pipeline Act

RCA Jurisdiction (cont.)

- RCA generally has jurisdiction over lateral lines.
- We are looking into these issues further. It appears though that if the State wants RCA to regulate intrastate transport, then:
  - Litigation or Federal legislation may be needed
  - RCA's authority would be greater if instate volumes were nominated at the beginning.

RCA Jurisdictional Pipelines

- For gas pipelines under its jurisdiction, the RCA can regulate a pipeline either as:
  - Pipeline Carriers (42.06)
  - Public Utilities (42.05)
- The Commission's powers to ensure shippers access tend to be greater for Pipeline Carriers than for Public Utilities.

Access

The RCA can:

- Allocate capacity if nominations exceed space (*Pipeline Carriers*);
- Order facilities expansion (*Pipeline Carriers* and *Public Utilities*);
- Order facilities interconnection (*Pipeline Carriers* and *Public Utilities*);

Access (cont.)

- Order installation of off-take facilities during construction (*Pipeline Carriers*).

Tariffs

- The RCA is charged with ensuring that tariffs under its jurisdiction are just and reasonable. This usually means that rates reflect the costs of providing service, including a reasonable return on capital.

Who pays for capacity additions?

- No clear rulemaking, nor much precedent for gas pipelines.
- The RCA would generally look at allocation of benefits arising from facilities expansion.
  - Connection costs generally paid by interconnecting entity
  - Costs of expansions conferring wider benefits would be paid for those who might benefit.

Who pays for capacity additions (cont.)?

- Capacity expansion costs for pipelines certificated under the Pipeline Act are more likely to be paid for by all users, since common carrier status means that all users may eventually benefit.

PRIMARY OBJECTIVES

- **INCOME TO STATE AND MUNICIPAL TREASURIES**
- **BENEFIT PEOPLE OF ALASKA**
- **BENEFIT ALASKA BUSINESSES and BUSINESSES OPERATING IN ALASKA**

PRIMARY OBJECTIVE: INCOME TO STATE AND MUNICIPAL TREASURIES

- Get North Slope gas to market
- Maximize royalty and tax value for each MCF of gas sold
  - Maximize selling price
  - Minimize pipeline tariff
  - Minimize field costs and conditioning costs
- Maximize quantity of gas sold without unduly compromising ultimate oil production
  - Minimize oil revenue losses incident to producing Prudhoe Bay gas
  - Sell gas not only from Prudhoe Bay and Point Thomson fields, but also gas from fields recently discovered and yet to be discovered (e.g. Foothills, NPRA)
- Maximize bids from leasing acreage underlain by gas
- Increase sources of property taxes (e.g. new pipeline(s) and facilities)

PRIMARY OBJECTIVE: BENEFIT PEOPLE OF ALASKA

- Increase income to state general and permanent funds and municipal treasuries
- Provide in-state jobs
- Increase in-state spending
- Supply natural gas to Alaska communities, where economic
- Minimize environmental impact of fuel usage and pipeline construction and operation
- Enhance and diversify business climate

PRIMARY OBJECTIVE: BENEFIT ALASKA BUSINESSES and BUSINESSES OPERATING IN ALASKA

- Make gas and gas liquids available for existing and new commercial, industrial, and power generation ventures, where reasonable
- Access to pipeline
  - Reasonable pipeline tariffs
  - In-state delivery locations
  - Right-size pipeline and any expansions
  - Prorate capacity when nominations exceed capacity
  - Nominations required a reasonable period in advance of shipping gas
  - No gaming of nominations
- Access to production and conditioning facilities
  - Reasonable facility charges
  - Allocate capacity, where insufficient

TOOLS TO ACCOMPLISH PRIMARY OBJECTIVES

- Federal
  - ANGTA Alaska Natural Gas Transportation Act
  - NGA Natural Gas Act
  - FERC Federal Energy Regulatory Commission
  - Right-of-Way Leasing for Federal Lands
  - New or Revised Federal Statutes
- State
  - RCA Regulatory Commission of Alaska
  - AOGCC Alaska Oil & Gas Conservation Commission
  - DNR Department of Natural Resources
    - Right-of-Way Leasing for State Lands
    - Plans of Development and Operations
    - Switching Between Taking Royalty In-Value and In-Kind
    - Royalty-in-Kind Sales and Options
  - State Ownership of Pipeline or Interest in Pipeline
  - Port Authority Financing
  - Alaska Stranded Gas Development Act
  - Statute Prohibiting Grant of Right-of-Way Easement for Beaufort Sea Route
  - Studies
  - New or Revised State Statutes

ROYALTY-IN-KIND

NETRICITY 8,500-119,000 mcf/d

- Interested in option on State's royalty gas to fuel electrical generation for internet data centers
- Netricity's offer of $0.36/mcf for gas sold on North Slope was calculated as follows:

Chicago market price	$ 4.50
Transmission Cost	$ 2.50
Net North Slope Price	$ 2.00
Discounted from midpoint in life of pipeline sales @ 10% per year	**$ 0.36**

- Value to State would be further reduced by:

PBU field costs, currently	-$ 0.21
Oil losses incident to gas sales	-$ 0 - $ 0.25
Net to State	**-$ 0.10 to $ 0.15**

- Advantages
  - In-state construction and operation jobs and spending
  - Increases North Slope property taxes
  - Possibly gas sales prior to completion of pipeline

ROYALTY-IN-KIND

NETRICITY: Current Status of Discusssions for RIK Option or Sale

- Discussion with Mike Caskey of Netricity July 6
- Meeting with Jim Dodson of Netricity July 19
- Awaiting results of gas valuation and in-state demand studies due in November
- Netricity is engaged in discussions with BP and Phillips for the purchase of their gas

continued . . . .

NETRICITY, continued

- **Based on currently available information, market value of gas is subject to disagreement**
  - Netricity advocates price of $0.36/mcf (Royalty value of $0.15/mcf)
  - Royalty value on current sales of North Slope gas is $1.18/mcf
  - Even if DNR used Netricity's assumed Chicago market price, transmission costs, and discount rate of 10% per year, DNR disagrees with discounting for 18 – 26 years.
  - Discounting over a shorter period provides the following values:

Period (In Years)	10 % Discount Factor[1]	Present Value
0	0.000000	$2.00
1	0.953463	$1.91
2	0.866784	$1.73
3	0.787986	$1.58
4	0.716351	$1.42
5	0.651228	$1.30
6	0.592025	$1.18
7	0.538205	$1.08
8	0.489277	$0.98
9	0.444797	$0.89

[1] Mid-year convention



CORRECTION

THE FOLLOWING DOCUMENT(S)
HAVE BEEN REFILMED TO
ASSURE LEGIBILITY OR PAGINATION

Central Microfilm Services
Department of Education & Early Development
State of Alaska

NETRICITY, continued

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[1] Mid-year convention

Summary of Ongoing Studies and RFPs for Research

In-State Demand Study

- Funded under FY 01 "Fast-track" and proposed governor's office GF, this study will examine:
  - At what price can ANS gas can be delivered to different regions of the state?
  - How much ANS gas can be used in-state if its delivered price can beat the price of existing energy sources (e.g., fuel oil, local sources of gas, coal)?
  - Will new uses of gas arise if ANS gas is available?
- Schedule
  - Proposals Due: July 23, 2001
  - Completion Date: November 2001

Summary of Ongoing Studies and RFPs for Research

Value Study

- Proposed funding under Governor's Office GF, this study will
  - Review the various factors that will impact the calculation of the netback value of ANS gas and identify relevant gas pricing policies and practices used elsewhere
  - Determine methodologies to achieve transparency in netback values and transportaion costs.
- Schedule
  - Proposals Due: July 23, 2001.
  - Completion Date: November 2001.



Summary of Ongoing Studies and RFPs for Research

Supply Study

- Partially funded under FY 01 "Fast Track" Scope of work reduced substantially because additional CIP funds unavailable
    - Independent fieldwork scheduled for Summer 2000 cancelled; Division personnel are now working on reduced fieldwork commitment with DGGS
    - Division of Oil and Gas will complete a hydrocarbon "play" assessment for the North Slope foothills based largely on information we already have.
- Schedule
    - Completion Date: October 2001

Summary of Ongoing Studies and RFPs for Research

Reservoir Study

- Funded under FY 01 "Fast Track" funding. Division will contribute to AOGCC reservoir study.
    - The Division has participated in "scoping" meetings with AOGCC and its reservoir contractor.
    - Our contribution to the AOGCC study will to be to incorporate economic issues.
- Schedule
    - Completion Date: Not yet determined (could be a year-long effort)



STATE FINANCIAL PARTICIPATION – OPTIONS AND ANALYSIS

A. Senate Bill 158 requires the Department of Revenue to submit a comprehensive report by January 31, 2002 to the legislature and the governor addressing the following five issues:

1. Should the State take an equity position in a North Slope gas pipeline project?

2. Should the State participate in financing the project? If yes, under what terms and conditions?

3. If the State participates, will that participation affect the state's ability to provide public services or negatively affect its financial integrity or credit worthiness?

4. Would State participation assist or damage efforts to complete and operate the enterprise?

5. Could or should the State make it possible for individual Alaska residents to become shareholders in the project?

B. Contractors selected and contracts are being completed.

1. CH2 M Hill – David Gray

2. Petrie Perkman – Bill Garner

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2944 SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPLINE, 2001-02

C. Previous studies focused on possible state financial participation in a North Slope Gas Project.

1. Dillon, Reed & Co. 2/15/78 & 3/6/78

2. Three studies prepared by ISER (Arlon R. Tussing and Connie Barlow) for the Alaska Legislature:

   10/25/78
   1/12/79
   4/79

3. Kidder, Peabody & Co. 3/22/82

D. Proponents have said the State should participate financially because:

1. It's likely to be a good deal and the state should share in it.

2. State financial involvement would help the project get done.

3. The producers have too many competing opportunities; the only way the state is ever going to get a project commercializing North Slope gas is to take on the project itself.

4. The State should have a seat at the table because if it does it would learn what's going on in time to protect its interests.

5. **The State should have a seat at the table in order to protect the state's interests. With a seat at the table, the State would be able to exert leverage in the decision-making process to achieve some or all of the following particular policy objectives:**

   a. Route decisions

   b. Local hire/local buy/local build

   c. Gas for communities along the route

   d. Potential gas availability for Southcentral Alaska

   e. Gas for industrial development along the route (e.g. mine development)

   f. Size and pressure configuration that would facilitate petrochemical development in Alaska

   g. Gas liquid availability for a petrochemical industry

E. Opponents have said the State should not participate financially because:

1. State ownership or investment would compromise the main responsibilities we expect of government, environmental protection, health, safety, economic regulation and taxation.

2. State investment would concentrate State "investment" in the oil and gas industry when the State should be diversifying its investments.

3. Governments don't do a good job of running commercial enterprises.

   a. This is generally true throughout the world.

   b. Alaska has had particularly bad experiences.

4. State ownership would involve the pipeline in some levels of the governmental process – both the executive and the legislative – including questions relating to confirmation, annual appropriations, etc.

5. The return to a pipeline would be regulated and not worth the State's investment. The State is likely to earn more by investing the same amount of money through the Permanent Fund.

The Alaska Natural Gas Pipeline

Right-of-Way Permitting for an Offshore Route



John Goll
Alaska Regional Director
Department of the Interior
U.S. Minerals Management Service

Alaska State Legislature
Joint Committee on Natural Gas Pipelines
July 17, 2001

MMS

MMS -- Who We Are

- **Outer continental shelf**
  - oil and gas and other minerals
- **Full complement of regulations**
- **Technical Research Program**
- **Revenues** - collect & distribute
- **Nation's oil and gas production**
  - oil ~25% gas ~ 27%
  - Includes ~ 31,000 miles of pipelines

MMS

2

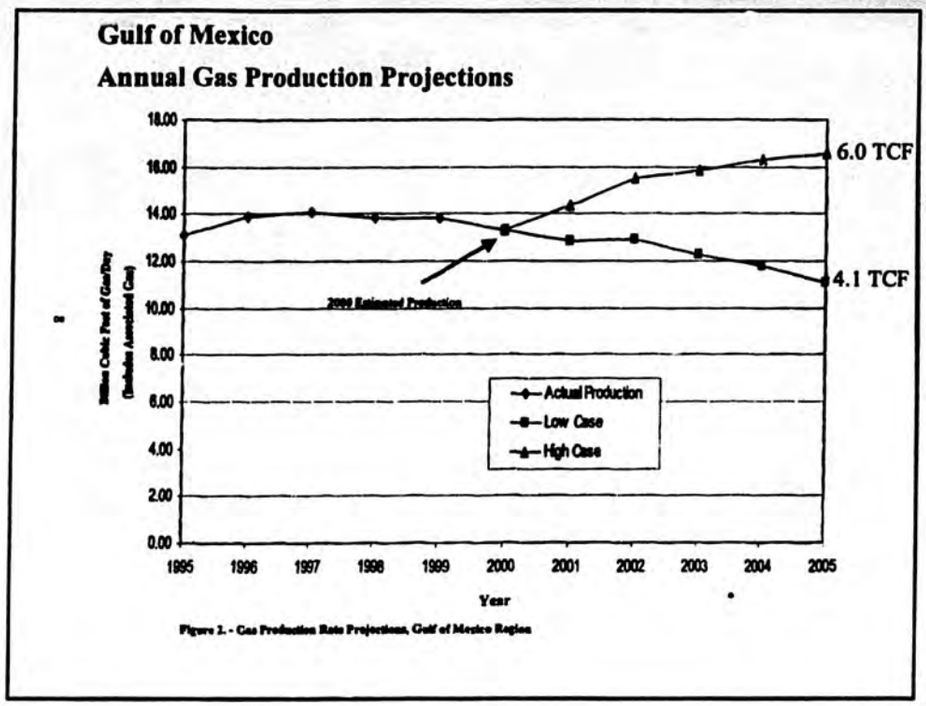
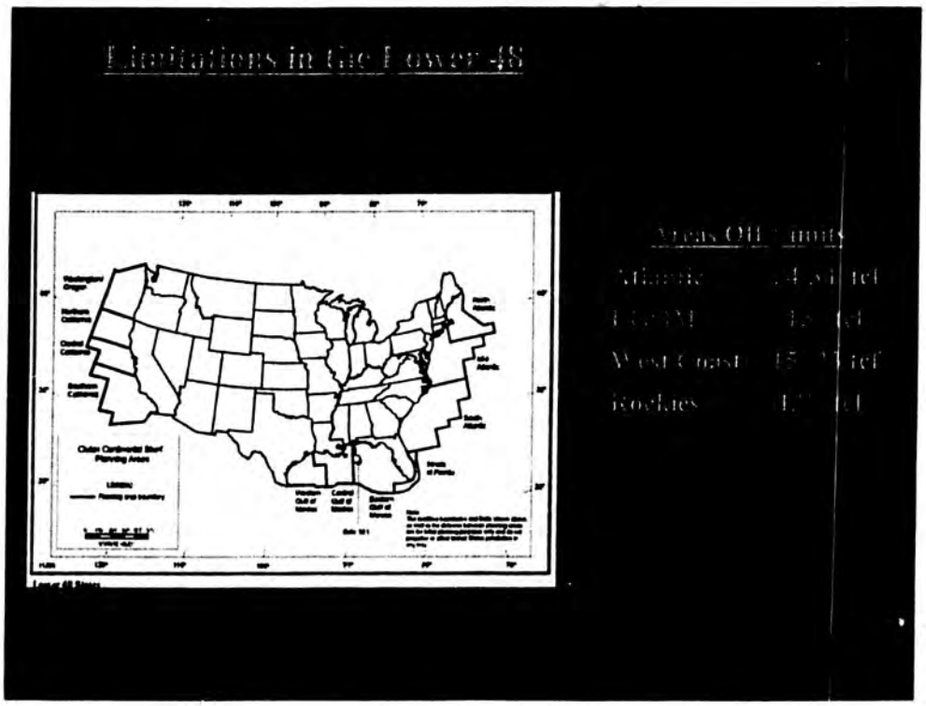


Figure 2. - Gas Production Rate Projections, Gulf of Mexico Region

3



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Alaska OCS Potential

(Risked, Undiscovered, Conventionally Recoverable)
Low to High Estimates

	Oil billions barrels	Gas TCF
• *Alaska OCS Total*	*17 - 35*	*55 - 227*
• Chukchi	9 - 25	14 - 154
• Beaufort	4 - 12	13 - 63
• Hope	0 - 0.3	0 - 11
• Norton	0 - 0.2	0 - 9
• Cook Inlet	0.3 - 1.4	0.7 - 2.5

(MMS 2000 National Assessment)



5

UNDISCOVERED GAS RESOURCES

(mean estimates, TCF)

After MMS [2000], USGS [1995], and Dixon et al. [1994]



Gas Hydrates 170,000 TCF offshore
590 TCF onshore

6

Regulatory Authorities

If an Offshore Route

- **MMS**
  - Right-of-Way Approval
  - OPA Contingency Plan/Financial Responsibility
- **Other Pipeline Agencies**
  - Federal Energy Regulatory Commission
  - State of Alaska Pipeline Coordinators Office (SPCO)
  - DOT/Office of Pipeline Safety (OPS)
- **Canada**
- **Other Agencies**
  EPA, COE, FWS, NMFS



7

?

Regulatory Process

- Pre-application surveys
- ROW application (30CFR250, Subpart J)
  - includes technical, engineering, site specific reviews
- Public review
- NEPA
  - evaluate environmental issues
- CZMA
- Endangered Species Consultation

?

Coastal management program



8

Special Considerations

- Bowhead whales
- Subsistence hunting
- Seasonal construction/repair
- Permafrost
- Ice gouging
- Strudel scour
- Leak detection

MMS

9

during break up - waves will spiral down if it finds a hole

Consultation is Essential

- Many Stakeholders
  - State, Provincial, and Local Governments
  - Federal Agencies (U.S. and Canada)
  - Industry
  - Domestic and international NGO's
  - North Slope Borough government
  - Affected North Slope villages
  - Traditional village governing bodies (IRA)
  - Alaska Eskimo Whaling Commission
  - The public

MMS

10

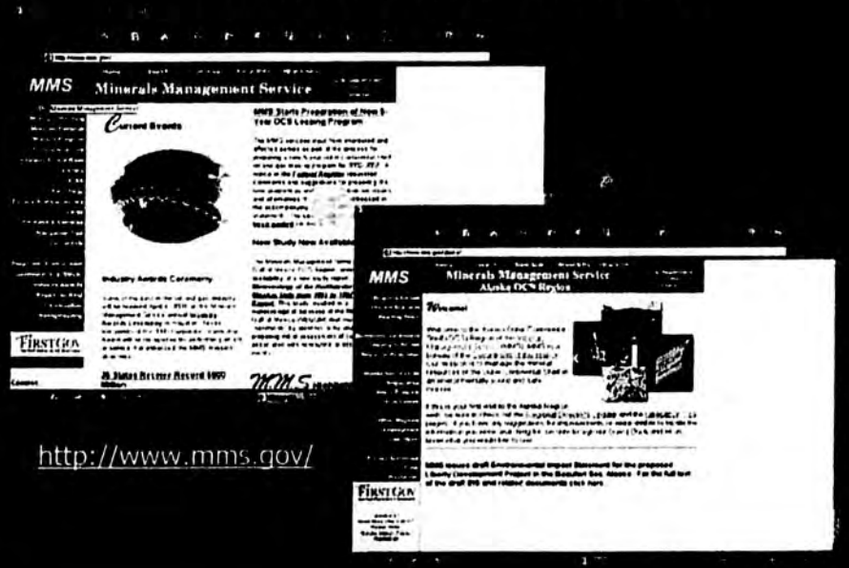
In Conclusion

- Alaska has significant untapped natural gas resources, both now and well into the future
- Right-of-way procedures are available to review an offshore application, if proposed
- We are not advocates for a route
- Regardless of the route chosen, we will assist, if needed

MMS

11

For more information



http://www.mms.gov/

http://www.mms.gov/alaska/

12

Natural-Gas Prices Near 15-Month Lows After Selloff on Milder-Weather Forecasts

COMMODITIES

By Peter A. McKay
Staff Reporter of The Wall Street Journal

NEW YORK—Natural-gas prices fell close to 15-month lows because of forecasts of milder weather in the Midwest and Gulf of Mexico.

Nearby August futures dropped 5.6%, or 18.2 cents, to $3.068 per million British thermal units at the New York Mercantile Exchange. The downgrade of a tropical storm in the Gulf over the weekend helped fuel the selloff, because it eliminated worries of disruption to offshore gas drilling. Also, forecasts that a heat wave in the Midwest this week will be short-lived helped push prices lower, analysts said.

Yesterday's decline was the latest hit for a gas market that has steadily sagged this year on abundant supplies. Since beginning the year at almost $10 per million BTUs, prices have fallen 69%.

The decline in gas prices will be good news for the nation's electricity generators, which in recent years have helped turn the previously winter-oriented natural-gas market into a year-round one with new gas-fired turbines. If a prolonged hot streak causes ratepayers to crank up their air conditioners this summer, it looks like there will be ample natural gas to keep them powered, analysts said.

"It's like the market is in disbelief," said Guy Gleichmann, a senior account executive at trading firm Barkley Financial Group. "You'll get a knee-jerk reaction higher whenever there's another forecast of heat, but until it manifests as lower [inventory], prices are going to be weak."

Gas prices have dropped more than $1 in the past eight weeks alone, as the American Gas Association's weekly storage reports have steadily shown larger increases than analysts expected. The country's total gas inventories now stand at 1.93 trillion cubic feet, up 11.5% from a year ago.

Analysts also said the gas market is "technically weak," meaning that, even independent of supply and demand numbers, trading patterns themselves are helping to push prices lower. For example, large speculators last week unwound 76 "long" positions, or bets that prices would rise, and opened 1,999 "short" positions betting that prices would fall, according to the Daily Energy Hedger newsletter.

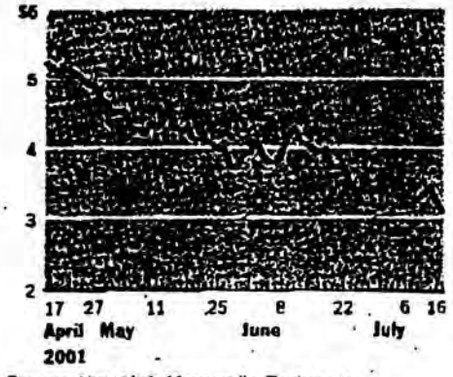
Such a large short position may be hard for some smaller investors to bet against, which only fuels more selling, analysts said.

April 2000 was the most recent time gas closed below $3 at Nymex—a level to which traders believe it could fall again this week.

"After being up to $10 and now down [near $3], it could be significant psychologically, to reach that level," said analyst Phil Flynn of Alaron Trading Corp. "It's great news for California, though, because it helps keep their lights on," he said, referring to that state's power crisis.

Natural-Gas Futures

Continuous front-month contract, in dollars per million British thermal units



Source: New York Mercantile Exchange

Elsewhere in the energy sector, crude-oil prices continued to sag for a sixth straight session. Nearby August futures fell 2%, or 53 cents, to $26.06 a barrel at Nymex.

Analysts said the drop was a continued follow-through from Friday's announcement by the International Energy Agency that it was cutting its 2001 oil-demand growth forecast to 460,000 barrels a day, compared with its original prediction of 1.9 million barrels a day.

"Really, the question of demand goes back to how badly you think the world economy is doing," Mr. Flynn said. "To cut its forecast by 1.5 million barrels, which is a lot of oil, IEA must think things are pretty bad."

In other commodity trading:

GRAINS: Corn and soybean futures prices dropped at the Chicago Board of Trade as U.S. weather forecasts looked more friendly for the crops. November soybean futures fell 14 cents to $5.0875 a bushel and December corn futures fell eight cents to $2.285 a bushel. Last week, the market posted huge gains on fears that hot, dry weather would hurt crop quality. Those fears were tossed aside yesterday amid updated forecasts for less threatening weather for most of the key growing areas, including rain expected across much of the Midwest this week and temperatures forecast below the triple-digits.

SILVER: Futures on silver slid on the Comex division of Nymex on technically oriented selling to close at $4.21 a troy ounce for September, down 9.8 cents. Trader Jim Pogoda at Mitsubishi International attributed the selloff to commission houses but couldn't tell whether they were adding fresh shorts—bets on lower prices—or liquidating long positions. He expected to see buying if a $4.20 price holds. Futures strategist Bill O'Neill at Merrill Lynch saw it headed for $4 to $4.10—the bottom of the range he envisaged—based on the absence of supportive fundamental factors aiding gold.

—David Bogoslaw and Dyanna DeCola contributed to this article.

A partnership between Phillips Alaska, BP, Foothills Pipeline and Marubeni, have just announced Phase II of their feasibility study to build a $ 6 Billion Natural Gas Pipeline. They are considering a Cook Inlet Terminus.

Why Alaskans should support a Cook Inlet Terminus:

1. **70 % of all Alaskans reside and do business on the proposed Cook Inlet route.** Alaskan consumers will have to pay for a costly spur line to connect Alaskans with our Natural Gas.

2. **South Central Alaska's need for Natural Gas is increasing. Supplies are decreasing.** We are facing a serious shortfall.

3. **The Cook Inlet route will protect existing Alaskan Jobs.** Thousands of Alaskan residents work for industries dependent upon Natural Gas. Only the Cook Inlet route will provide the natural gas supplies needed to protect these and other jobs.

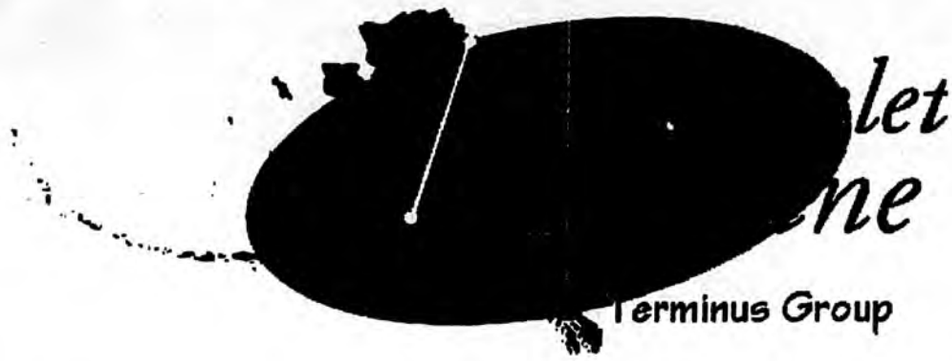
4. **The Cook Inlet route has the space for new industrial growth.** Alaska's Economy needs new industries to expand opportunities, to create quality jobs, to increase the tax base and to build healthy Economic Development. Industry needs room for facilities, storage, housing and support industries. There is plenty of space to grow all along the Railbelt on the route to Cook Inlet.

5. **We support the Midwest/Canadian pipeline, if built in conjunction with an in-state pipeline.** Alaskans should not export economic development with our North Slope Natural Gas. We need more than a handful of short-term construction jobs to build long-term sustainable economic growth.

262-6355 Fax 262-6762

www.alaskagasline.org

Cook Inlet Works Harder for Alaska!



Alaska Natural Gas Pipeline

Promoting a route that serves Alaska

A Cook Inlet Terminus:

- ✓ Will Share Costs with the Midwest/Canadian Pipeline
- ✓ Will Serve Alaskan Natural Gas Consumers
- ✓ Protects Existing Alaskan Jobs & Industries
- ✓ Will Encourage New Business & Industrial Growth
- ✓ For 31 years Liquefied Natural Gas (LNG) has been Safely Produced, Transported on Time and Marketed Successfully and Safely from Cook Inlet.

Cook Inlet Works for Alaska!

www.alaskagasline.org

ALASKA HIGHWAY PIPELINE PROJECT UPDATE

Presentation to the
Alaska State Legislature Joint Committee
on
Natural Gas Pipelines

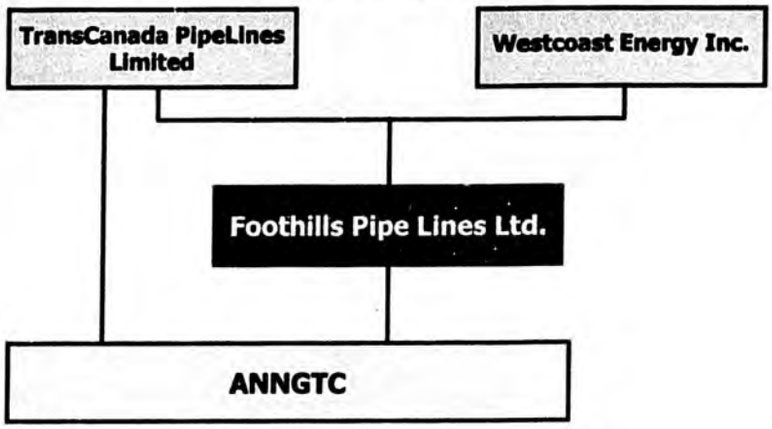
July 18, 2001

Westcoast Energy Foothills Pipe Lines Ltd. TransCanada

Agenda

- Review ANGTS Advantages
- Overview of Alaskan Benefits of ANGTS
- Current Status
- Withdrawn Partners Issue
- Open Access
- Potential State Participation
- Potential Gas Delivery to South Central Alaska
- Path Forward for ANGTS
- Questions and Answers

Alaskan Northwest Natural Gas Transportation Company Corporate Ownership



ANGTS Advantages

- Earliest Timing
- Flexible Framework
- Land Tenure
- Best Route

ANGTS Advantage

Earliest Timing

- ANNGTC/Foothills was selected by the United States and Canada to construct and operate the ANGTS and have secured the following:
  - Federal Lands ROW
  - Federal ROW on State lands
  - FERC Certificate
  - NEB Certificate
  - US Corps 404 permits
  - Yukon ROW
  - British Columbia Map Reserve

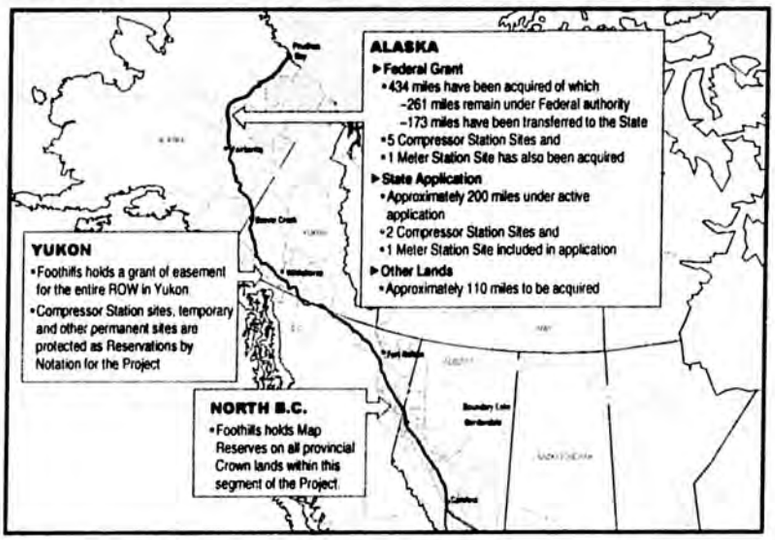
*Each of these components could be expected to require 18 to 36 months to secure **after** a green field application is submitted.*

ANGTS Advantage

Flexible Framework

- The ANGTS framework provides an existing, tested and accepted framework for expediting the delivery of ANS gas to the Lower 48
- Canada has repeatedly reaffirmed its intention to fulfill its commitments reflected in the ANGTS framework
- The ANGTS framework allows for updates to the existing U.S. and Canadian regulatory framework to modify the project, including initial required shipping capacity, the use of updated technology, environmental review, open access and negotiated rate structure
- The ANGTS sponsors are committed to working with the State, ANS producers and other potential shippers to develop a project that achieves the commercial and economic objectives of all parties

Land Tenure



Best Routing

- Best alternative for delivering Alaskan gas to the Lower 48
  - Can be constructed with proven technology
  - Has been extensively reviewed
  - Relies on existing infrastructure
  - Will minimize adverse environmental effects
  - Delivers gas to Alaskan consumers

Best Access to North American Pipeline Grid

- Access to the North American grid enhances the success of the Alaska Highway Pipeline
- Foothills, TransCanada and Westcoast have built and operate most of the gas pipelines in Canada
- Offers expanded market opportunities for Alaska Gas
- Foothills, TransCanada and Westcoast recognized as experienced, reliable and cost effective pipe builders and operators.

Alaskan Benefits

Based on $3 to $5 mmbtu gas price range over 25 years

◆ Increase in Gross State Product	$55 to $122 billion
◆ Increase in employment	26,000 person years
◆ Increase in state and local gov't revenues	$12 to $29 billion
◆ Increase in gross revenues for Alaskan Producers	$36 to $103 billion
◆ Gross revenue gains to Gas Producers through earlier (3 years) connection	$4 to $12 billion

ANGTS Update

- Finalizing state lands right-of-way
- Negotiating a Memorandum of Understanding with Joint Pipeline Office
- Continuing dialogue with:
  - Government officials in Ottawa and Washington
  - Aboriginal Communities
  - ANS Producers
  - ANNGTC Withdrawn Partners

Discussions with Gas Producers/Shippers

- Ongoing discussions with North Slope Producers
- Contact with other interested parties such as exploration and development companies, power generators and power marketers

Discussions With Aboriginal Communities

- Continuing to build upon positive relationships Foothills has developed over two decades
- Building support through discussion of the community benefits of pipeline development

Withdrawn Partners Issue

- ANNGTC Withdrawn Partners have right to recover monies under certain circumstances
- It is recognized that the Withdrawn partners issue needs to be addressed in the overall commercial resolution of this pipeline development.
- This is an issue between ourselves and the Withdrawn partners
- The process to re-enlist Withdrawn Partners has begun and although in the early stages, so far we have seen some encouraging signs.

Open Access

- Alaska's interests best served by continued gas exploration and development
- Access to pipeline vital to E&P activity
- Financing for the initial pipeline will require long-term shipping contracts
- Additional future capacity provided by:
  - Additional compression
  - Looping
  - Combination of both
- Additional capacity will be available to all on an open access basis
- As a pure pipeline service provider, it is in Foothills interests to provide expanded capacity to meet demand

Potential State Participation

- We understand the State is looking at ways to directly participate in a pipeline development
- There are several ways the State could participate in the ANGTS
  - As a lender or guarantor
  - As a shipper
  - As an equity partner
- ANNGTC/Foothills would consider discussion of these or other matters of interest to the State

Gas to South Central Alaska

- Current gas demand in South Central is approximately 220 MMcf per year
- This volume could be delivered via a 16-inch spur line connected to the ANGTS near Fairbanks
- As a pure pipeline service provider, it is in Foothills interests to serve additional supply and market areas whenever it is economic to do so

Path Forward for ANGTS

Foothills

- Continuing to work toward goal of commercial alignment with Producers and potential Shippers
- Finalizing state lands ROW
- Building support in Canada for two stand alone arctic pipelines

Recommendations to Joint Committee

- Publicly encourage gas producers and pipeliners to bring collective strengths to the table and accelerate development of the ANGTS
- Support the conclusion that only ANGTS meets the Governor's goal of earliest possible start for the pipeline project

Alaska Conservative Union Fitz Fachetti

The following are potential causes of action followed by a short informal discussion of the basic issue.

I. Article VI, Section 6. Alaska Constitution. Compact, Contiguous, Socio-economic Integration.

1. Linking Valdez with Anchorage in House District 32 violates the constitutional requirement that districts be formed of compact territory containing as nearly as practicable a relatively integrated socio-economic area.

Contiguity, compactness and relative socio-economic integration are constitutional requirements. *See Kenai Peninsula Borough v. State*, 743 P.2d 1352, 1360-61 (Alaska 1987) ("The state must consistently enforce the constitutional article VI, section 6 requirements of contiguity, compactness, and relative integration of socio-economic areas in its redistricting."). A district lacking any one of these characteristics may not be constitutional under the Alaska Constitution. *Hickel*, 846 P.2d 38 (1992).

Inherent in the concept of geographical legislative districts is a recognition that areas of a state differ economically, socially and culturally and that a truly representative government exists only when those areas of the state which share significant common interests are able to elect legislators representing those interests. Hickel, 446 P.2d 38 (1992).

2. The Southern Extension of House District 16 (Chugiak) into House District 17 (Eagle River) violates the constitutional requirement that districts be formed of compact territory.

The requirements of contiguity, compactness and socio-economic integration were incorporated by the framers of the reapportionment provisions to prevent gerrymandering. 3 PACC 1846 (January 11, 1956). Gerrymandering is the dividing of an area into political units "in an unnatural way with the purpose of bestowing advantages on some and thus disadvantaging others." *Carpenter v. Hammond*, 667 P.2d 1204, 1220 (Alaska 1983) (Matthews, J., concurring). Likewise, appendages attached to otherwise compact areas may violate the requirement of compact districting. *Hickel*, 846 P.2d 38 (1992).

House District 16 makes an un-natural extension into House District 17, which results in the pairing of two incumbents. The record demonstrates a more compact alternative was available.

3. House District 12 (Rural Mat-Su) violates the constitutional requirement that districts be formed of compact territory containing as nearly as practicable a relatively integrated socio-economic area.

See above. Board ignored testimony from Mat-Su and combined areas in District 12 (rural Mat-Su) that have virtually no economic integration (*i.e.*, separating Talkeetna and the Parks Hwy. from Houston, Willow, Big Lake and placing them with Butte, Lazy Mountain and Chikaloon).

4. House Districts 2 and 5 (Southeast Islands District) violates the constitutional requirement that districts be formed of compact territory containing as nearly as practicable a relatively integrated socio-economic area.

The Board initially drafted a plan that would split the "ice worm" district into two separate, more compact districts. Members of the Board, including Republican appointees, changed their mind based upon public testimony that linking the smaller communities of the "island district" into one long district would provide better representation to the communities of both House District 2 and 5. Members of the Board, as well as their attorney, voiced concern recognizing that the initial draft provided more compact districts.

II. Article I, Section 1. Alaska Constitution. Equal Protection.

1. **Over-representing the Anchorage Municipality by 10% in House District 32 reduces the proportional representation outside the Municipality thereby diluting a geographic area's voting strength and violating the Equal Protection Clause of the Alaska Constitution.**

"In the context of reapportionment, we have held that upon a showing that the Board acted intentionally to discriminate against the voters of a geographic area, the Board must demonstrate that its plan will lead to greater proportionality of representation." *Kenai Peninsula Borough*, 743 P.2d at 1372. Because of the more strict standard, we do not require a showing of a pattern of discrimination, and do not consider any effect of disproportionality de minimis when determining the legitimacy of the Board's purpose. *Id.*

Anchorage population supports 16.61 house seats. The Board's plan gives Anchorage 16.709 House Seats. The decision to over-represent Anchorage is not justified by any State, Federal redistricting requirement and has the effect of diluting the impact of voters outside the Municipality.

2. **The application of strict proportionality to the Anchorage Municipality while applying a majority control test to the Matanuska-Susitna Borough violates the Equal Protection Clause of the Alaska Constitution.**

The interest asserted is the right to an equally powerful and geographically effective vote in the state legislature. In this connection we note that it is implicit in our constitutional structure that similarly situated communities be treated in a similar manner. *Kenai Peninsula Borough v. State*, 743 P.2d 1352 (1987).

The Board based its decision to couple South Anchorage with Valdez on the requirement that Anchorage must receive the full 16.6 seats its population supports, a theory of strict proportionality. However, the Board never attempted to provide Mat-Su its full representation. When referencing Mat-Su, the Board spoke in terms of "control", and interpreted this to mean that Mat-Su only had to have more than 3.51 House seats to control a legally sufficient number of seats. The record demonstrates that an alternative plan could easily be devised to increase the proportionality of the Mat-Su. The increase in Mat-Su's proportionality is directly linked to Anchorage only receiving it's 16.6 as opposed to 16.7 seats. The House numbers for Anchorage and Mat-Su are as follows:

Mat-Su – Entitled to 3.784 House seats. Received 3.633. 15% short geographic Proportionality.

Anchorage – Entitled to 16.607 House seats. Received 16.709. 10.9% above geographic proportionality.

Anchorage and the Mat-Su together deserve 50.7% of all House seats. Anchorage Mat-Su received 21 seats or 52.5%. If Anchorage and Mat-Su shared a seat they would have received 20 total seats or 50%, which is a better proportional representation overall.

3. **Pairing Mat-Su Senate Districts outside the Borough is not required, and fails to achieve geographic proportionality and thus violates the Equal Protection Clause of the Alaska Constitution.**

A municipality should not be made to contribute so much of its population to districts centered elsewhere that it is deprived of representation which is justified by its population. Hickel. Mat-Su is entitled to 1.89 Senate seats and should receive almost two complete Senate districts wholly within the borough boundary. Mat-Su received one Senate seat wholly within the borough. Mat-Su shares a second Senate seat with Anchorage, 52% being within the Mat-Su and 48% being in Anchorage. This seat is considered a "controlled by Mat-Su" seat and accepted by the Board as meeting the Mat-Su's deserved representation. The result is Mat-Su is 37% short of geographic proportionality. Mat-Su shares a third Senate seat with Fairbanks, Denali Borough, and Rural Richardson Hwy. Mat-Su has 31% of this Senate seat and will not control.

In contrast Anchorage deserves 8.3 Senate seats. By pairing with Mat-Su, Anchorage controls 8 seats and receives 48% of a ninth for 18% over-representation (7 Senate seats wholly within Anchorage, 1 Shared with Valdez giving Anchorage 85.4% of the Senate district, and 1 shared with Mat-Su giving Anchorage 48% of the seat).

The Board could have given Anchorage and Mat-Su geographic proportionality by pairing House District 32 (Anch.-Valdez) south to the Kenai, a traditional pairing, or the Southeast Islands District. The Board did not pursue a southern pairing because the result would have forced District 6 (Interior Rivers) to pair with Fairbanks as Fairbanks has five seats and is only contiguous with Mat-Su or Interior Rivers. Interestingly the Dist 6-Fairbanks pairing was the pairing in the original AFFR plan but was changed at the request of the incumbent native senator from Dist 6.

4. **Splitting excess Kenai Borough population between two separate House districts violates the Equal Protection Clause of the Alaska Constitution.**

We recognize that it may be necessary to divide a borough so that its excess population is allocated to a district situated elsewhere. However, where possible, all of a municipality's excess population should go to one other district in order to maximize effective representation of the excess group. This result is compelled not only by the article VI, section 6 requirements, but also by the state equal protection clause which guarantees the right to proportional geographic representation. *Hickel.*

The Board split the Kenai Borough twice giving Tyonek to House District 6 (Interior Rivers) and Hope to House District 32 (Anchorage-Valdez). Kenai supports approximately 3.2 seats.

Alaska State Legislature

Joint Committee on Natural Gas Pipelines

July 17, 2001

Anchorage Alaska

CERA

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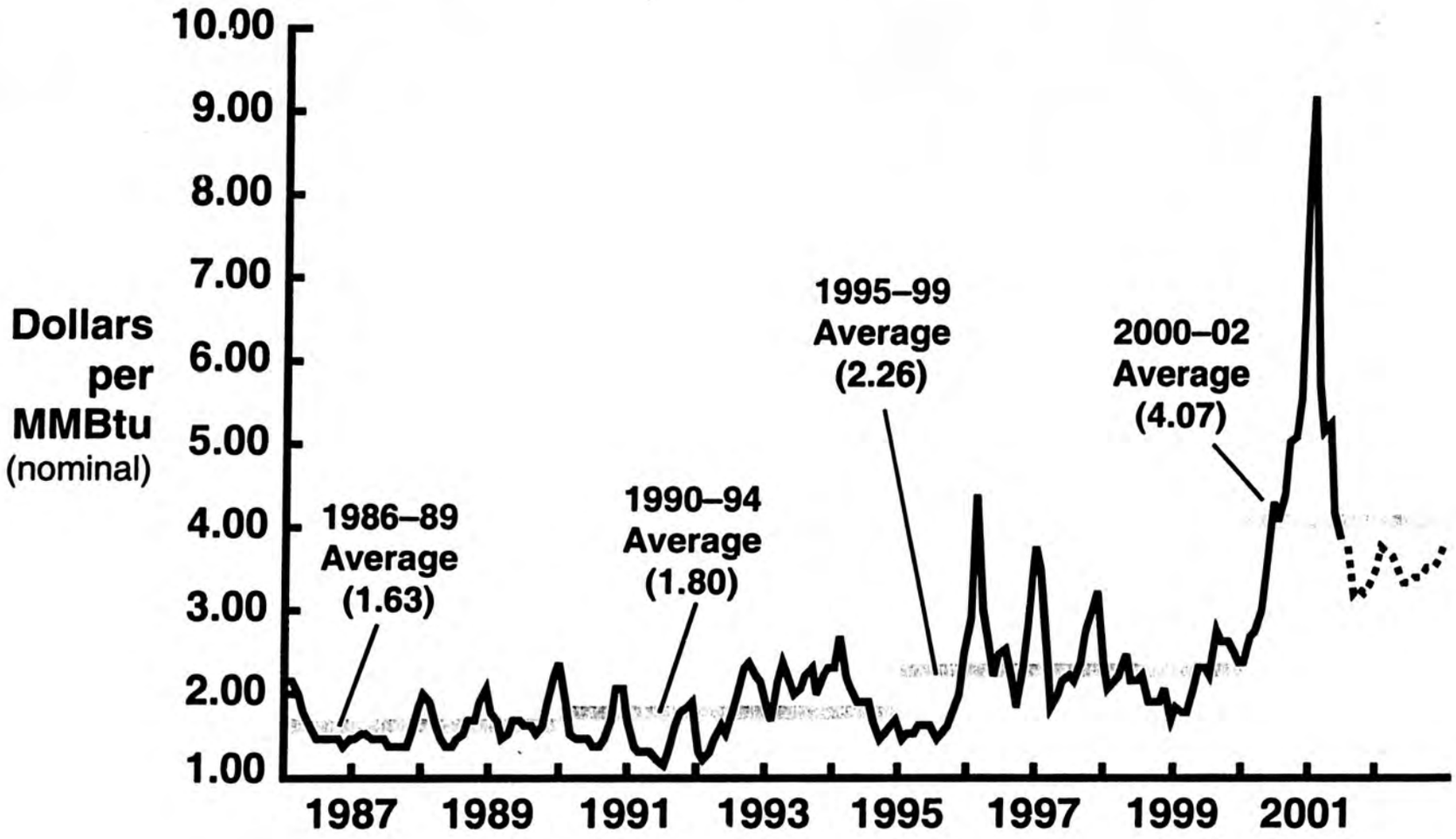
The Surge in North American Gas Prices (Henry Hub Spot Price)



Source: Cambridge Energy Research Associates.

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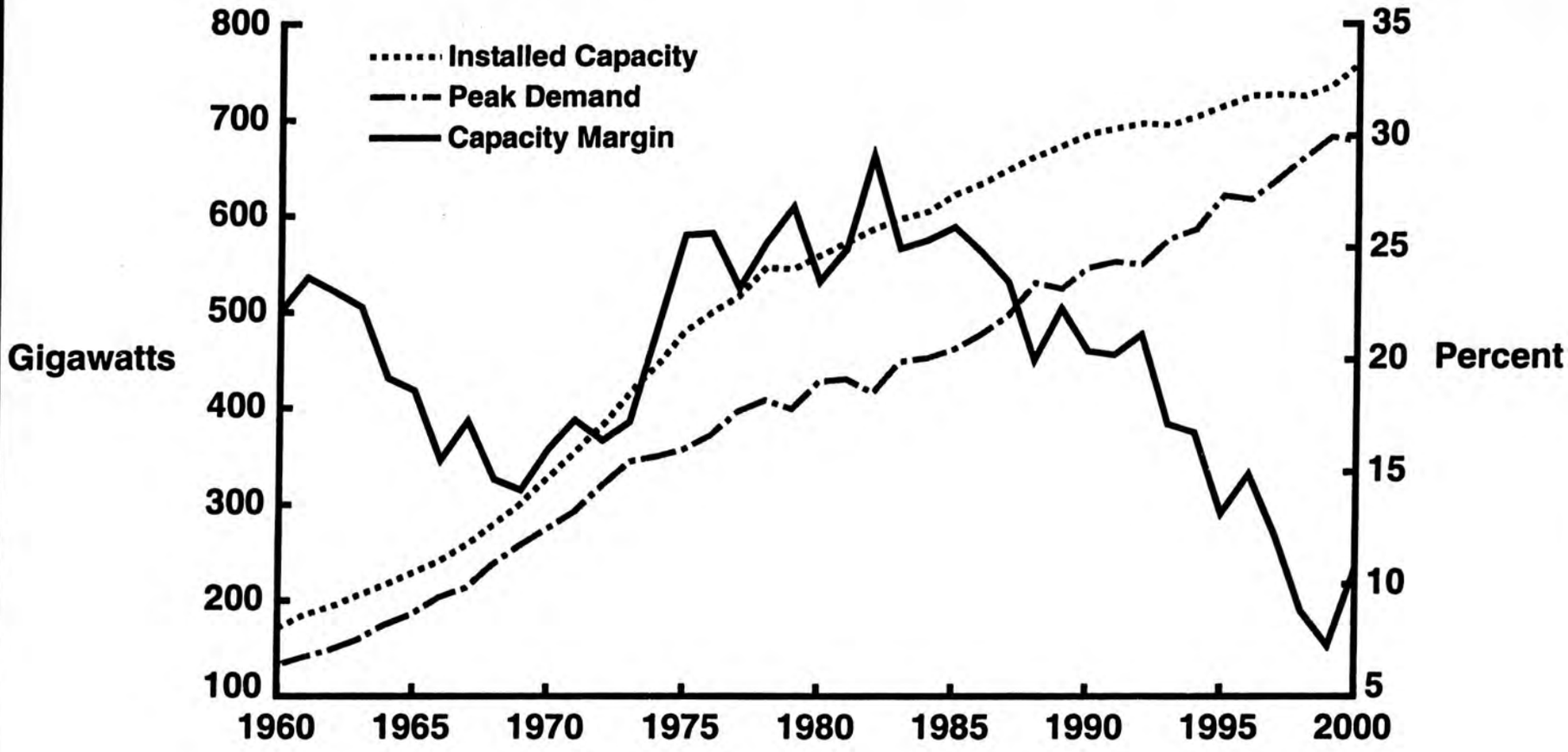
US Installed Capacity, Peak Demand, and Capacity Margin



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Source: Cambridge Energy Research Associates.
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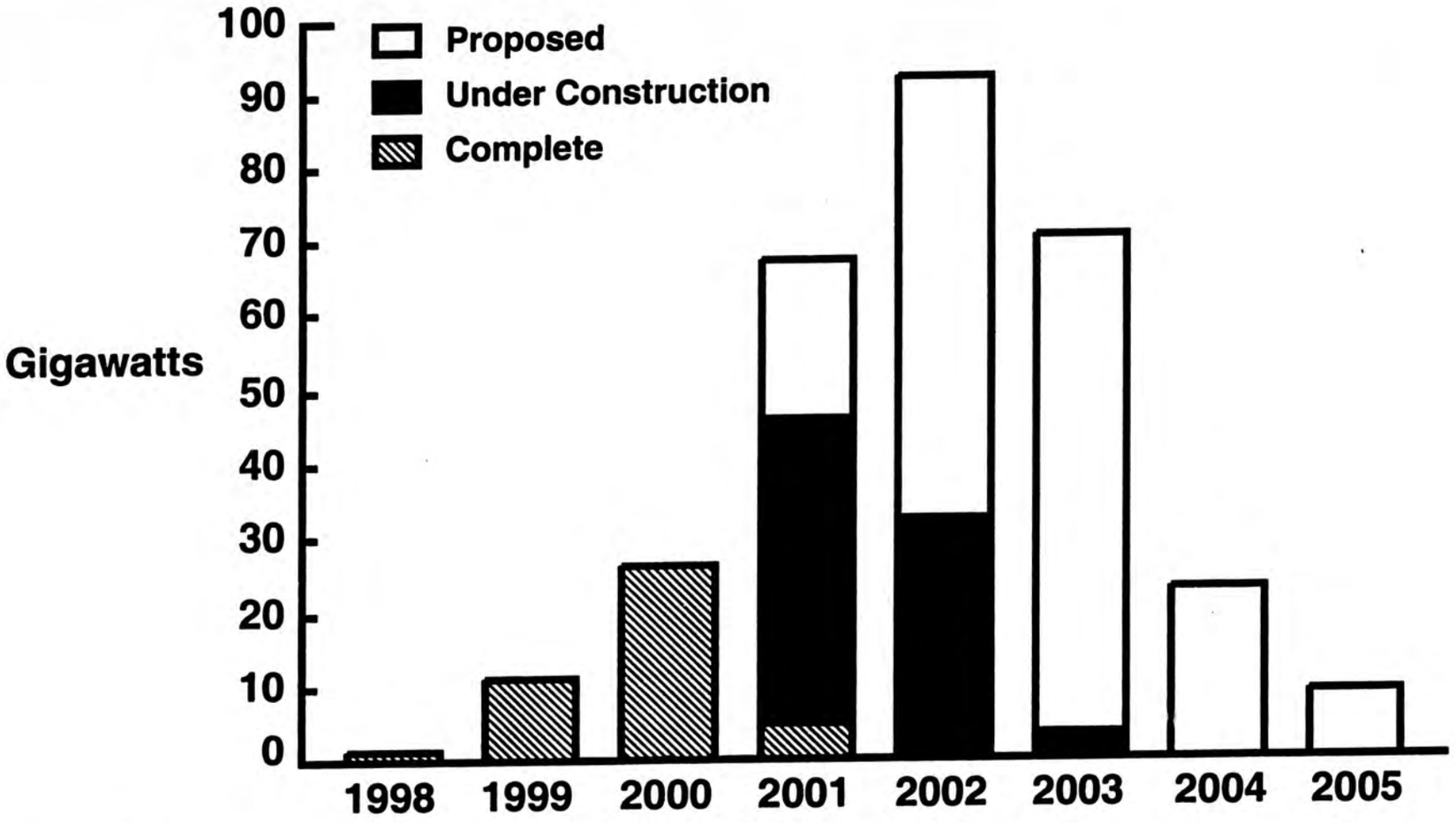
North American Generation Project Status



Source: Cambridge Energy Research Associates.
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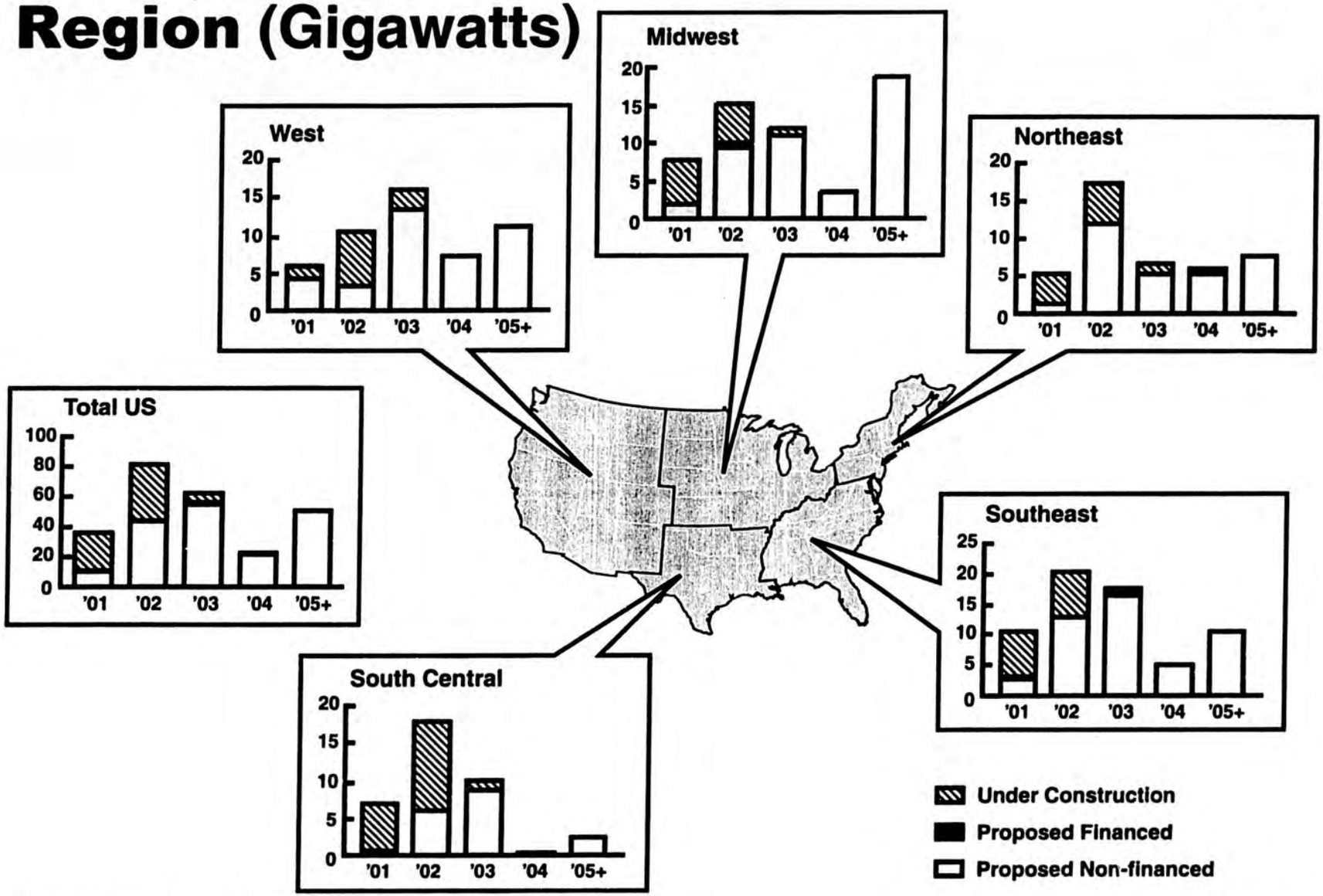
Pressure in the Pipeline: The Potential Gas-fired Power Build by Region (Gigawatts)



Source: Cambridge Energy Research Associates.

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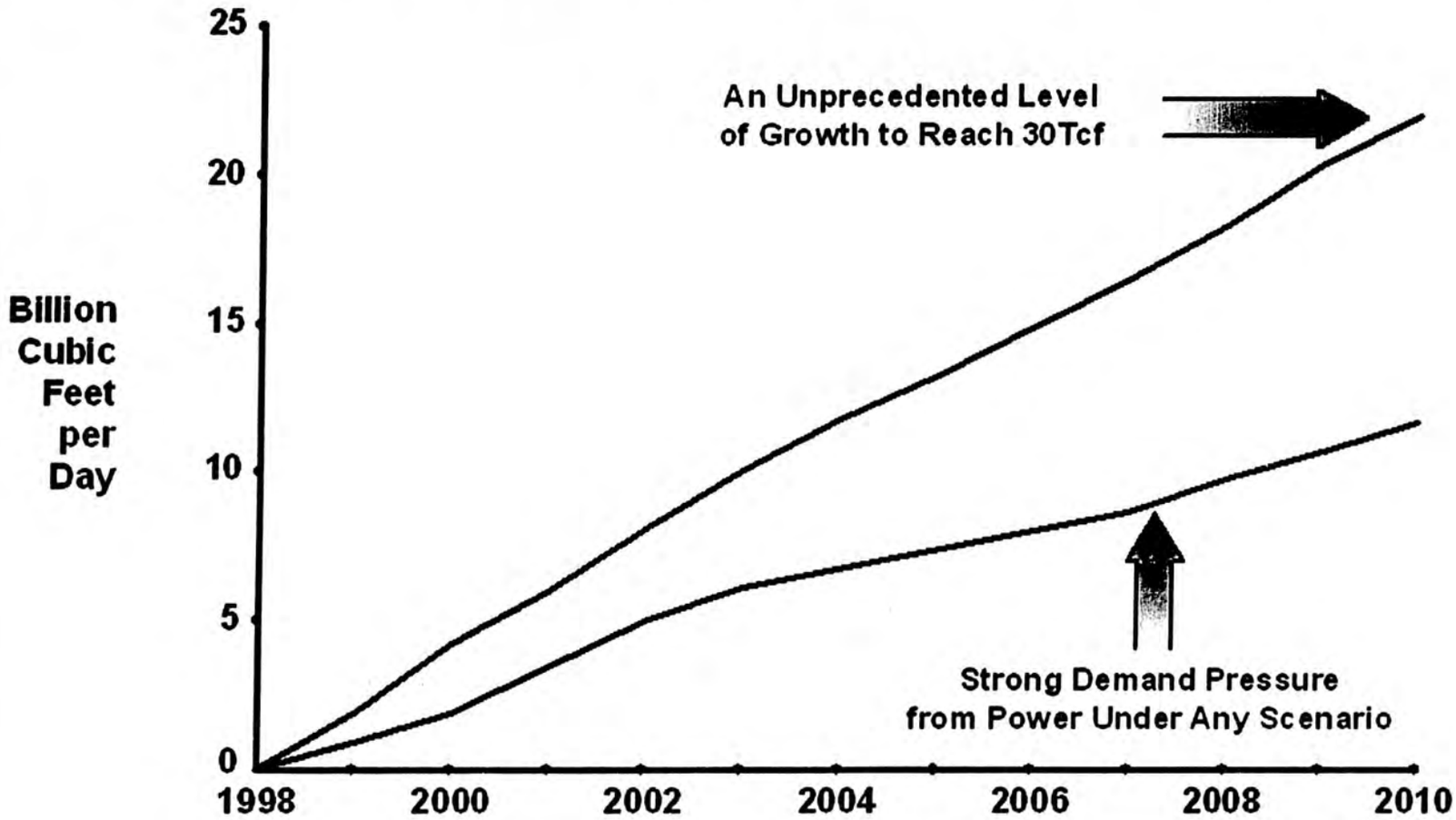
30 Tcf: More Plausible Than Probable The Range of Natural Gas Demand Growth Relative to 1998



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Source: Cambridge Energy Research Associates.

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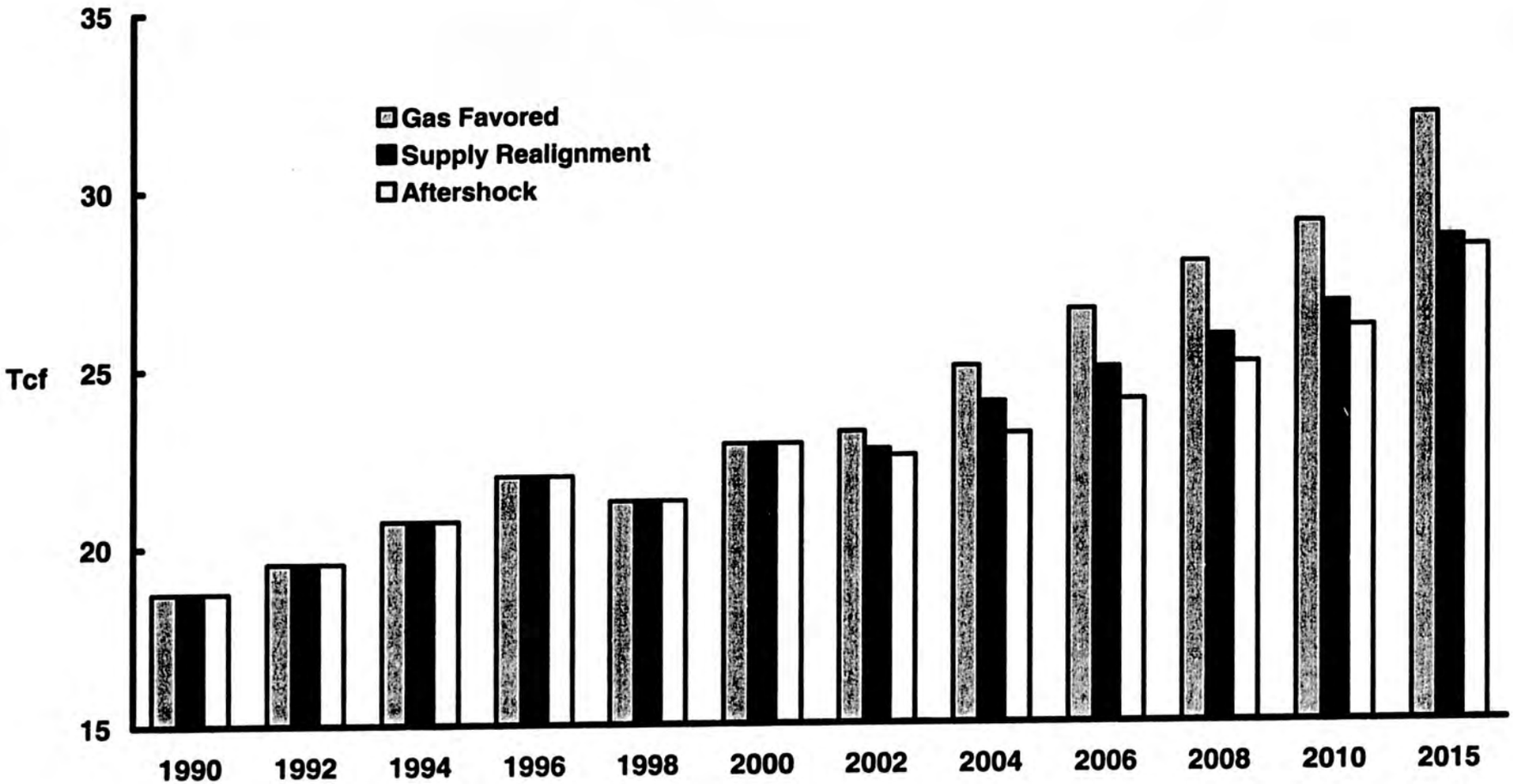
US Lower-48 Natural Gas Demand



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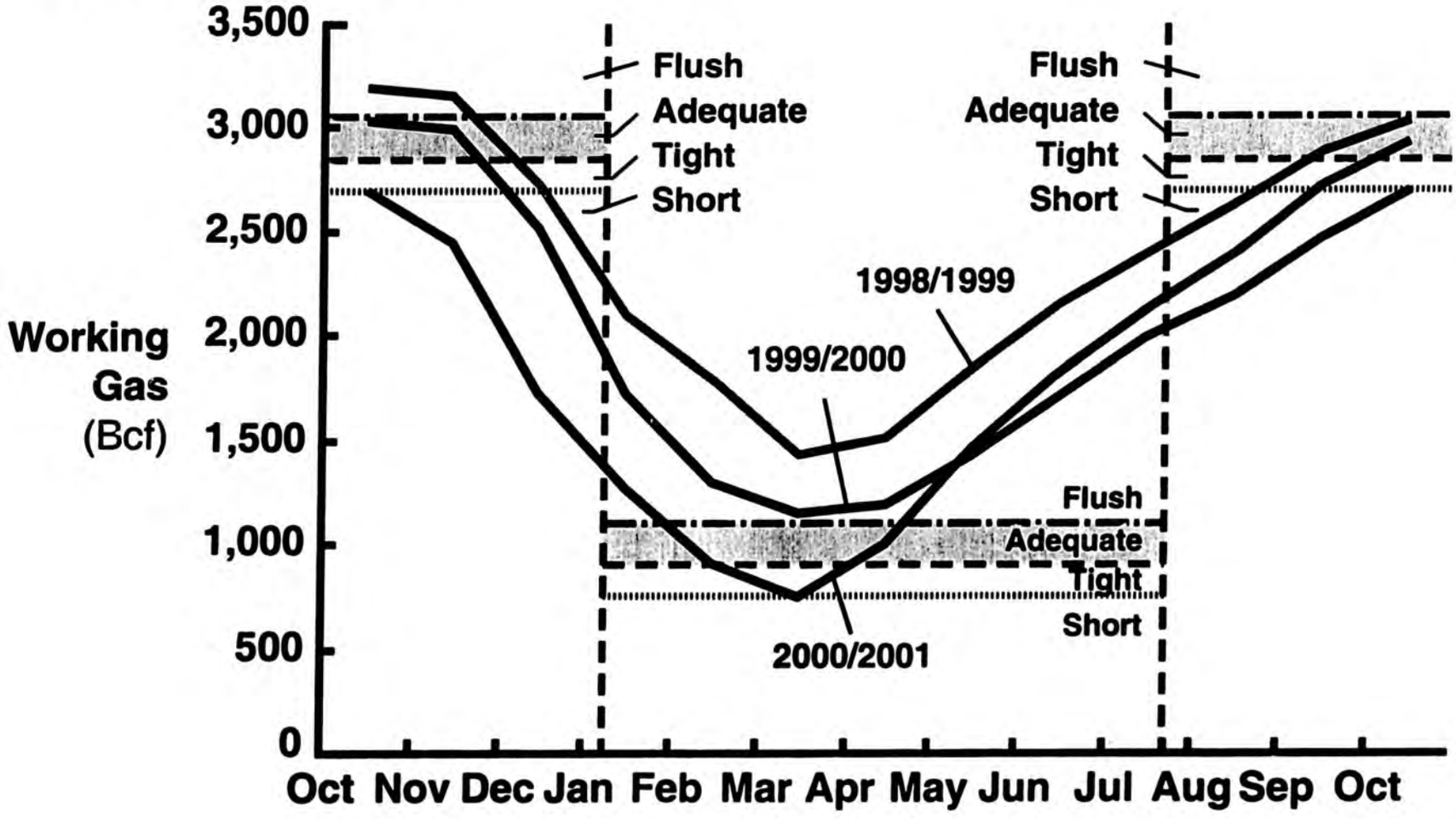
The Storage Cushion Deflates: Supply Declines Drive Down Inventories



Source: Cambridge Energy Research Associates.

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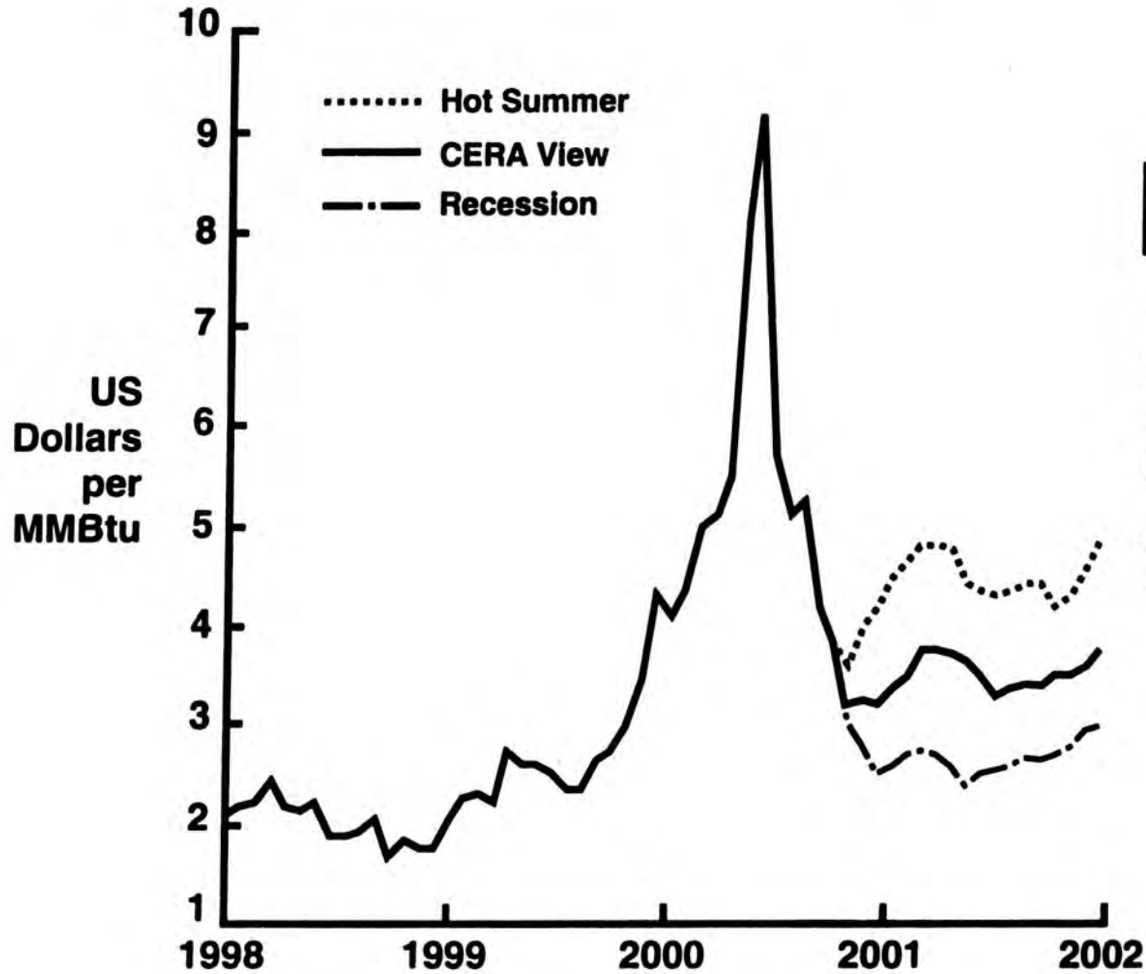
Henry Hub Price Projections



	2000 Average	2001 Average	2002 Average
Hot Summer:	$4.23	$4.91	$4.46
CERA View:	$4.23	$4.45	$3.53
Recession:	$4.23	$4.13	$2.68

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Source: Cambridge Energy Research Associates.

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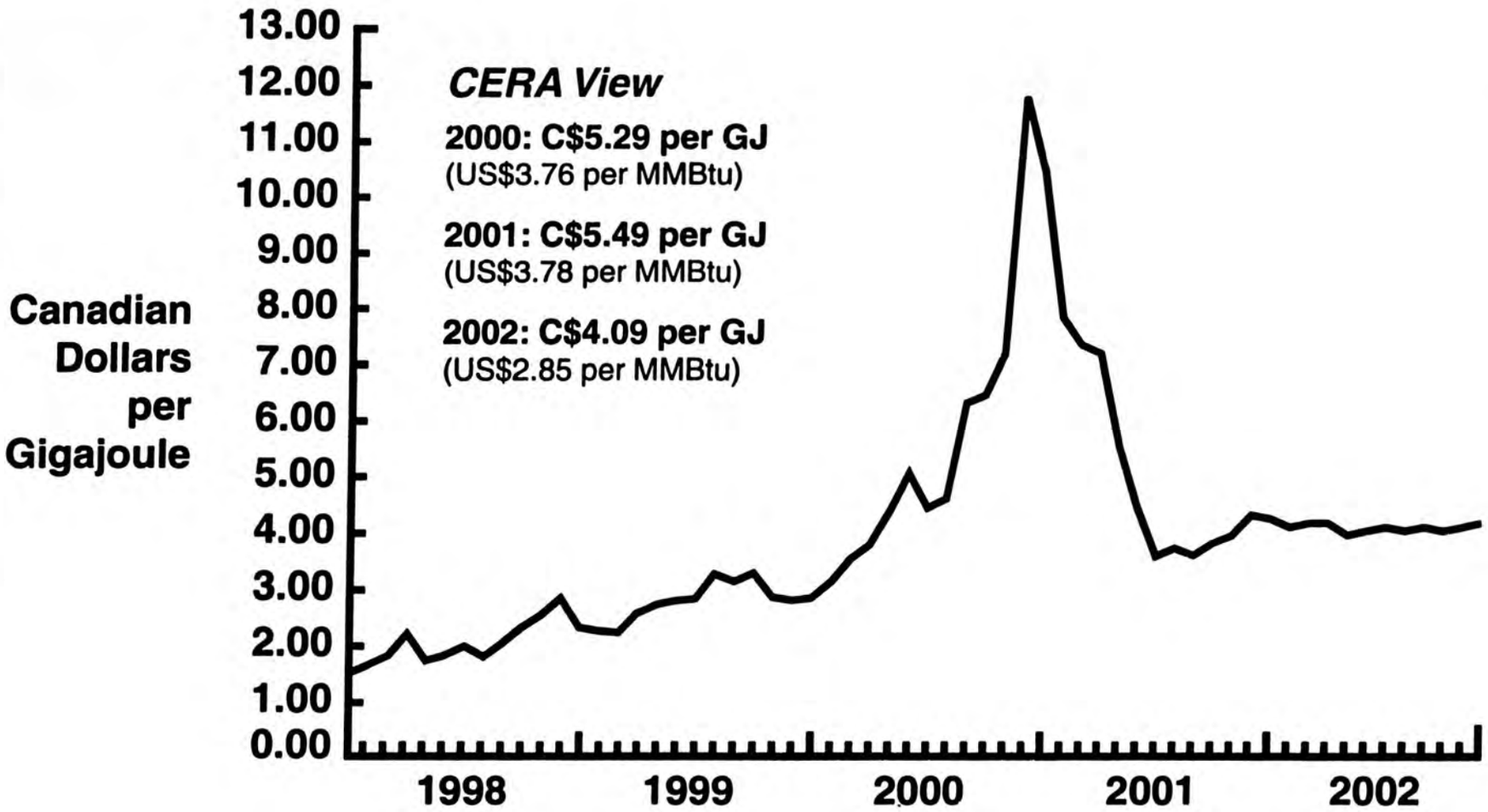
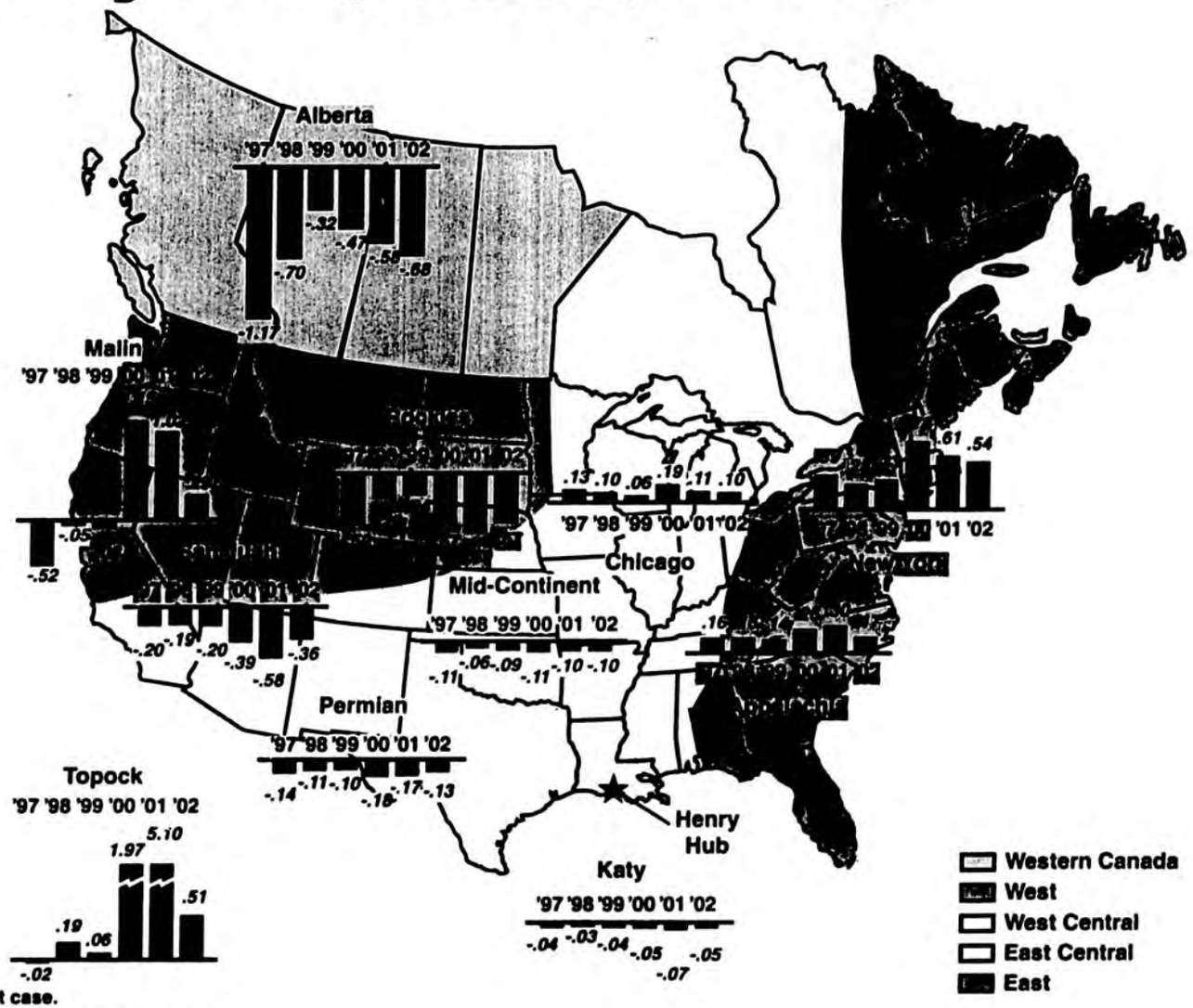
070501

AECO Spot Gas Price Outlook



Source: Cambridge Energy Research Associates.

Natural Gas Key Regions of Basis Differentials: Price Differentials to Henry Hub (US dollars per MMBtu)



Note: Supply Realignment case.

Source: Cambridge Energy Research Associates.

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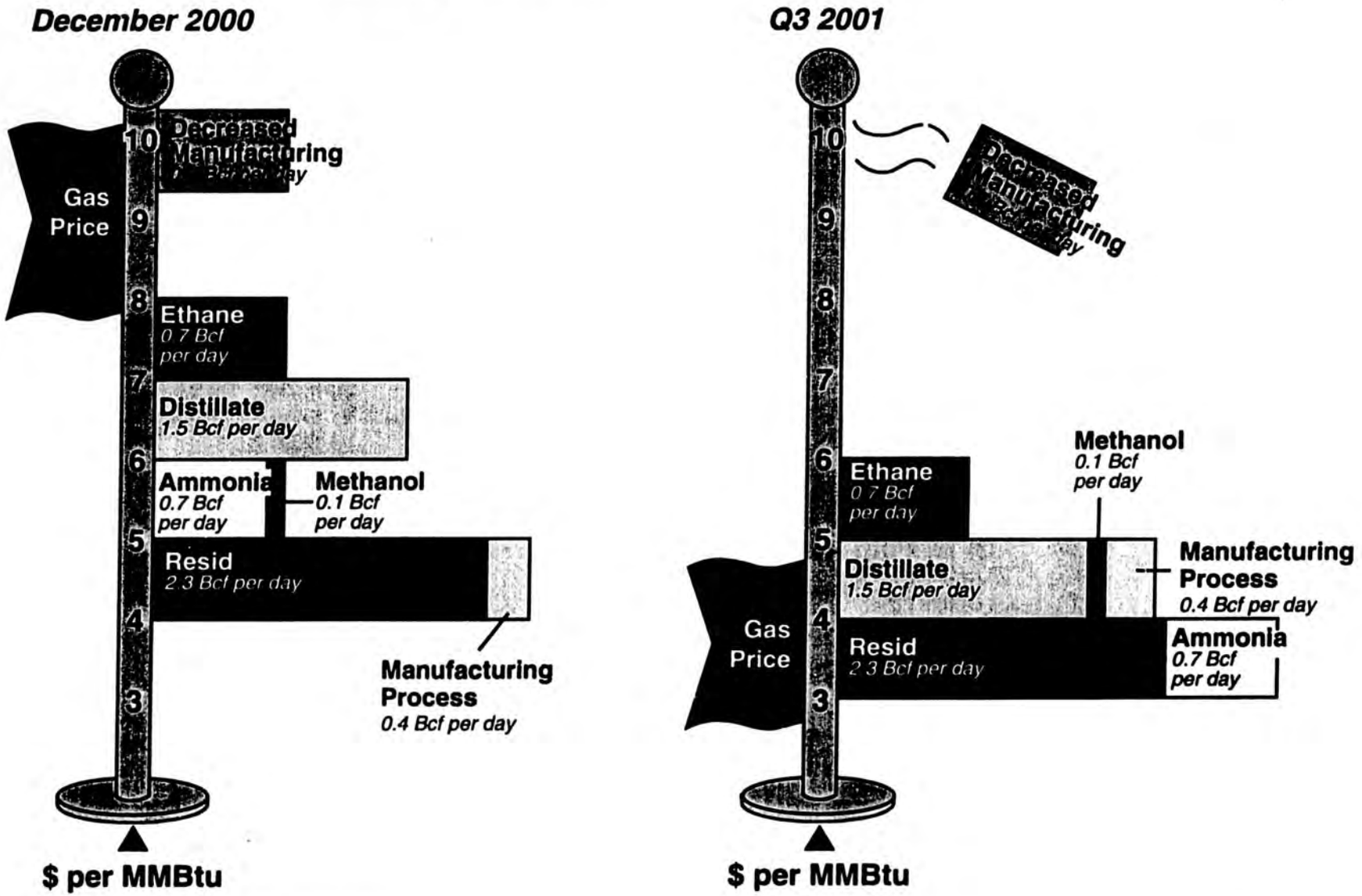
Shifts in Competitive Markets



Source: Cambridge Energy Research Associates.

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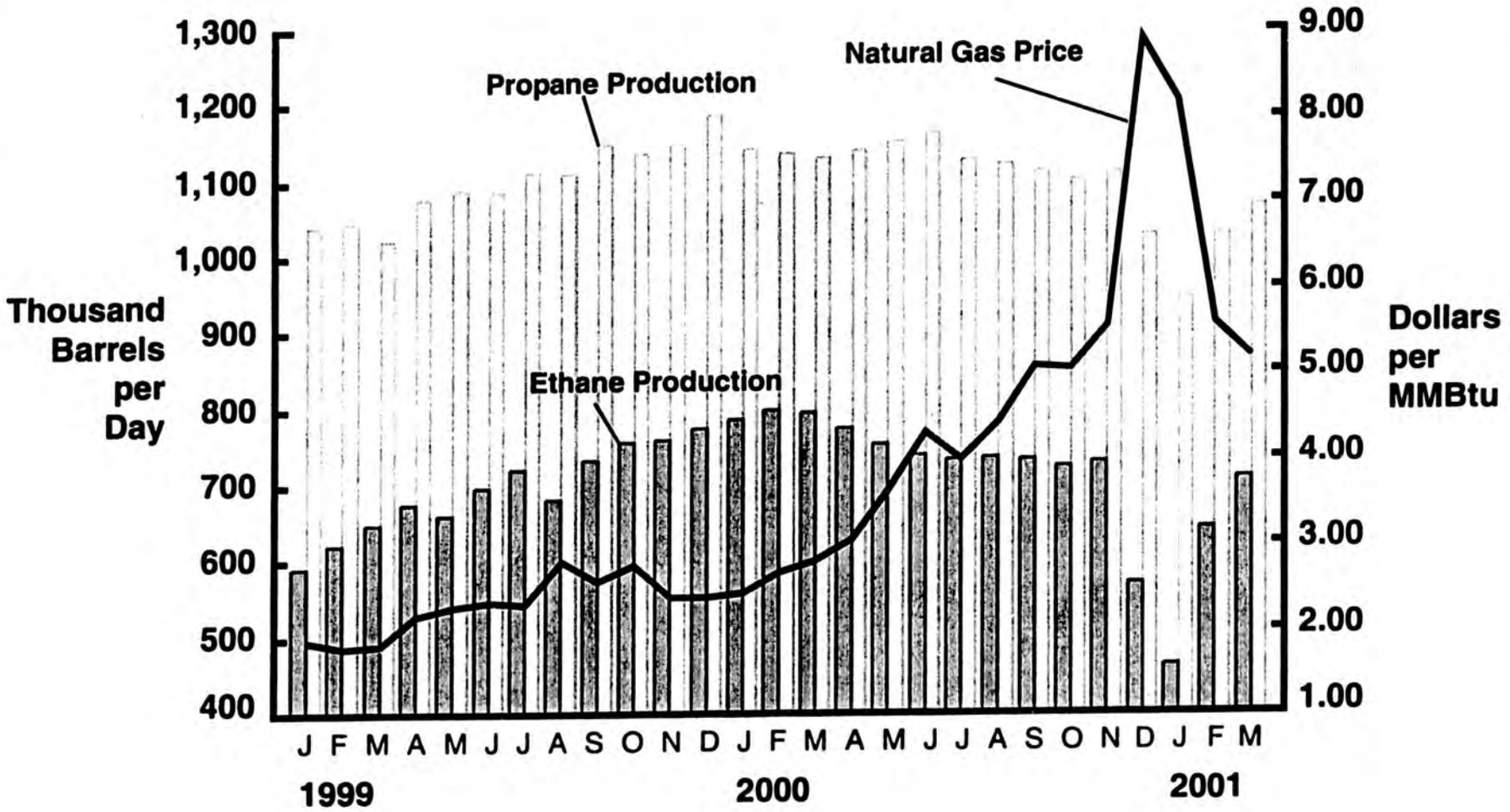
US Gas Liquids Production versus Natural Gas Price



Source: Cambridge Energy Research Associates.

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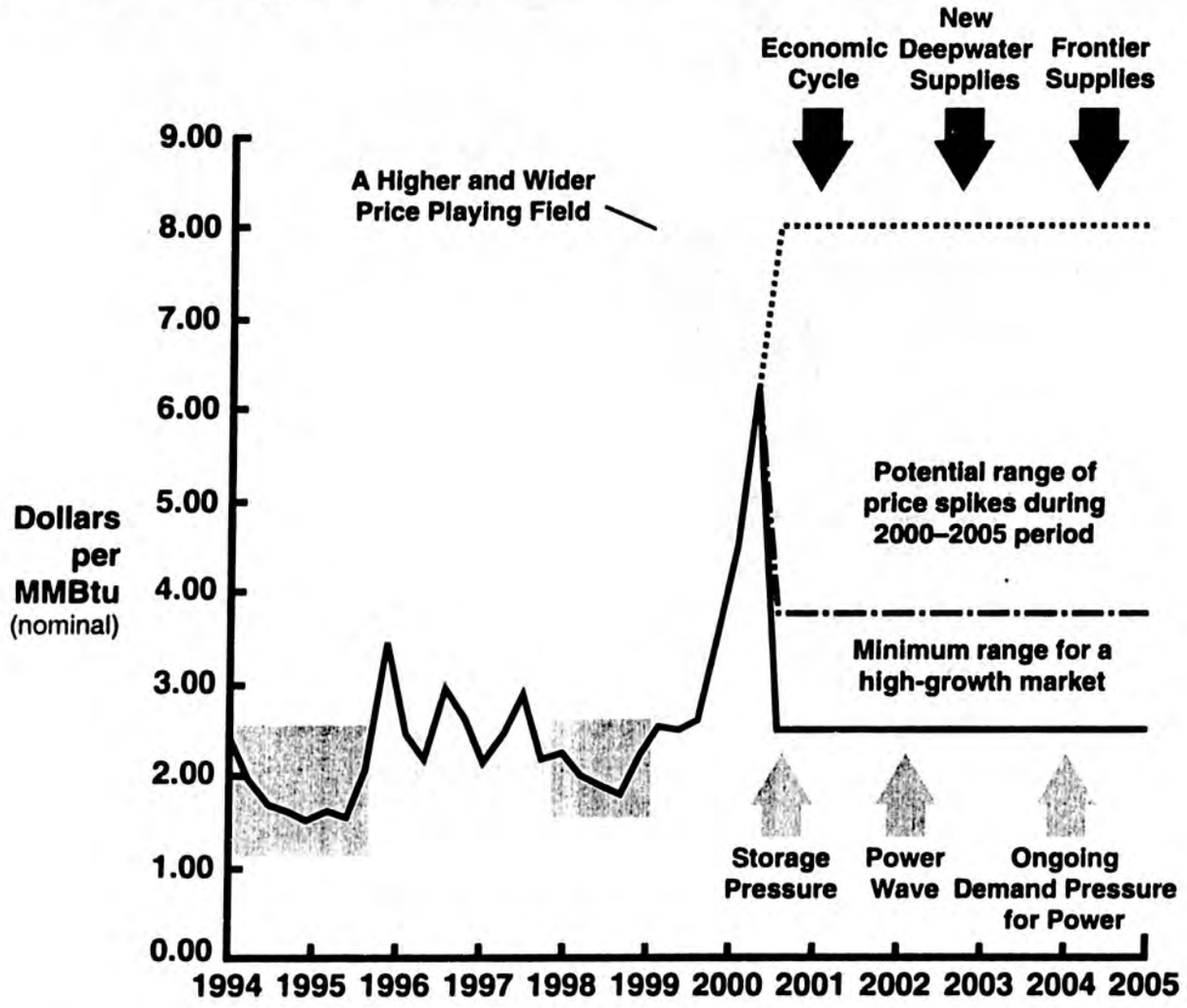
NATURAL GAS MARKETS: Are We Headed for an Extended Boom/Bust Cycle in 2000–2005?



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Source: Cambridge Energy Research Associates.

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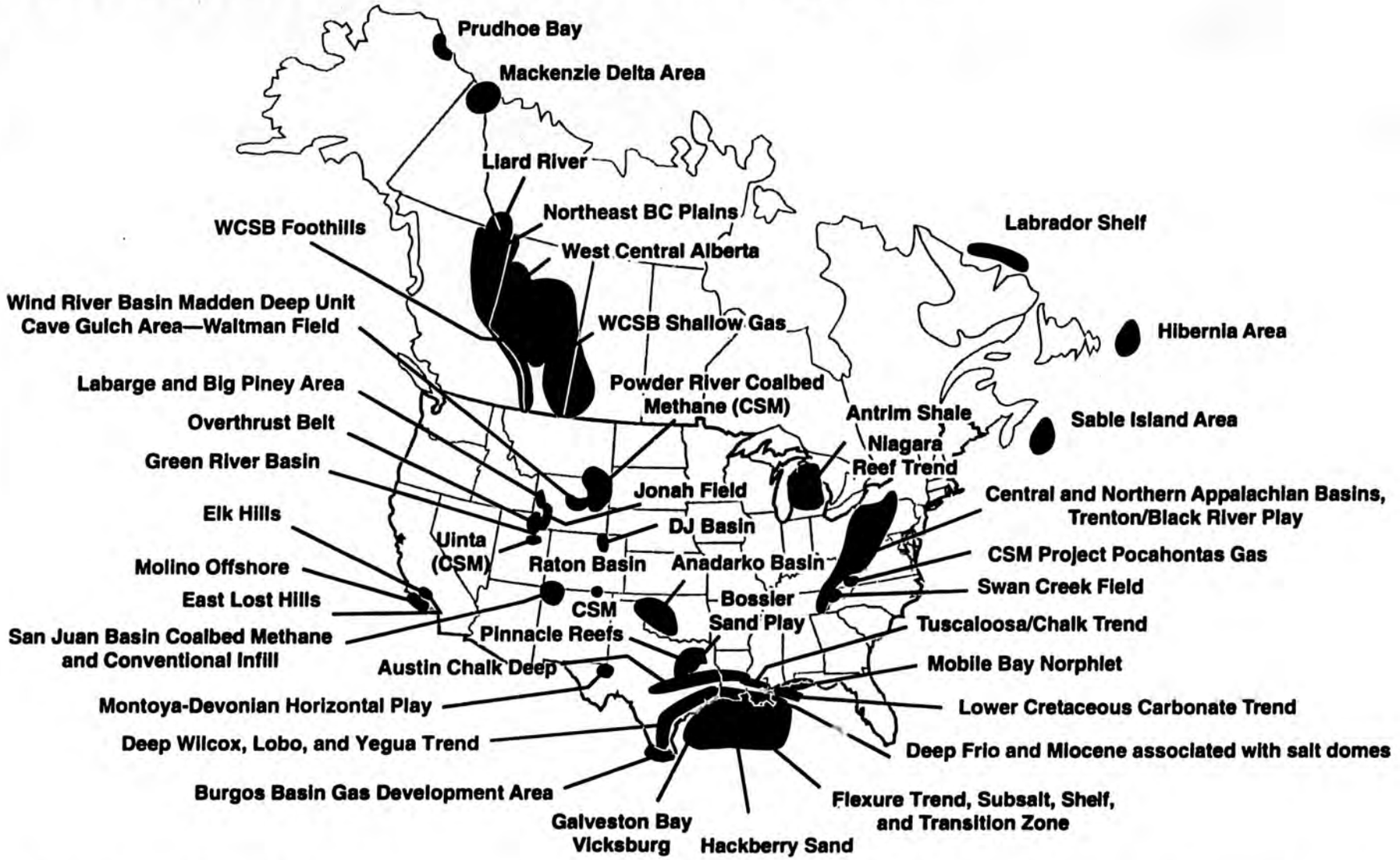
0220

Note: Henry Hub spot price as reported in Natural Gas Week.

Major North American Gas Exploration and Development Hotspots



CERA

Source: Cambridge Energy Research Associates.
Updated April 2001

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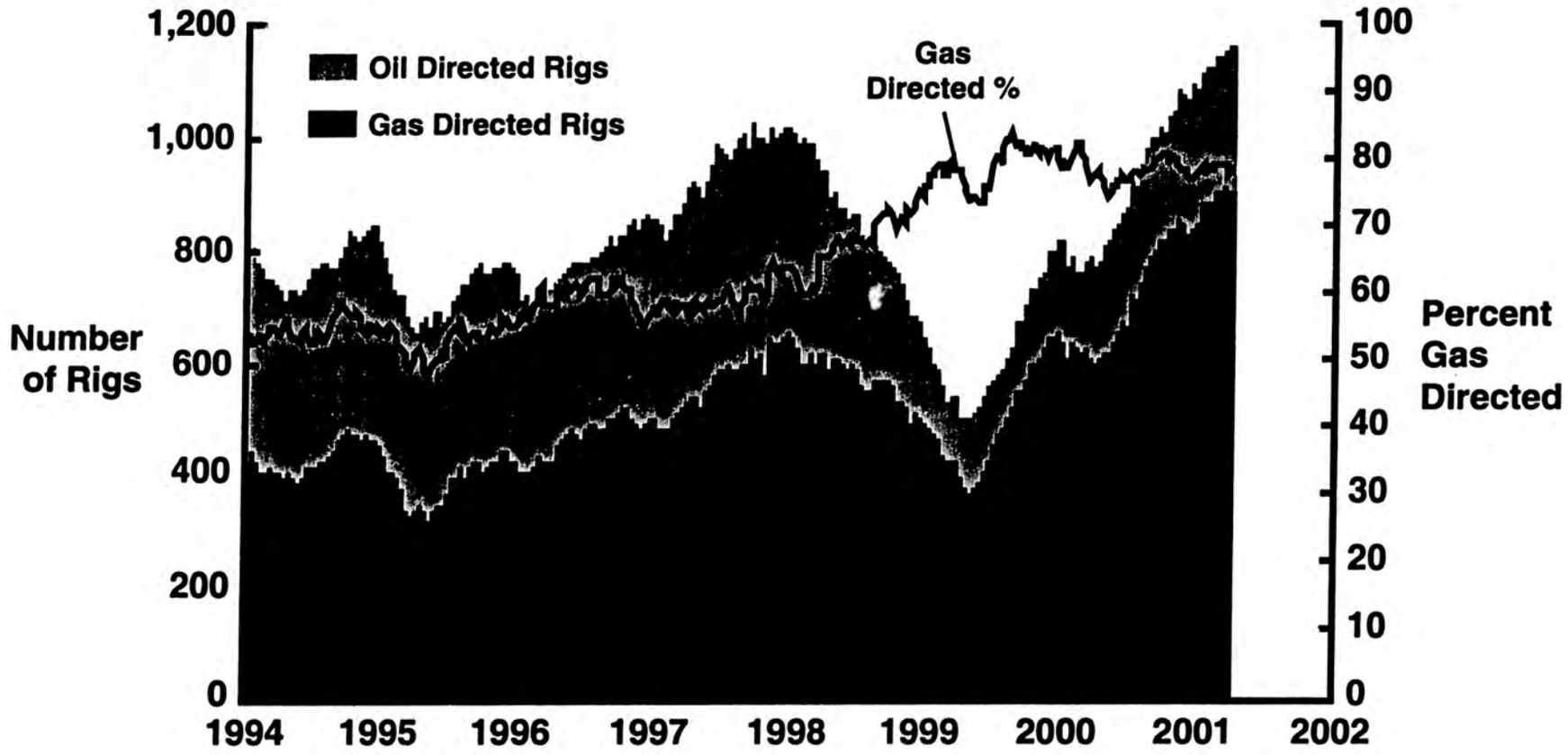
US Rig Fleet and Gas-directed Drilling



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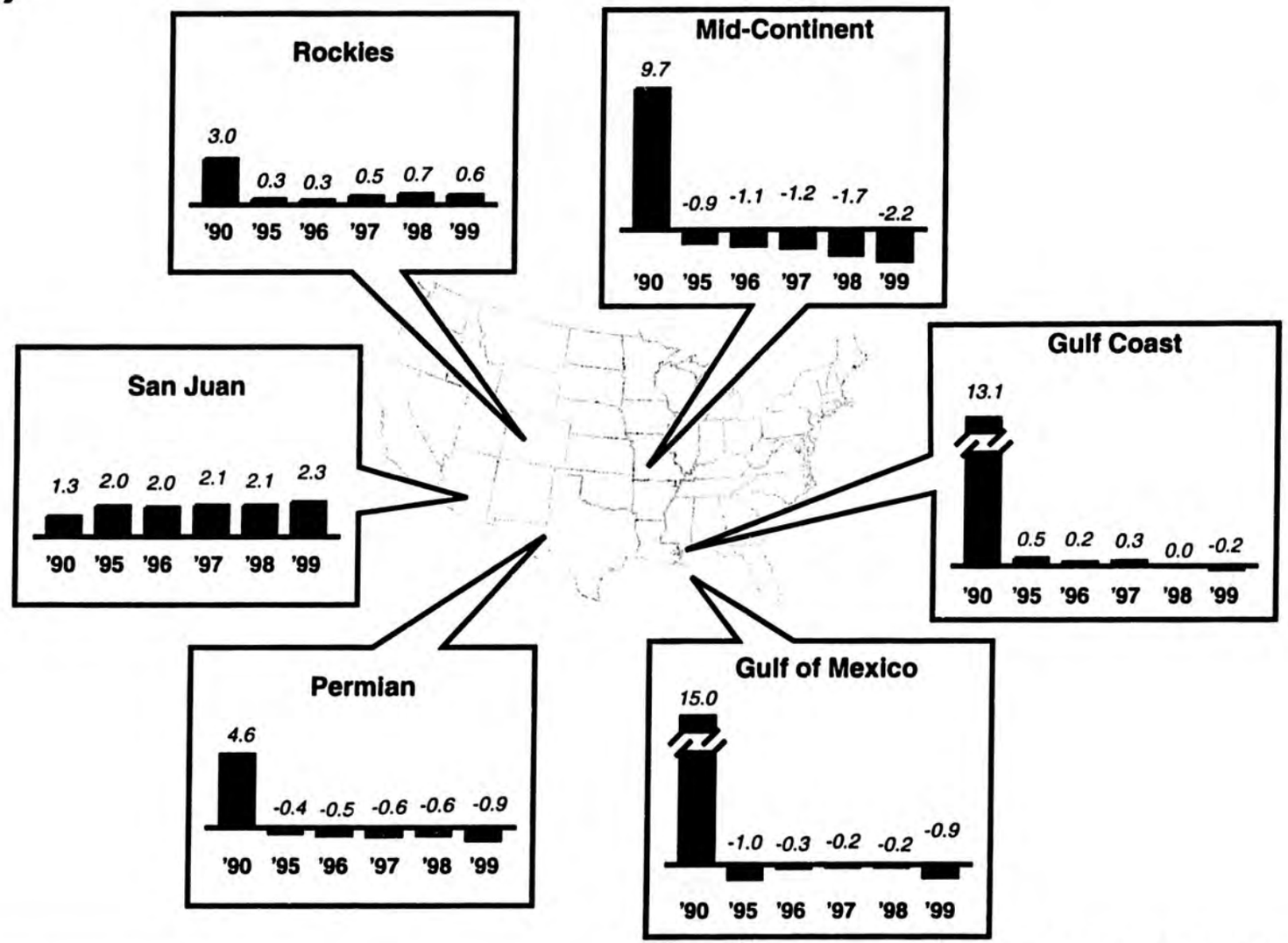
Source: Cambridge Energy Research Associates, Baker Hughes.
10328-10

Changes in Dry Gas Production Relative to 1990 Base Year (Bcf per Day)



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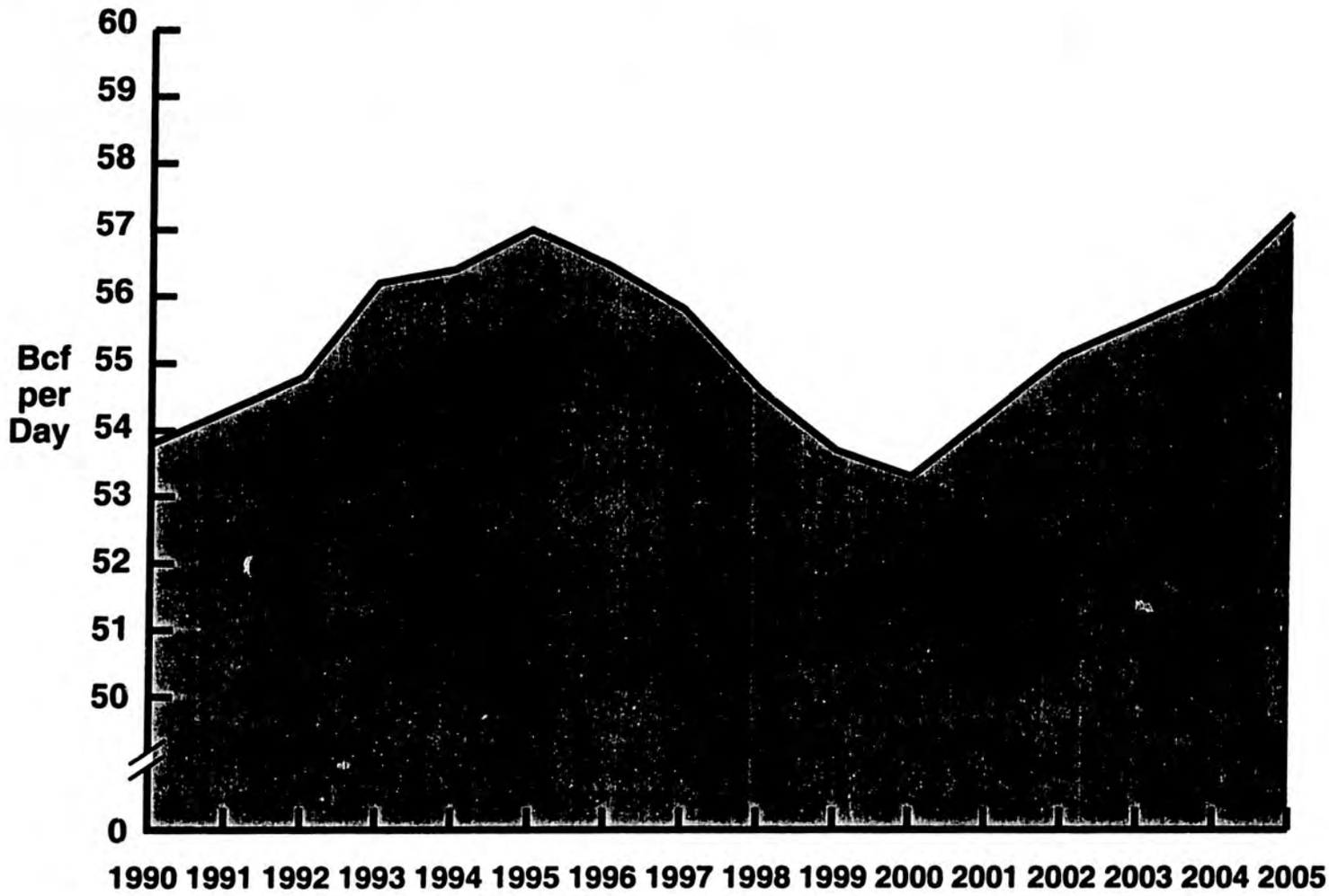
Source: Cambridge Energy Research Associates.

US Lower-48 Average Annual Wet Gas Productive Capacity



Source: Cambridge Energy Research Associates.
Updated June 2001

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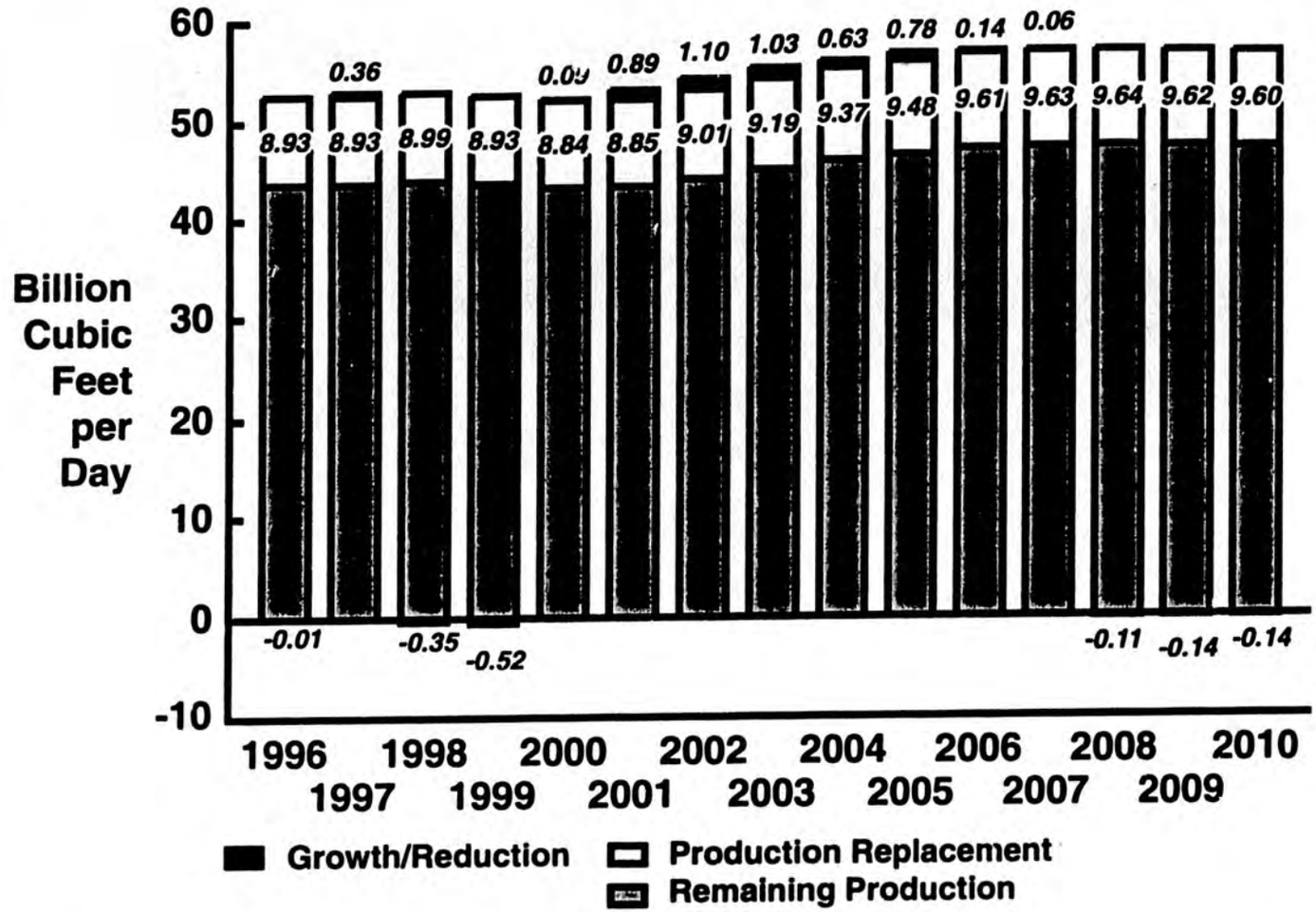
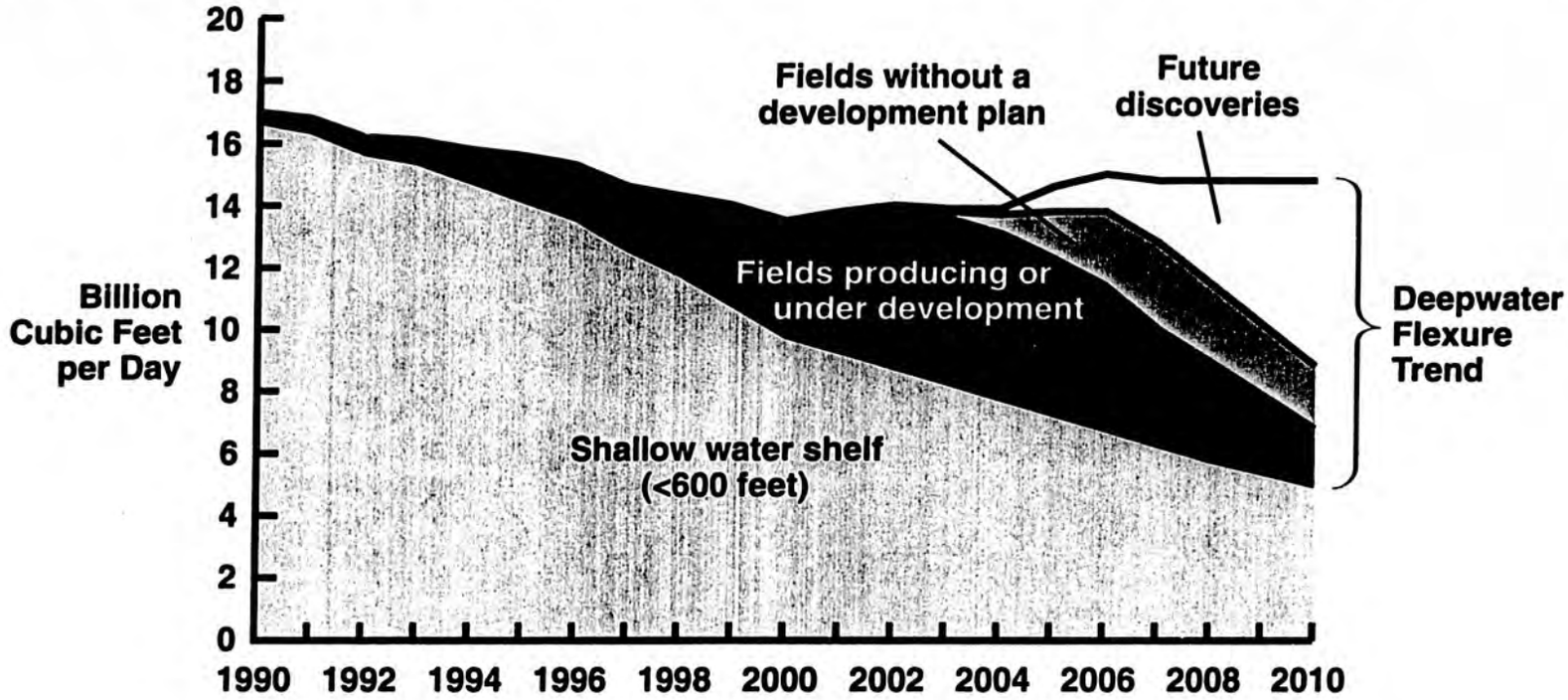
North American Onshore Gas Production*



Source: Cambridge Energy Research Associates.
*Gulf Coast, Permian & Mid-Continent, Rockies and San Juan, Western Canada
10328-6

US Gulf of Mexico*
Wet Gas Productive Capacity Outlook



Gulf of Mexico Gas Productive Capacity
(Bcf per day)

	1990	1995	1997	1999	2000	2001	2002	2003	2004	2005	2006	2007	2010
Shelf	16.7	14.2	12.6	10.8	9.8	9.3	8.8	8.3	7.8	7.3	6.8	6.3	5.0
Flexure Trend	0.3	1.4	2.0	3.2	3.7	4.5	5.2	5.6	6.1	7.3	8.2	8.5	9.8
Total Gulf	**17.0**	**15.6**	**14.6**	**14.0**	**13.5**	**13.8**	**14.0**	**13.9**	**13.9**	**14.6**	**15.0**	**14.8**	**14.8**

Source: Cambridge Energy Research Associates.
* Includes Louisiana and Texas only.
Updated June 2001

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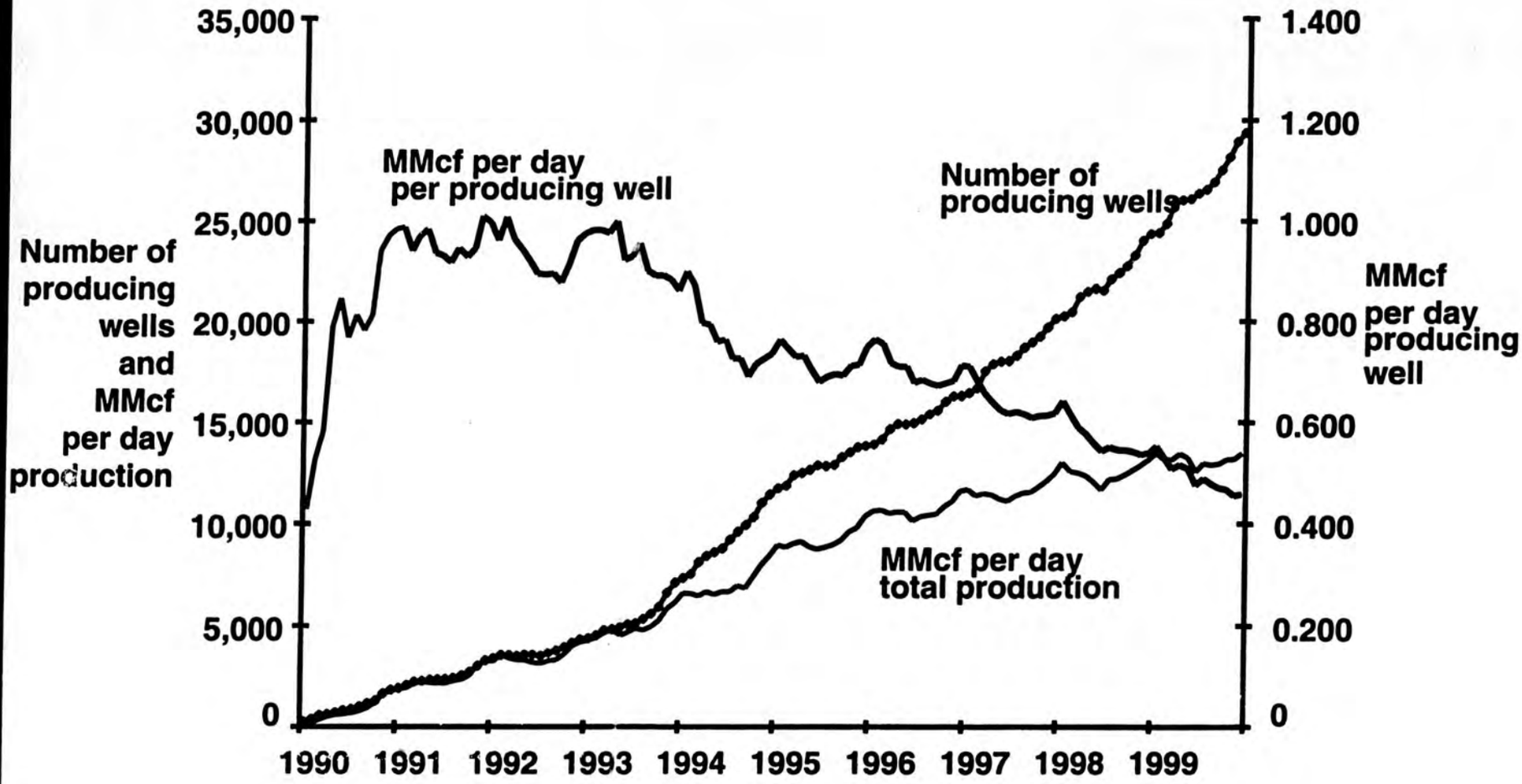
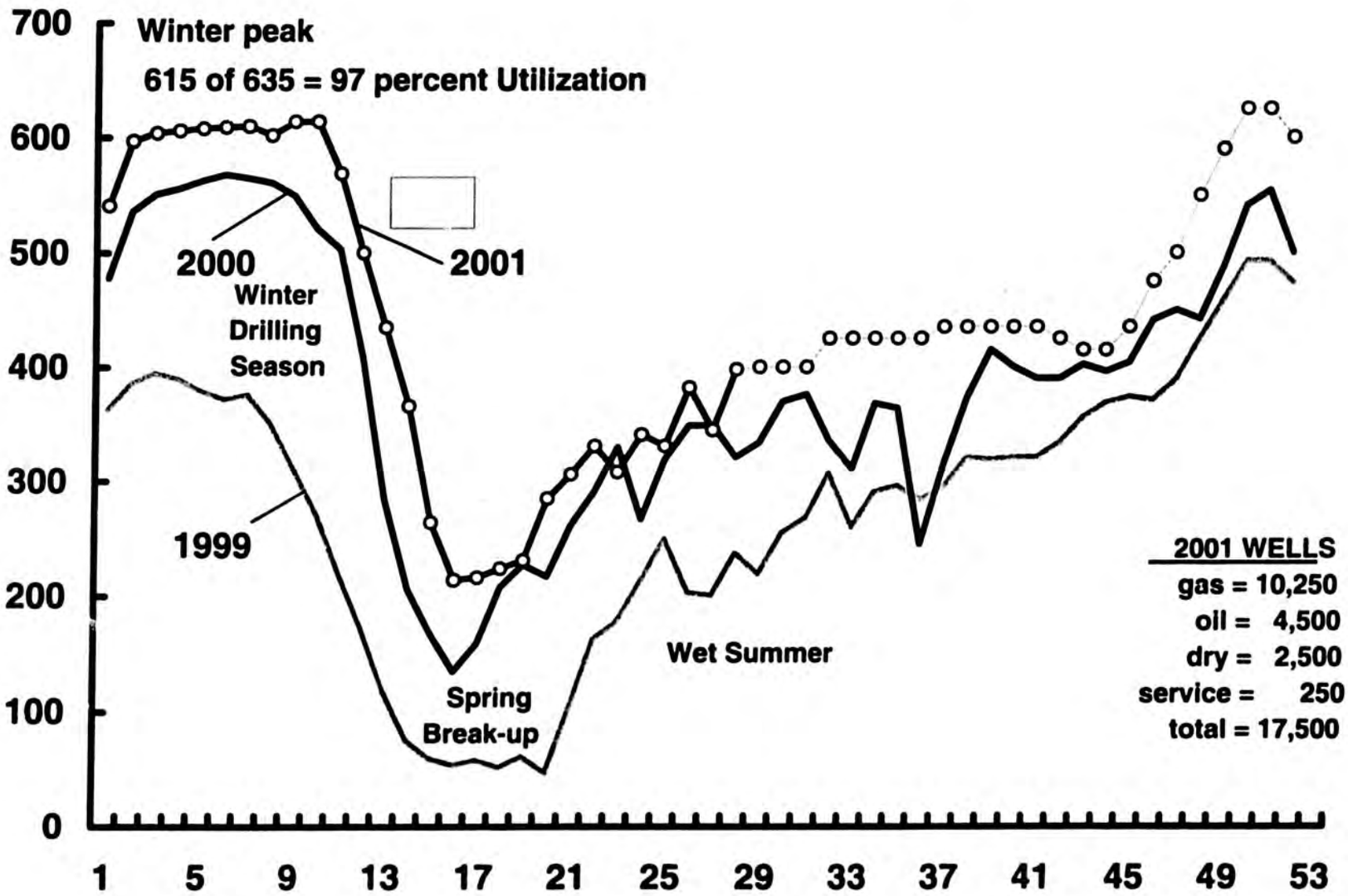
WCSB Wells and Average Production



Source: Cambridge Energy Research Associates.

WCSB Active Rig Count 1999–2001



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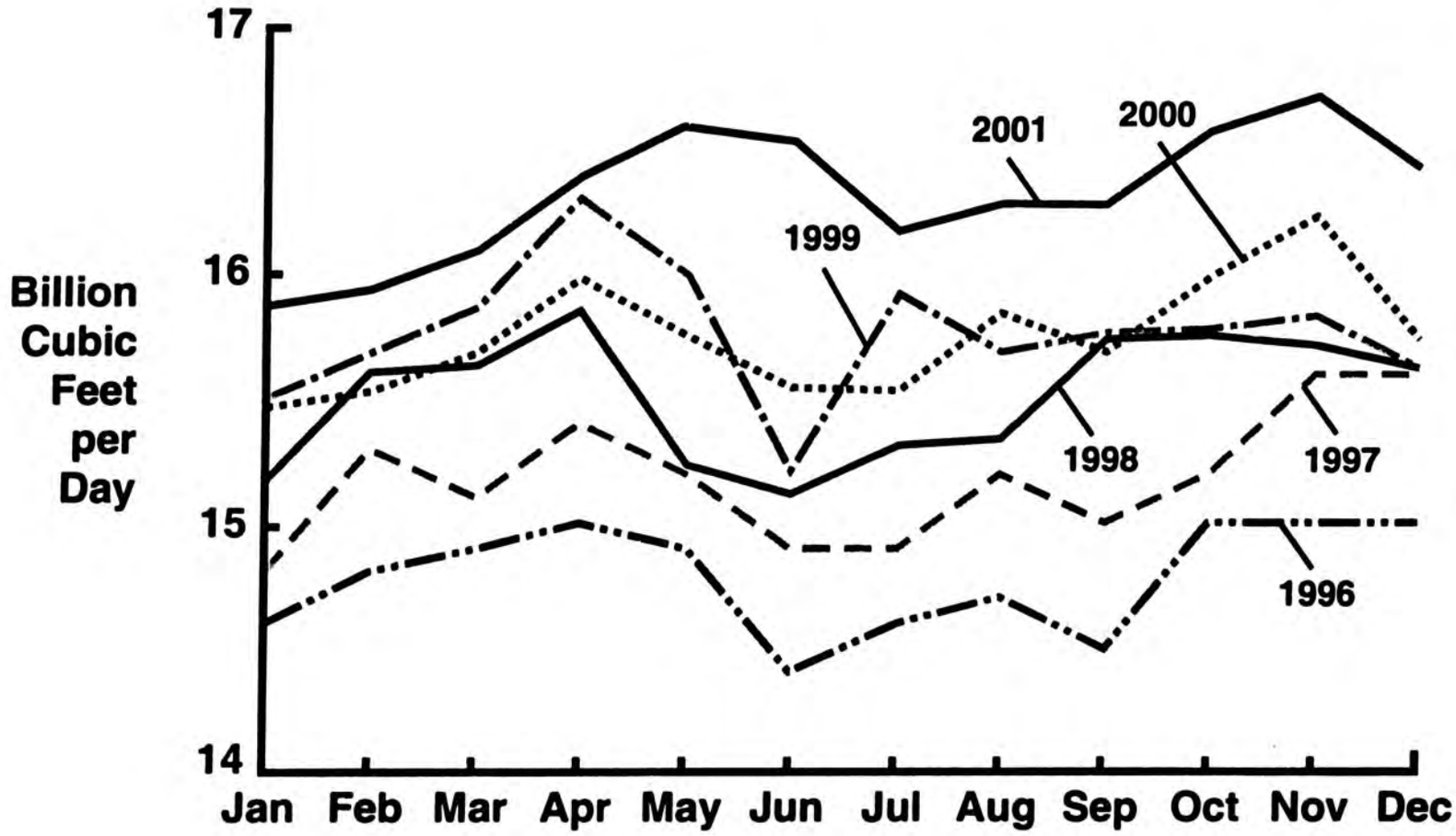
Source: Cambridge Energy Research Associates.
July 2001

Western Canadian Gas Supply



Source: Cambridge Energy Research Associates.

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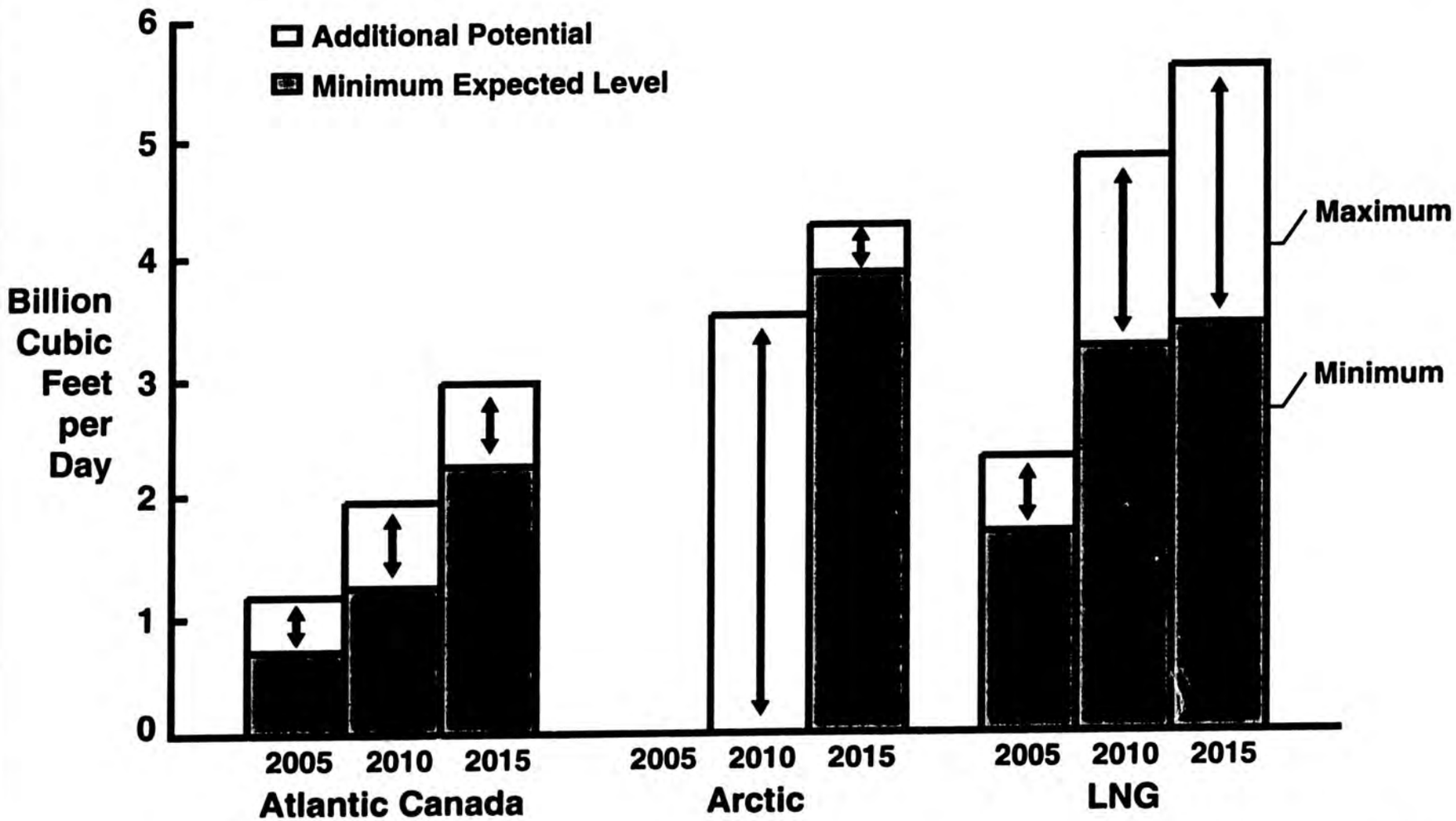
The Range of Production Levels from Frontier Areas



Source: Cambridge Energy Research Associates.

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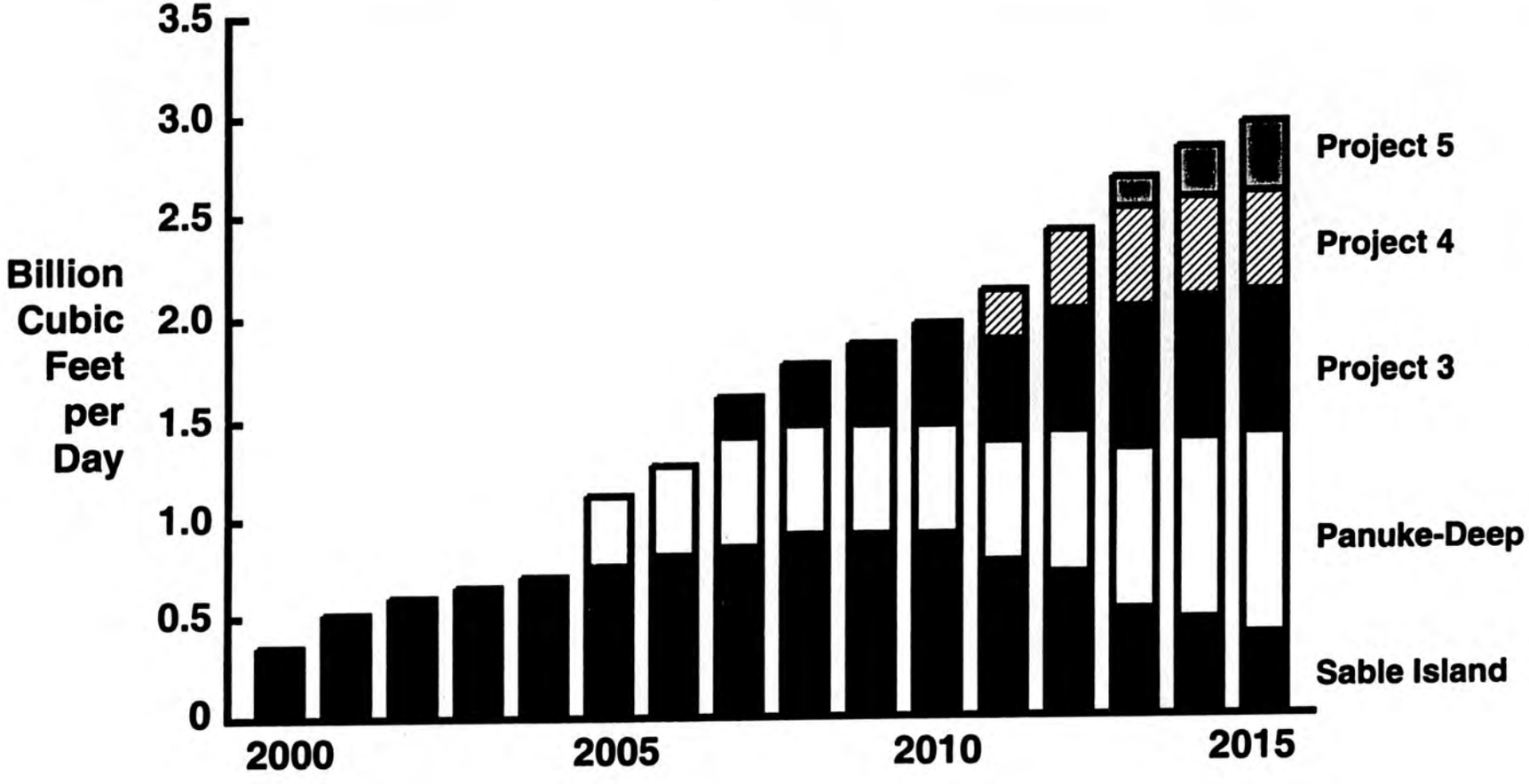
Scotian Shelf Supply Build



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Source: Cambridge Energy Research Associates.

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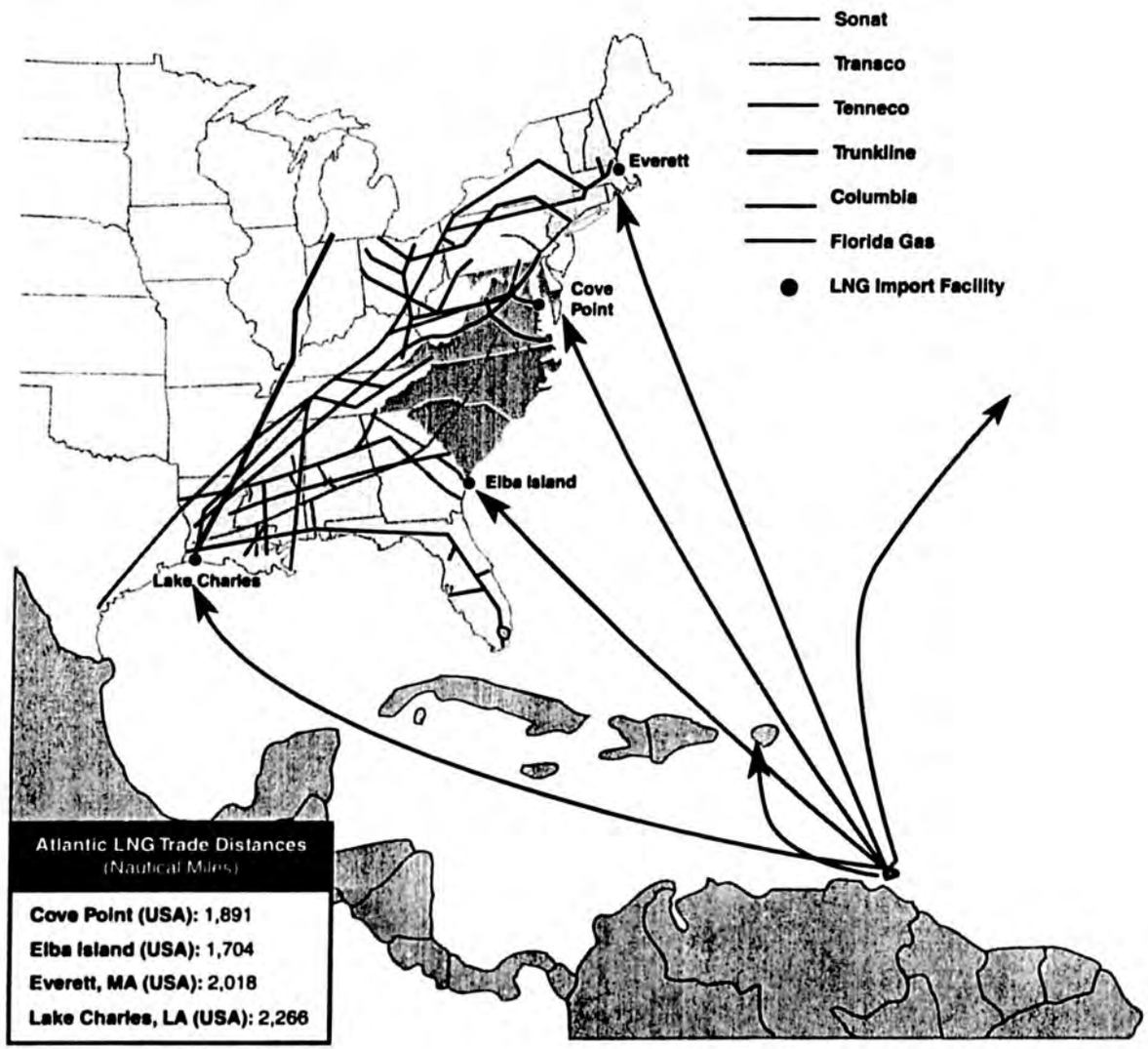
Potential US LNG Destinations for Atlantic LNG



Source: Cambridge Energy Research Associates.

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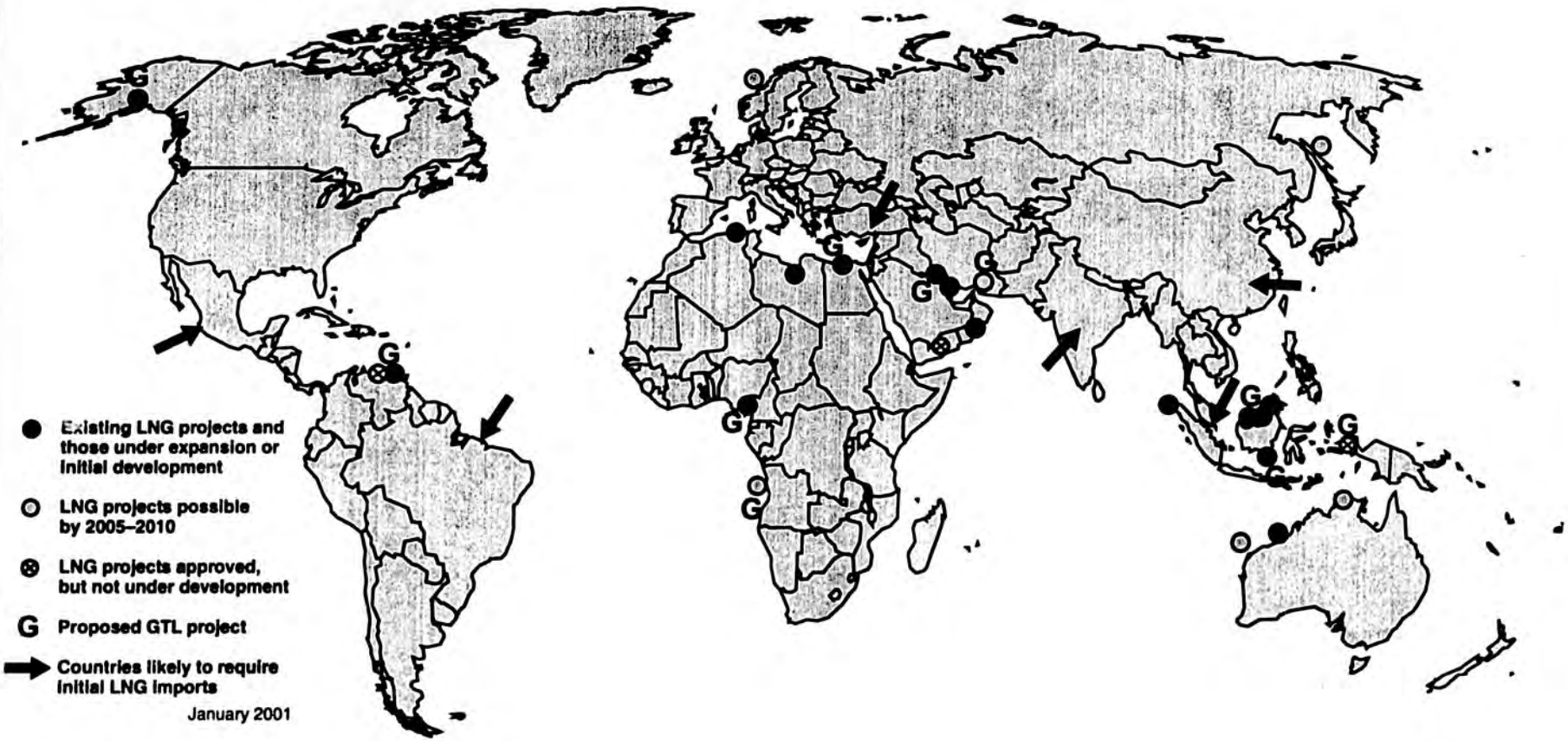
World LNG Facilities



Source: Cambridge Energy Research Associates.
Updated January 2001

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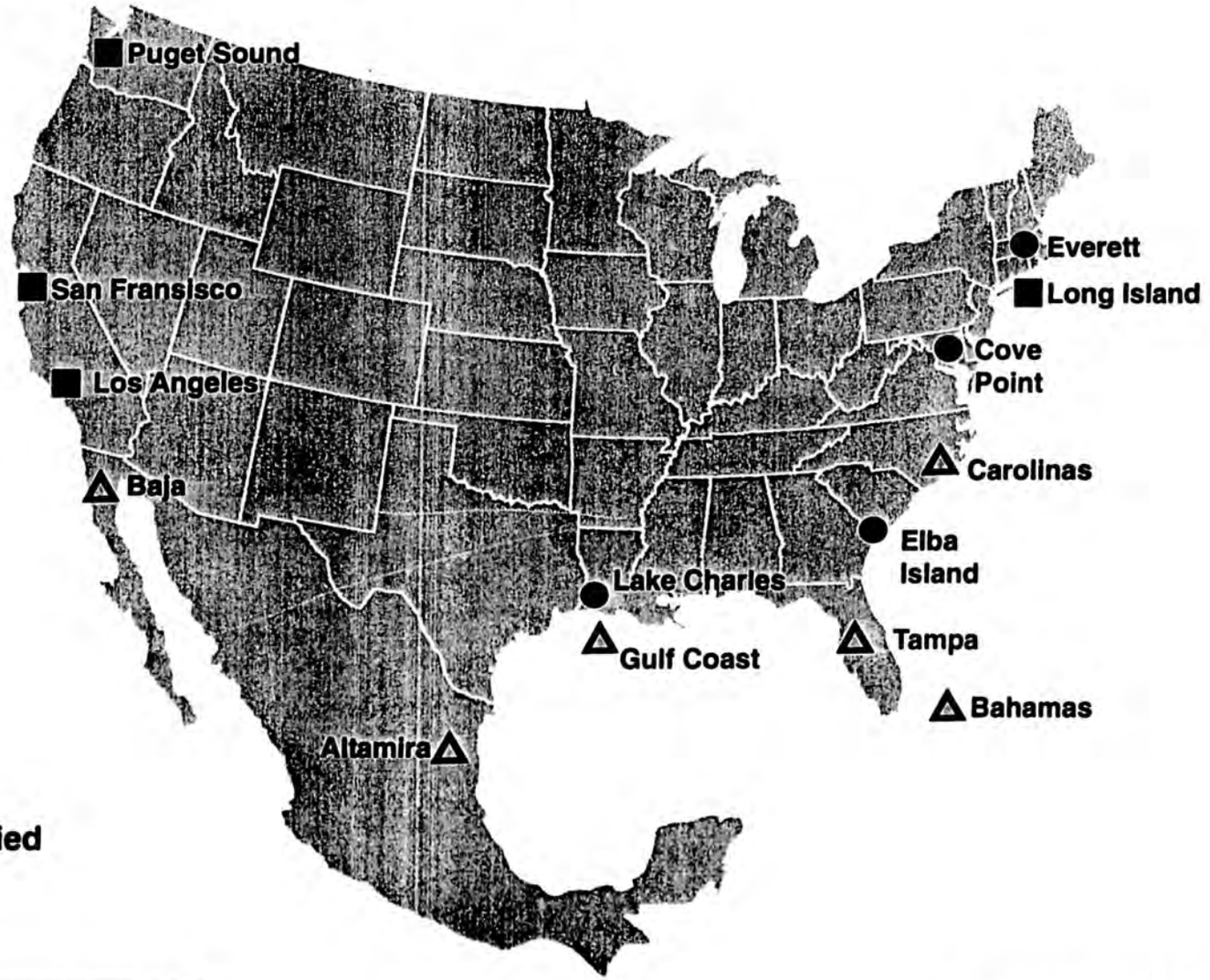
LNG Facilities in North America—Existing and Potential



Source: Cambridge Energy Research Associates.
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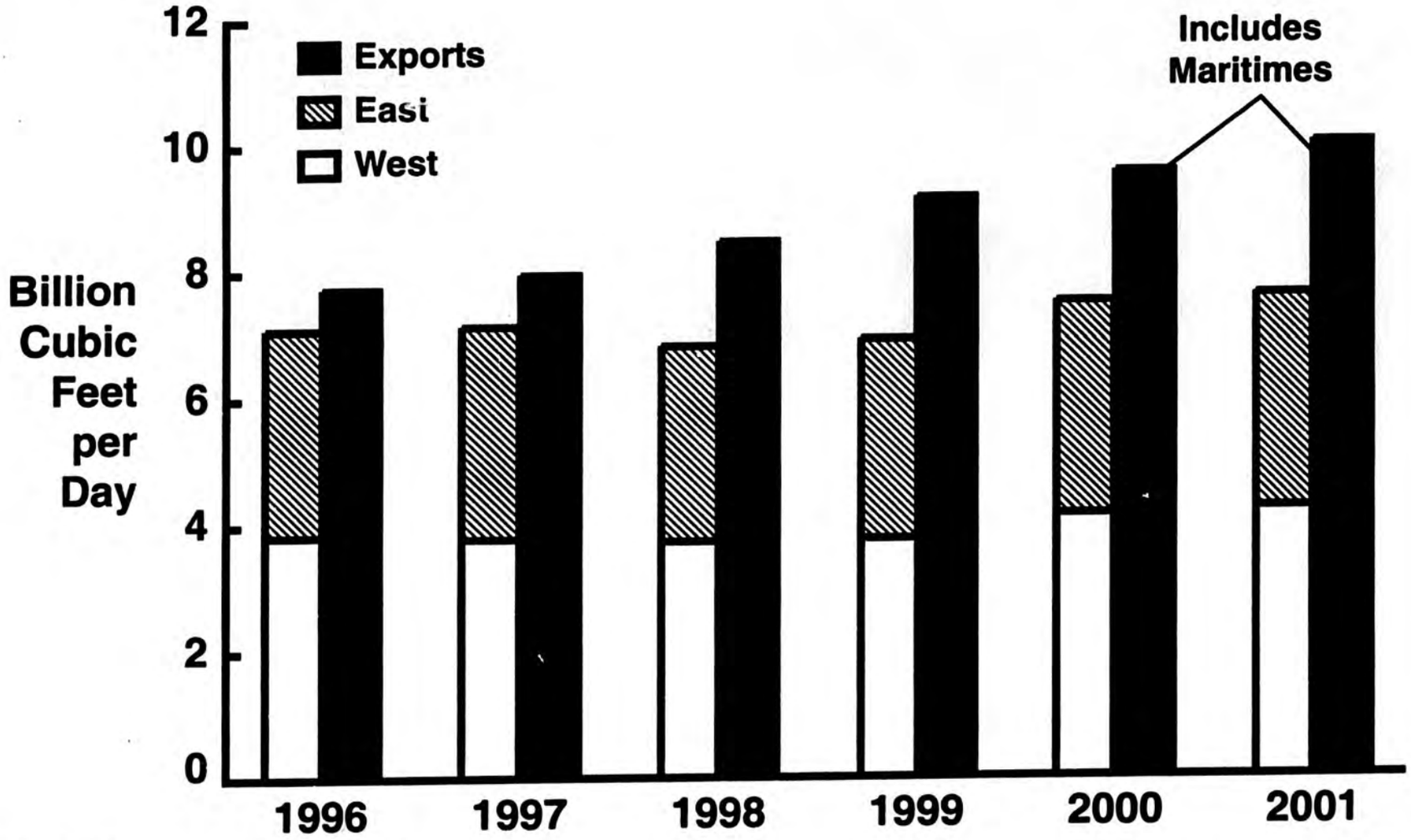
Canadian Domestic Demand and Exports



Source: Cambridge Energy Research Associates.

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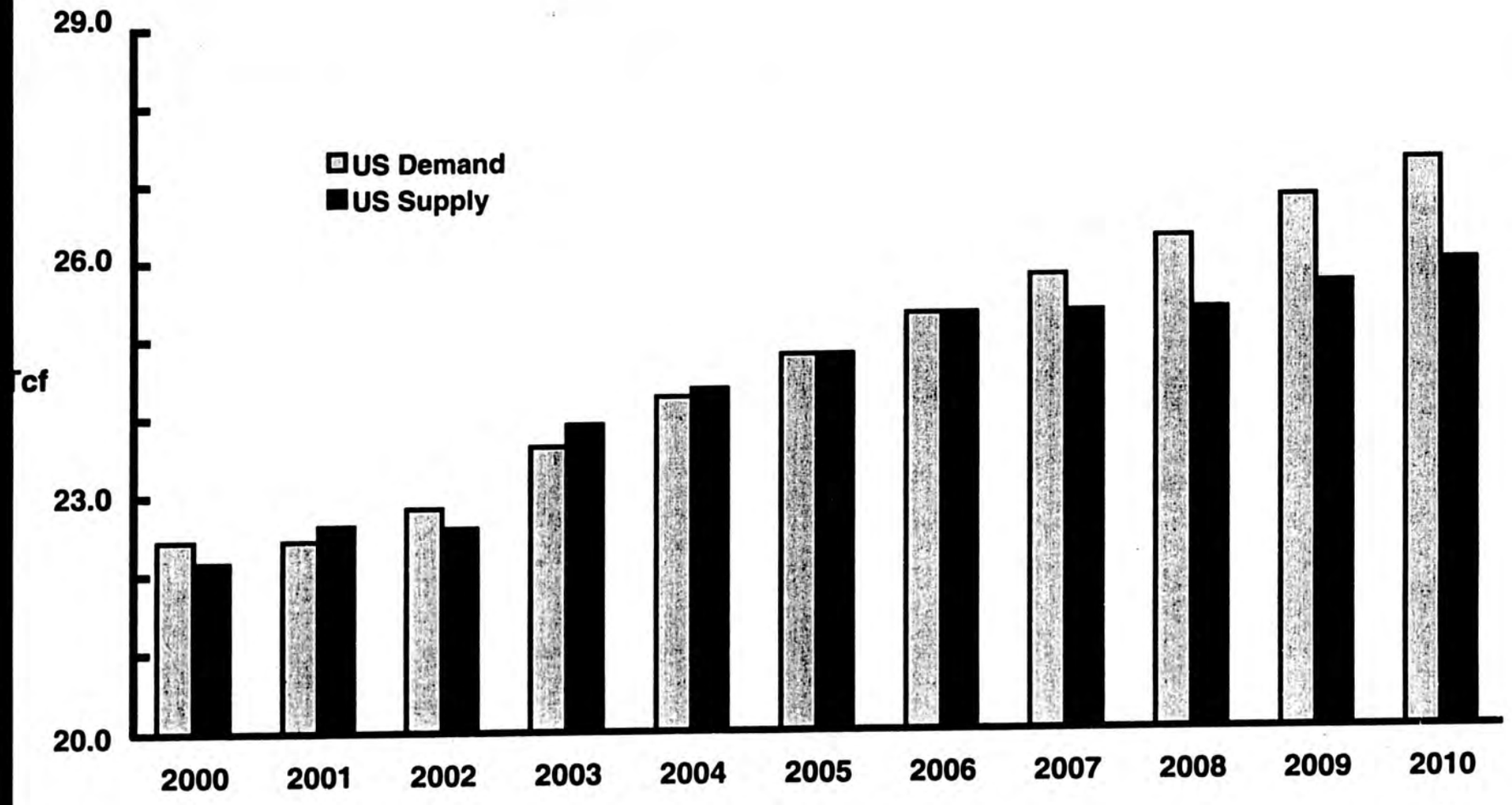
Lower-48 Supply/Demand balance without Frontier



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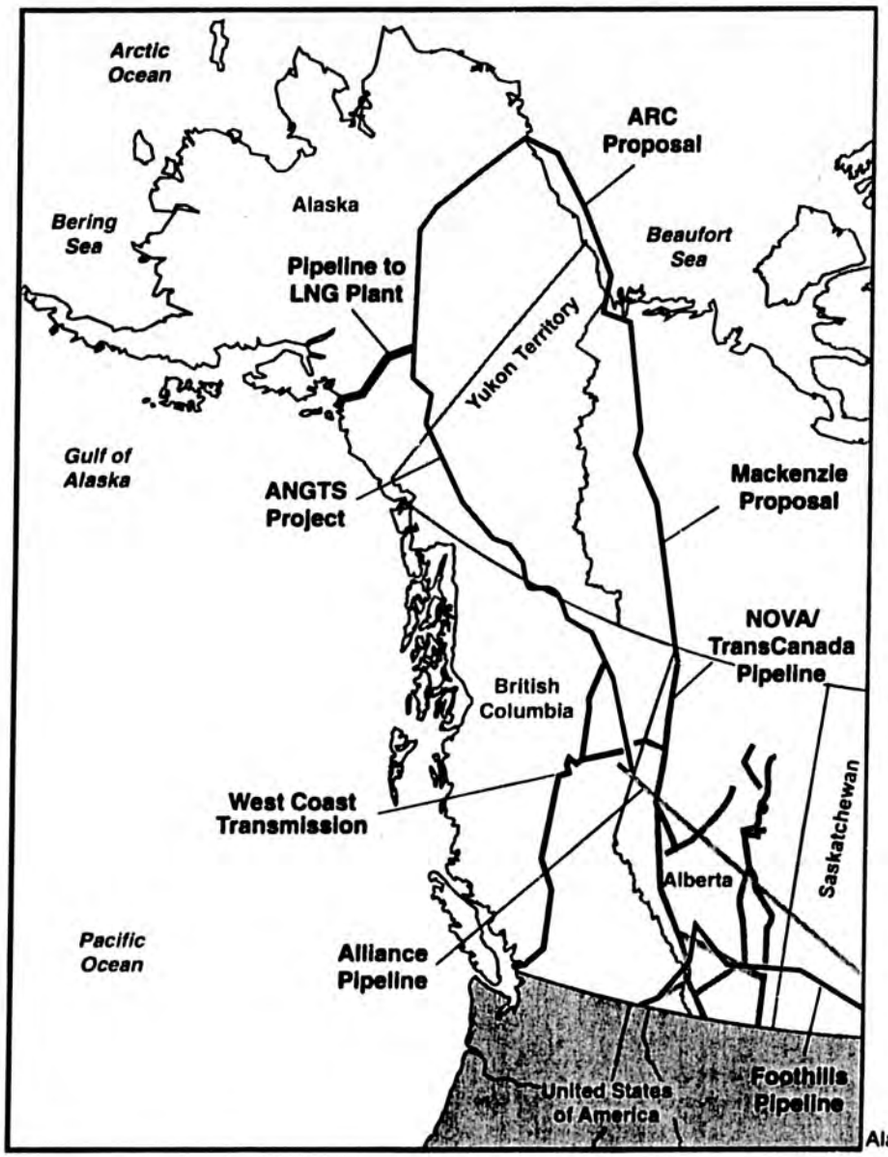
Arctic Gas Pipeline Alternatives



Source: Cambridge Energy Research Associates.

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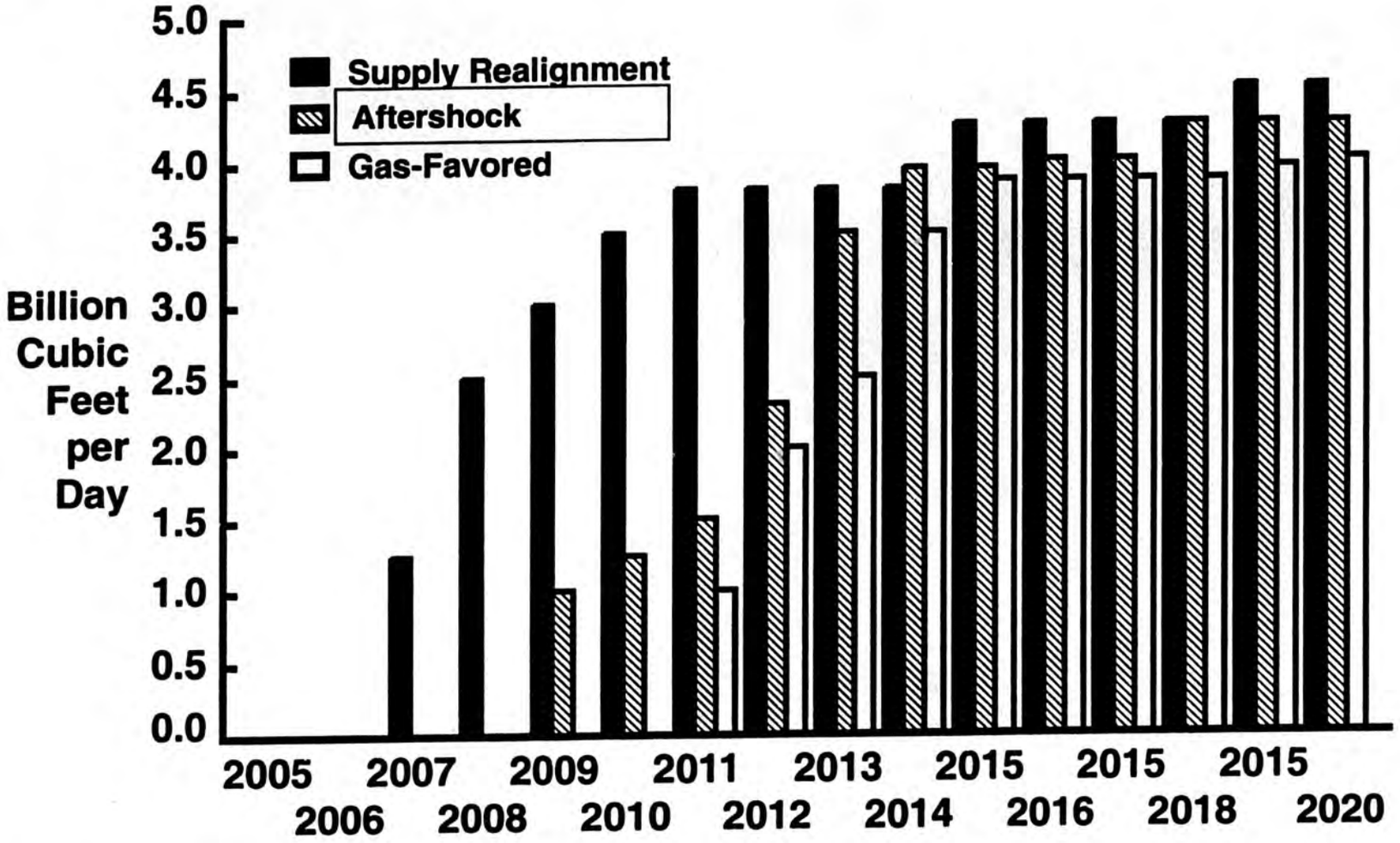
AlaskaStateLegislature_071501_nag

Arctic Gas Supply Build by Scenario



Source: Cambridge Energy Research Associates.

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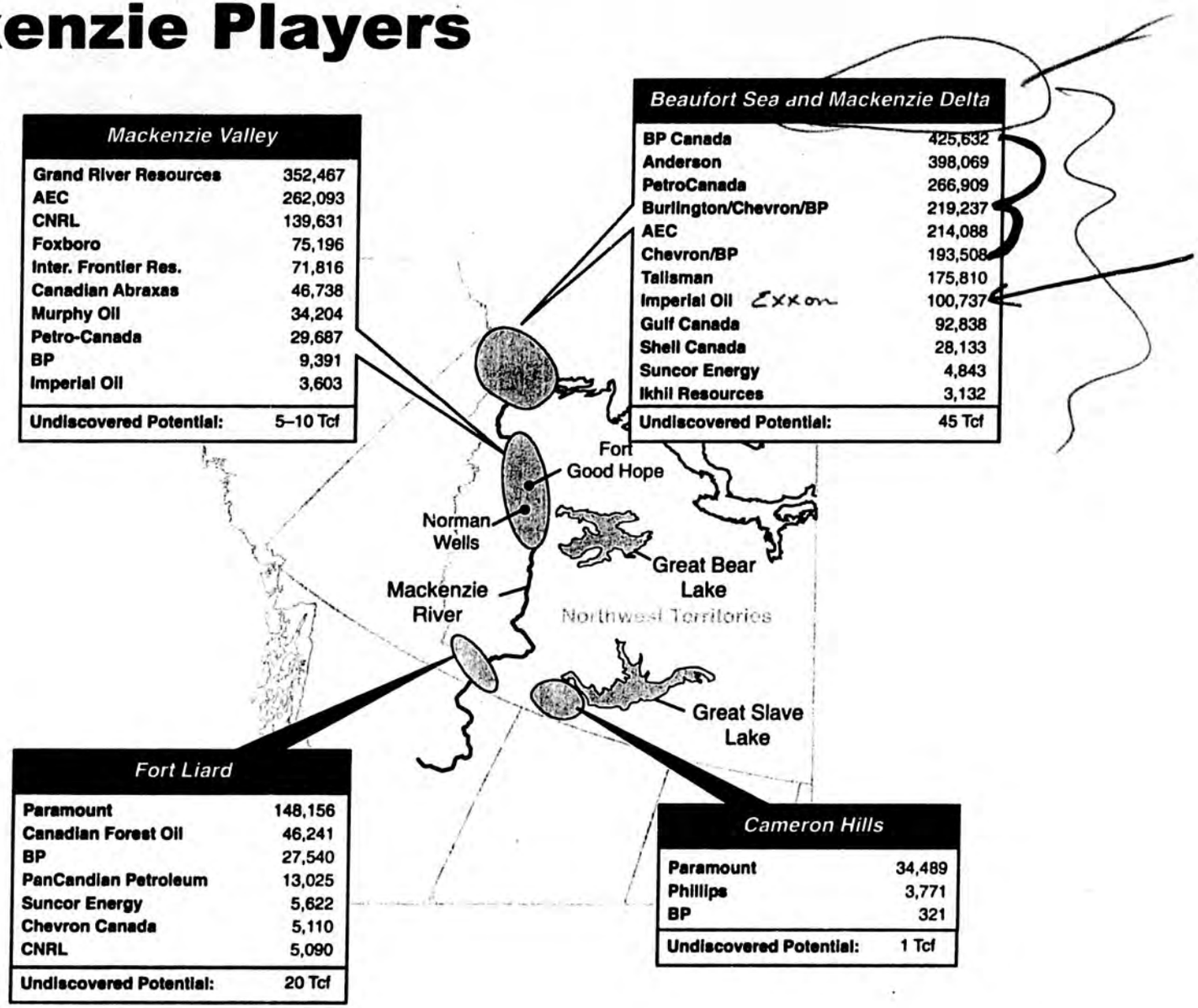
Mackenzie Players



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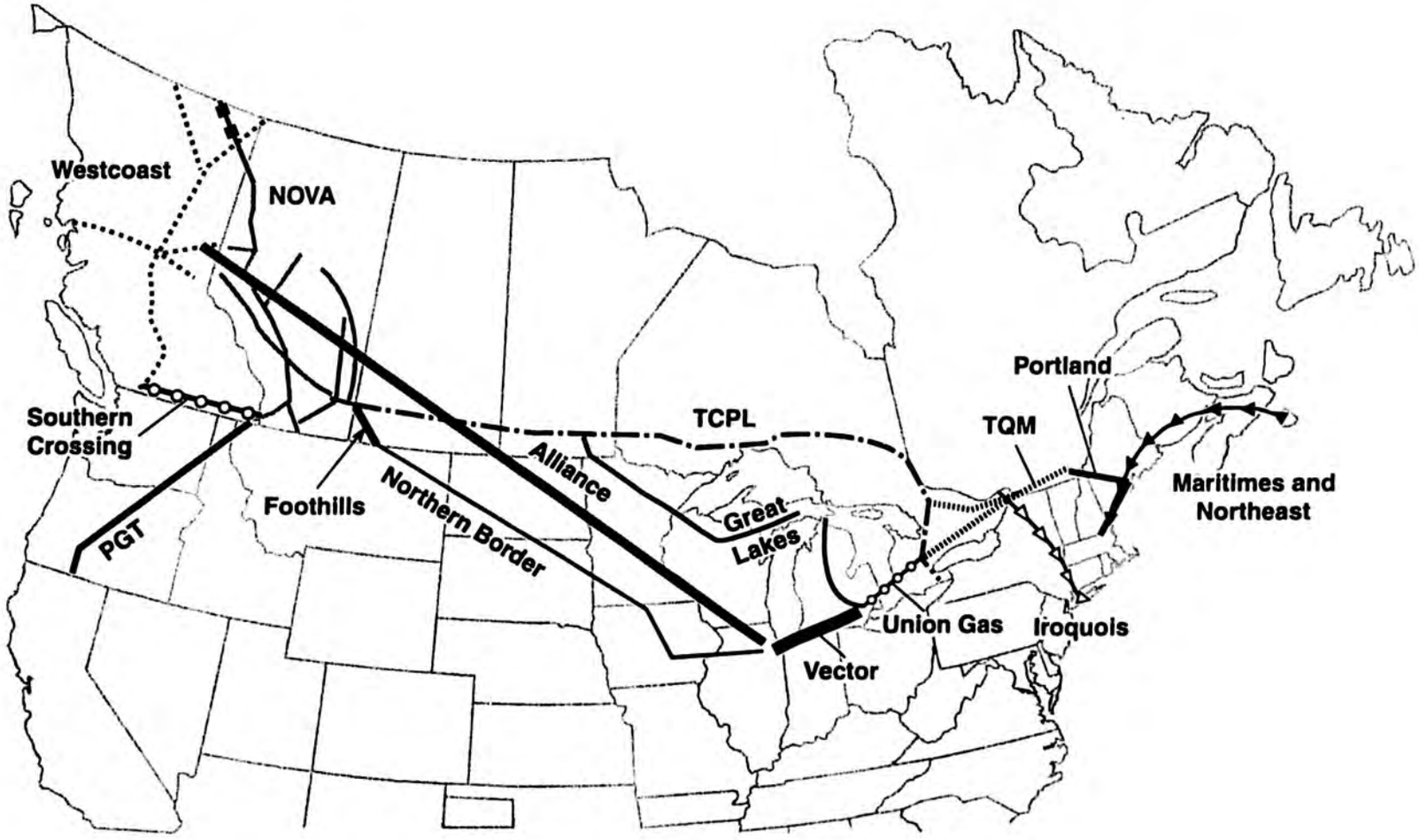
Source: Cambridge Energy Research Associates.

Canadian Natural Gas Pipeline Infrastructure



Source: Cambridge Energy Research Associates.

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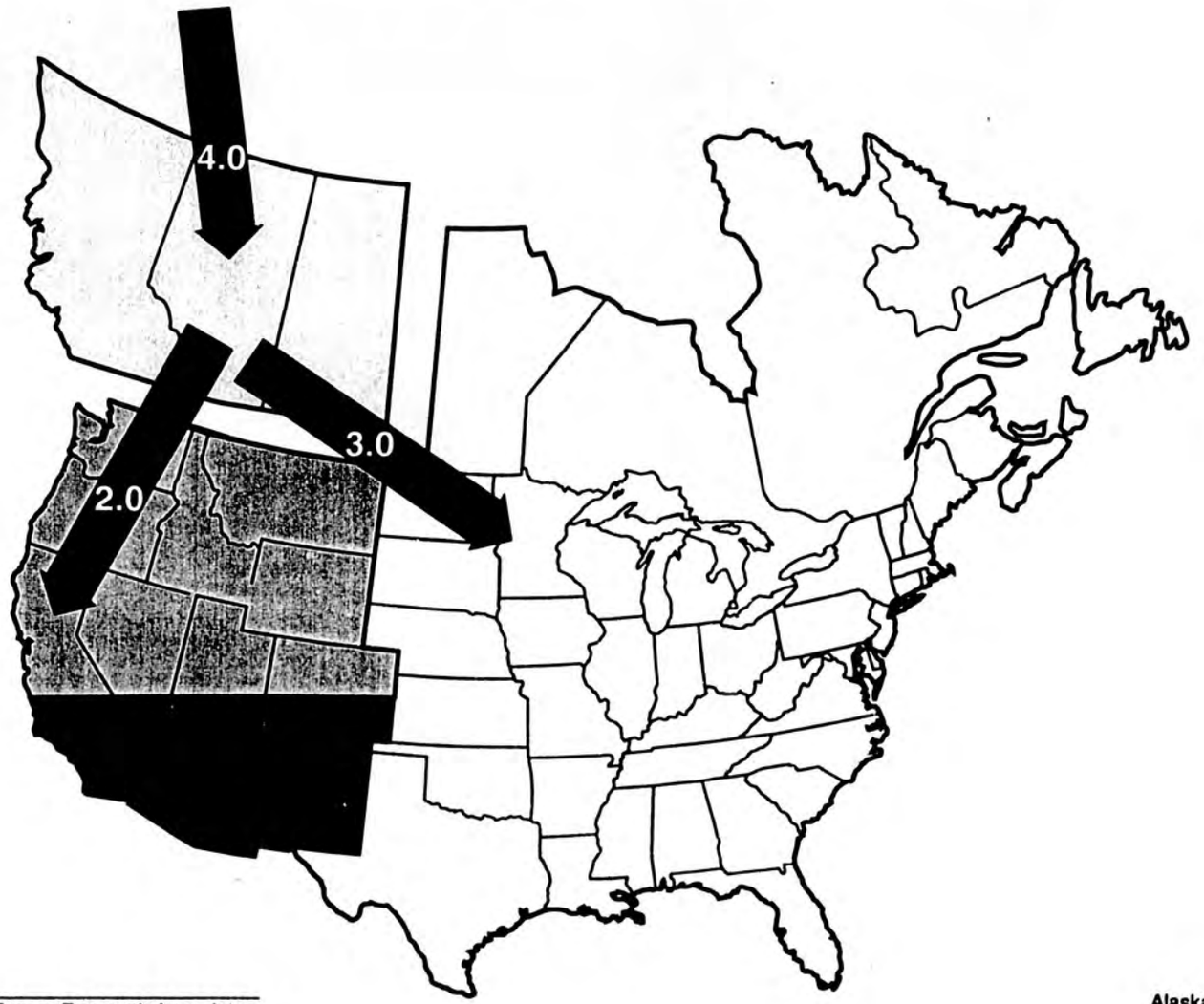
041900

Western Canada Pipeline Requirements—2010 (Bcf per day)



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Source: Cambridge Energy Research Associates.

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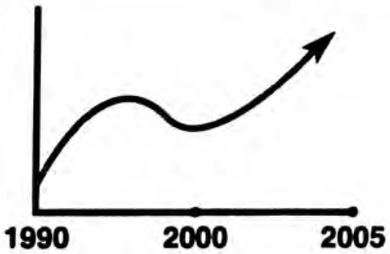
Northern Gas Pipeline Development Risks (1 of 2)



$3.00

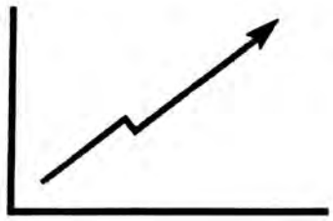
Gas Pricing

- Sustained Minimum $2.50 to $3.00 Needed



Supply Growth

- Resurgence from Other Regions Detrimental
- Coalbed Methane from Western Canada Negative Factor



Market Growth

- Continued Economic Growth Essential
- Fits with a 30 Tcf World
- Contraction from high Prices Detrimental



Political Intervention

- US and Canadian Government Positions on International Agreement
- Potential Delays Due Native Settlements Issue
- "In-fighting" Between Regional Governments
- Alaskan Pipeline Legislation



Downstream Capacity

- Excess Capacity Out of the West
- New Capacity all the way to Markets

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Source: Cambridge Energy Research Associates.

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Northern Gas Pipeline Development

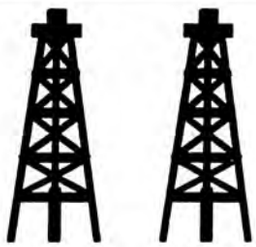
Risks (2 of 2)

Risk Sharing



Construction Delays

- Weather
- Equipment
- Workers



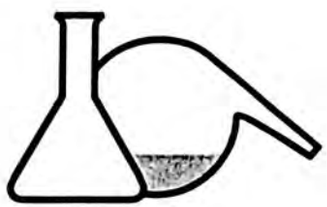
Resource Development

- Ultimate Capability
- New Sources



Risk Sharing

- Pipelines
- Producers
- Markets
- Financial Backing



Liquids

- Disposition
- Increase Economic Viability



Contracts

- Security
- Term Length
- Volume

CERA

Source: Cambridge Energy Research Associates.

00125-86

Natural Gas Liquids (NGLs)

What are NGL's?
- Components
- Extraction
- Transportation
- Usage
- Players

Alberta Experience
- Industry development
- Infrastructure
- Evolution

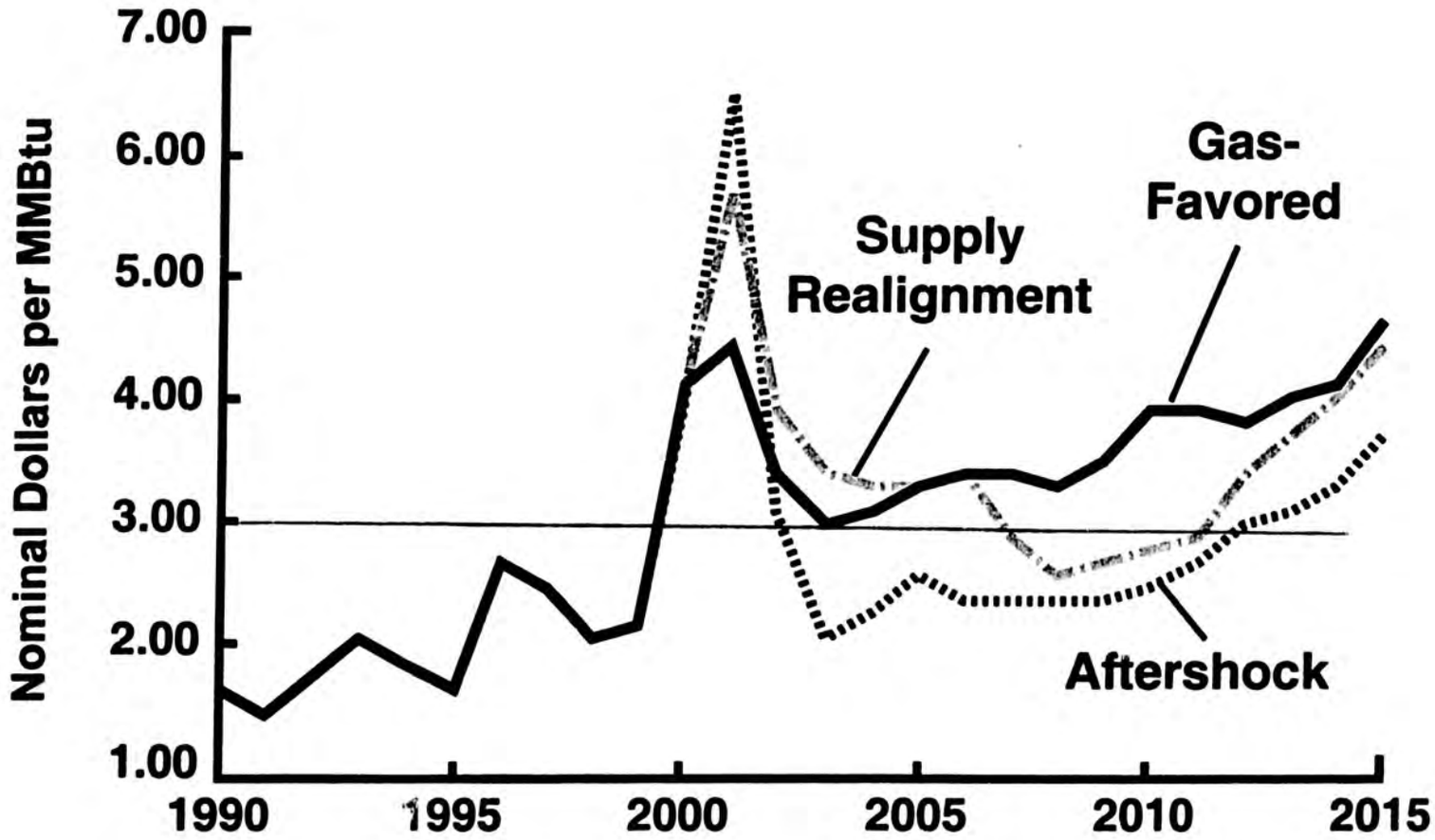
Impact of Arctic Liquids
- Alberta Position
- Industry Options

Alliance Impact
- Success for gas
- Disappointment for liquids

Alaska Opportunities?
- Advantages
- Disadvantages

CERA

CERA Spot Price—*Henry Hub*



CERA

Source: Cambridge Energy Research Associates.

10122-3

If you have any questions about this presentation or CERA in general, please feel free to contact

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CERA

Gas Pipeline Office
Anticipated Preapplication and Application Processing Tasks
Fiscal Year 2002

Process permits and other state authorizations necessary for proponents and their contractors to carry out preapplication work

Establish and maintain a multi-agency Gas Pipeline Office based on AO 187

Create and implement an integrated, streamlined state permitting process and plan to quickly and efficiently process applications

Work with proponents to review existing records and information and identify gaps that will need to be filled in carrying out the process and plan

Assist proponents in preparing and implementing plans to fill identified gaps

Provide preapplication and application processing consultation to proponents and their contractors

Provide proponents with pertinent information on land title and status, historical and archeological resources, environmental, health and safety, and other topics to assist their efforts and otherwise prepare to receive applications for a gas pipeline

Work with local governments to provide information and streamline permitting processes

Assist proponents to ensure timely and complete submission of an Alaska Coastal Management Program coastal project questionnaire, and provide the consistency review and determination in a timely manner

Work with the University of Alaska, the Alaska Mental Health Land Trust, and the Alaska Railroad Corporation to provide information and streamline permitting processes

Work with federal agencies to provide information and streamline permitting processes

Work with Canadian agencies to provide information and streamline permitting processes

Work with Native corporations, tribal councils and other aboriginal or First Nations organizations to provide information and streamline permitting processes

Work with the legislature and other State departments on legislative and regulatory initiatives related to gas pipeline permitting

Keep the public and interested and affected parties informed of State and other actions related to gas pipeline permitting

Perform legal work in support of preapplication and application processing efforts

Process right-of-way applications and related state permit applications

Alaska State Legislature
Joint Committee on Natural Gas Pipelines
July 17, 2001

Good afternoon and thank you for the opportunity to brief you on the status of gas pipeline right-of-way applications. For the record, I am Bill Britt, Gas Pipeline Coordinator for the Department of Natural Resources. I have provided the members of the Committee with information packets that contain copies of several of the documents that I will refer to today.

Summary of Natural Gas Pipeline Options

Let me start with a brief overview of the options currently being discussed.

There are, potentially, three ways to move natural gas out of Alaska:

1. pressurized natural gas,
2. liquefied natural gas, and/or
3. "white crude" from a gas to liquids process.

There are presently four pipeline routes being discussed:

1. Prudhoe Bay to Prince William Sound,
2. Prudhoe Bay to Nikiski,
3. Prudhoe Bay to the existing pipeline infrastructure in Canada via the Trans Alaska Highway, and
4. Prudhoe Bay to the existing pipeline infrastructure via an offshore route to the McKenzie River delta then south.

There are a number of companies, local governments and groups proposing options to move natural gas out of Alaska:

1. The Trans Alaska Gas System (TAGS) project is sponsored by the Yukon Pacific Corporation (YPC), a subsidiary of the CSX Corporation. It involves a LNG-grade gas pipeline substantially parallel to TAPS from Prudhoe Bay to Prince William Sound, with a LNG plant at Anderson Bay near Valdez.

2. The Alaska Natural Gas Transportation System (ANGTS) project is sponsored by the Alaskan Northwest Natural Gas Transportation Company (ANNGTC). Foothills Pipe Lines of Canada is serving as their agent for many discussions and actions. The ANGTS project involves a pressurized gas pipeline paralleling TAPS from Prudhoe Bay through Fairbanks to Delta Junction. From Delta Junction, it would proceed east to Canada along the Alaskan Highway, and then south following the highway to the pre-built portion of the project, which ties into the pipeline systems in Canada and the Lower 48.

3. The Alaska Gas Producers Pipeline Team (AGPPT) is a consortium of North Slope natural gas producers (BP, Phillips, and ExxonMobil) that is evaluating two routes – a highway route very similar to the ANGTS project, and a route offshore from Prudhoe Bay to the McKenzie River delta, then south to existing pipelines (the "over-the-top" route)..

4. The Alaska North Slope LNG Project is sponsored by the Sponsor Group, a consortium led by Phillips that includes Foothills and BP. The Sponsor Group is examining the feasibility of a gas pipeline from Prudhoe Bay to either Valdez or Nikiski, with a LNG terminal at one of those locations.

5. The Alaska Gasline Port Authority, composed of the North Slope and Fairbanks North Star Boroughs and the City of Valdez, is promoting a project similar to TAGS.

6. The Cook Inlet Pipeline Terminus Group is lead by the Kenai Peninsula Borough and is advocating a LNG project with the LNG terminal at Nikiski.

7. The Municipal Energy Resource Group (MERG), a Houston-based entity, also is advocating a pressurized gas pipeline along an offshore "over-the-top" route.

8. BP is presently constructing a prototype gas to liquids (GTL) plant at Nikiski. ExxonMobil has also advocated the GTL concept.

It should be noted that neither the routes nor "modes" are mutually exclusive. Multiple projects are possible.

Summary of Existing Permits for Natural Gas Pipeline Projects

Three of these proposed gas pipeline projects hold rights-of-way and other permits from the federal government or the State of Alaska:

1. The U.S. Department of the Interior Bureau of Land Management (BLM) completed an environmental impact statement (EIS) for TAGS and granted YPC a right-of-way in 1988. There are 17 years remaining on the federal ROW grant. A Presidential finding and an export license also are in place for TAGS. A separate EIS, conducted by the Federal Energy Regulatory Commission (FERC), covered the Anderson Bay terminal. YPC holds a conditional State right-of-way for the TAGS project. The conditional ROW lease* for TAGS was renewed in 1999 for 10 years. The requirements for YPC to proceed to a final lease are described in Section 2 of the conditional lease .

2. An EIS on ANGTS was completed and BLM granted a right-of-way in Alaska in 1980. There is a 1978 treaty in place between the United States and Canada sanctioning the proposal and the project has the associated Canadian permits and

approvals. ANNGTC began but did not complete the process for securing a State right-of-way.

3. The BP GTL plant on the Kenai has received all necessary authorizations and is under construction.

Overview of the State Right-of-Way Process

The process to secure a gas pipeline right-of-way on State lands is described in the Right-of-Way Leasing Act, AS 38.35. The steps, in brief, are:

- Receipt and public notice of an application
- Analysis of the application
- Negotiation of a draft lease
- Preparation of the Commissioner's Analysis and Proposed Decision
- Public notice of the availability of the analysis and proposed decision, and the public comment period
- Public comment period and public hearings on the analysis and proposed decision
- Consideration of comments from the comment period and hearings
- Preparation of a Final Decision
- Execution of the right-of-way lease, if that is the decision

The right-of-way lease is one of many authorizations required for any gas pipeline project. In late April, the producers' consultants URS and NRG submitted a draft report titled "Data Review and Permitting Requirements" To their clients I did not make copies for you, because the report contains over 150 pages. The list of permits, approvals, and consultations required for the Alaska portion of one or both of the routes being evaluated contains 29 categories of federal authorizations, 22 categories of state authorizations, and 8 categories of local and private authorizations. There would be anywhere from one (right-of-lease) to many (land use or water use) permits required in each category. According to the report, the lists considered only the pipeline and gas treatment plant, and did not consider associated or support facilities such as compressor stations, construction camps, access roads, material sites, disposal sites, staging areas, and other temporary use areas.

An applicant's ability to provide the necessary information in a timely manner is generally the most consequential factor in determining the time required to secure a pipeline right-of-way lease. Additionally, federal approval of a pipeline can be lengthy, mainly because of processes associated with the National Environmental Policy Act. Assuming reasonable applicant responsiveness and an expedient federal process, from 18-24 months would be required to permit a gas pipeline project.

Summary of Project Proponent Permitting Activities

The committee will be hearing from nearly all of the project proponents tomorrow, so I will be brief in my comments on the status of their recent and ongoing permitting work.

Yukon Pacific Corporation. On July 2, 2001, YPC submitted a refined pipeline centerline alignment for the TAGS project*. The submittal is being reviewed, and may result in amendments to the federal right-of-way grant and/or the state conditional right-of-way lease. I am unaware of other YPC activities related to permitting their project.

Alaskan Northwest Natural Gas Transportation Company. On March 6, 2001, the Alaskan Northwest Natural Gas Transportation Company sent a letter to me requesting that the State proceed with processing the ANGTS application*. On April 23, I requested that ANNGTC identify documents relevant to their application and submit them in a manner consistent with our application regulations*. The requested documents were delivered to my office on July 2, and are being reviewed. ANNGTC has already completed a large amount of work related to their right-of-way application, so the focus of our efforts in the near future will be reviewing existing data records to identify gaps in information necessary to process permits, and preparing a work plan to fill those gaps.

Alaska Gas Producers Pipeline Team. As you know, the producers' consortium has assembled a staff of approximately 90 personnel, and in April they awarded approximately $75 million in contracts for feasibility work associated with the highway and the over-the-top routes. The contracts comprised pipeline engineering, gas treatment facility engineering, natural gas liquids extraction facility engineering, environmental and regulatory work, and land status work. The number of consulting firms involved is large – for example, the two prime contractors for U.S. environmental and regulatory issues have 11 subcontractors in specialized areas. According to the producers, approximately 500 full time equivalents are engaged in the contractor efforts.

On July 6, the producers provided me with a list of the field studies they expect to undertake this summer. There are 21 studies on the list within Alaska. Several already have been completed, such as aerial surveys of nesting eiders. Some are in progress, such as ground surveys of cultural resources along the proposed highway route. Many have not begun, such as waterbody and fish stream surveys. We have begun processing the permits required for the studies (such as a collection permit from the Department of Fish and Game for the stream surveys) and communicating our expectations of the studies to the contractors.

The Sponsor Group. The Sponsor Group is continuing to assess the feasibility of a Kenai LNG project. They are assessing markets for the LNG, exploring possible synergies with the highway project, and working to reduce contingencies and thus increase the commercial viability of the project. Their consultants recently completed an environmental and regulatory evaluation of their project, with emphasis on the permittability of the Parks Highway route. Depending on the conclusions of the study, I expect to begin contact with the Sponsor Group as they seek to refine their permitting strategy.

Others. My office has had very limited contact with the Port Authority, the Cook Inlet Terminus Group, or MERG. I am unaware of any of those groups pursuing permitting activities. Since the BP Gas to Liquids plant does not involve a pipeline right-of-way authorization, my office is not directly involved.

Summary of State Government Activities

My specific roles in advancing a natural gas pipeline are listed in Administrative Order 187*. In brief, I am directed to coordinate State permitting and authorization processes, and to lead communications and coordination with federal and Canadian agencies related to permitting and authorizing one or more natural gas pipelines.

The document in your package* entitled "Gas Pipeline Office – Anticipated Preapplication and Application Processing Tasks – Fiscal Year 2002" contains a list of the short-term tasks associated with these roles.

I believe these efforts will:

- Positively affect the time required to permit and authorize a project by the State and federal governments
- Make the permits and authorizations we issue better
- Make the permits and authorizations that others issue more responsive to Alaskan priorities
- Make Alaska's financial return from the project greater

Progress on these tasks has been limited, due to lack of funding and lack of staff. As of July 1, funding ceased to exist for the Gas Pipeline Office. The limited funding provided to the GPO in FY01 allowed the hiring or assignment of liaisons from DEC and DFG, a DFG field leader, and me. Existing staff in several State agencies are performing very limited gas pipeline work, if and when discretionary time and funding is available. A large amount of that work has been directed toward securing funding for fundamental preapplication tasks, such as processing permits and other authorizations necessary for proponents and their contractors to carry out preapplication work. Although I have negotiated reimbursement MOUs with Foothills and the producers for the FY02 tasks on the list in your package, I cannot execute those agreements until LB&A approves general funding for the office. LB&A will be considering our budget request this evening.

There is good news, however. The staff at the State Pipeline Coordinator's Office has made considerable progress in collecting and organizing the ANGTS files. The GPO staff is working with Foothills and the Producers to move their efforts forward. I have received expressions of interest in GPO positions from a number of excellent candidates. We have found inexpensive housing for the GPO through the end of the year and will move into temporary (but collocated) offices in early August.

In closing, a lot is happening, and the pace of proponents' efforts is increasing. YPC submitted their refined centerline on July 2. Foothills submitted their consolidation of application support materials the same day. GPO staff had the first substantive permitting meeting with the producers' consultants on June 28, and received permitting materials as a result of that meeting on July 6. The Sponsor Group has just received a draft environmental and permitting report from their consultants.

If general funding for the GPO is approved, I will sign the reimbursement agreements with Foothills and the producers. We will then begin detailed work planning, and hiring to support the work plan, to continue moving the gas pipeline projects forward. If general funding is not approved, we will continue to fall behind the proponents, both in staff necessary to process their authorization requests, and in knowledge necessary to promote State interests.

Fiscal year 2002 will be an eventful time for project proponents and for State staff that will work with the proponents. I'm excited to have a role in these efforts. I would be happy to answer any questions you might have.

* Items provided to the committee in packets

YUKON
PACIFIC
CORPORATION
TRANS-ALASKA GAS SYSTEM

RECEIVED
JOINT PIPELINE OFFICE
01 JUL -3 AM 1:39

July 2, 2001

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Acting State Pipeline Coordinator
Joint Pipeline Office
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Anchorage, AK 99501

Mr. Jerry Brossia
Authorizing Officer
Joint Pipeline Office
411 West 4th Ave., Suite 2
Anchorage, AK 99501

Re: Trans-Alaska Gas System Refined Pipeline Alignment

Gentlemen:

Yukon Pacific Corporation (YPC) hereby submits to the Joint Pipeline Office (JPO), for review and approval, a refined pipeline centerline alignment for the Trans-Alaska Gas System (TAGS) liquefied natural gas project. This refined alignment is being submitted pursuant to Section 2(A) of the state Conditional Right-of-Way Lease ADL 413342, and the provisions federal Right-of-Way Grants F-83941 and AA-53559.

This refined centerline alignment is being submitted in two formats. First, as a set of 30 USGS digital raster graphic (DRG)-based alignment sheets at a 1:63,360 scale (Attachment A), and second in electronic format as both AutoCad and text files on a floppy disk (Attachment B).

The refined alignment is designated Rev. (revision) 4, and contains all proposed alignment changes since YPC's prior filings with the JPO and its constituent agencies, including the alignment sheets dated June 15, 1988 (Rev. 0), November 1, 1988 (Rev. 1), and February 1, 1992 (Rev. 2). Attachment C is a History of TAGS Pipeline Alignment Revisions and Description of July 2001 Refined Alignment Filing Approach.

The Rev. 4 refined alignment does not constitute a "substantial change" as defined in AS 38.35.050(c) because:

- The net increase in the amount of state acreage does not exceed ten percent of that contained in the Conditional ROW Lease. The Rev. 4 refined alignment (799.12 mi.) is 1.44 mi. longer than the JPO Rev. 2 alignment (797.68 mi.). That represents an increase in length of only 0.18 percent. The percentage increase in acreage would be identical.
- There are no changes that would use less effective environmental or safety mitigation measures or less advanced technology. In fact, use of our advanced, large scale digital orthophoto and GIS data base provided the environmental and technical basis for most of the alignment refinements.
- There is no fundamental change in the general route. The origin and terminus have not changed from those in our federal Grant of ROW or state Conditional ROW Lease.

This submission contains some proprietary and confidential data. YPC requests that this information be considered confidential and proprietary under applicable state and federal statutes and regulations including, but not limited to, AS38.05.035(a)(9)(E). YPC has no objection to the JPO permitting public review of any of this information, provided that third-parties are prohibited from making photocopies, electronic copies, or any other reproductions of its contents.

Of particular concern is the confidentiality of the electronic files containing the Rev. 4 refined pipeline centerline alignment as submitted on floppy disk as Attachment B. This refined centerline alignment may be represented on title plats or other paper or non-electronic media, but the JPO should prohibit reproduction or dissemination of this Rev. 4 refined centerline alignment in any electronic form whatever outside the JPO without YPC's express, written approval. YPC is prepared to assist the JPO in resolving any issues that may arise regarding disclosure of information contained in this submission.

Although not required for the purposes of JPO's review and approval of the refined pipeline centerline alignment submitted under cover of this letter, in the near future YPC will submit to JPO the refined pipeline centerline alignment on a 141-sheet set of 1 inch = 1,000 feet (1:12,000 scale) orthophoto-based alignment sheets pursuant to Section 2A of YPC's state Conditional Right-Of-Way Lease.

As requested by JPO during our prefiling meetings, YPC shortly will submit a compilation of the locations where the TAGS Rev. 4 refined pipeline centerline alignment crosses the Trans-Alaska Pipeline System (TAPS) and the Alaska Natural Gas Transportation System (ANGTS) ROWs, and where it is located within 200 feet of the centerline of the TAPS pipe or within 200 feet of the centerline of the ANGTS ROW.

Enclosed is a check in the amount of $100 as a state filing fee. It is our understanding there is no federal filing fee. If this is incorrect, please notify us and we will immediately submit the appropriate fee.

Thank you for your consideration and assistance in this matter.

Sincerely,

Jeff B. Lowenfels
President and CEO

Attachments:

A. TAGS Rev. 4 refined pipeline centerline alignment (Set of 30, 24" x 36" alignment sheets at 1:63,360 scale in separate stapled document)
B. TAGS Rev. 4 refined pipeline centerline alignment (AutoCad and ASCII text files on floppy disk)
C. History of TAGS Pipeline Alignment Revisions and Description of July 2001 Refined Alignment Filing Approach

ATTACHMENT A

TAGS Revision 4 Alignment Sheets

Stapled Set of 30, 24" x 36" Alignment Sheets at 1:63,360 Scale

Submitted to JPO as Separate Document

July 2, 2001

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2945 SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPLINE, 2001-02

ATTACHMENT B

TAGS Revision 4 Centerline Alignment

TAGS pipeline centerline PIs submitted in two formats on single floppy disk

- AutoCad Release 14 File titled "TAGS_Rev4_Centerline_R14_UTM27-6IF_(07-01-01).dwg"
- ASCII Text file titled "TAGS_Rev4_Centerline_UTM27-6IF_(07-01-01).txt"

(AutoCad file and all coordinates are in NAD 27 UTM Zone 6 International feet)

ATTACHMENT C

History of TAGS Pipeline Alignment Revisions and Description of July 2001 Refined Alignment Filing Approach

July 2, 2001

This document presents a history of the Trans-Alaska Gas System (TAGS) pipeline alignment revisions, and describes the approach Yukon Pacific Corporation (YPC) has taken in developing its present refined alignment filing.

Alignment Refinement History

The initial TAGS alignments submitted to the Bureau of Land Management (BLM) and the Alaska Department of Natural Resources (ADNR) in support of YPC's application for its federal and state ROWs, respectively, were made on USGS maps at a scale of 1:63,360.

The alignment submitted to BLM was "Rev. 0" (dated June 15, 1988). The alignment submitted to the ADNR was "Rev. 1" (dated November 1, 1988). The only Rev. 0 to Rev. 1 modification was a realignment of the pipeline between Rev. 1 mileposts 405.0 to 421.3, on state land. The pipeline was realigned from the east to the west side of TAPS Pump Station 7 and Grapefruit Rocks to avoid a peregrine falcon nest and public recreation around Grapefruit Rocks.

These alignment submittals were digitized by BLM and ADNR and entered on their land status plats. For the purposes of this document, these BLM and ADNR alignments are jointly referred to as the "JPO alignment."

In 1993, at YPC's request, both its federal ROW Grant and state Conditional ROW Lease were amended from a " 36-in diameter" pipeline to a "large diameter" pipeline. This change reconfigured the number and locations of compressor stations, and required one minor realignment of the pipeline to accommodate a new compressor station. This change was made to the Rev. 1 pipeline alignment between miles 566.6 to 571.6 (on federal land at Darling Creek near the Delta River). This was the only change to Rev. 1 and was reflected in Rev.2 (dated February 1, 1992), which is the current JPO alignment.

From 1992 to the present, YPC has made technical and environmental improvements to refine the TAGS alignment using tools not available at the time of the Rev. 2 submittal. YPC flew controlled aerial photo missions and created an ortho-photographic based geographic information system (GIS). Ten-foot topography was produced in conjunction with the ortho-photography and surficial soils were mapped along the TAGS ROW and added to the GIS. Thus, improvements to the Rev. 2 alignment have been made over these years using YPC's GIS, expertise of arctic pipeliners, field reconnaissance, proprietary pipeline computer simulation models, numerous other tools, and the advice of agency personnel. The bulk of these improvements to Rev. 2 are reflected in Rev.3 (dated October 1, 1999). Rev. 3 was

developed as the basis for updating YPC's project cost estimate and project description in 2000 and was not released externally.

Minor changes to Rev. 3 constitute the Rev. 4 pipeline alignment, which is the subject of YPC's present refined alignment filing. Rev. 4 incorporates all changes that have been made to the Rev. 2 JPO alignment. The most recent Rev. 4 draft is dated July 1, 2001. The types of Rev. 4 modifications to the JPO alignment are discussed below, and are listed individually on a mile-by-mile basis in the attached table titled TAGS Rev. 2 to Rev. 4 Realignments.

Rev. 4 Refined Alignment

The TAGS Rev. 4 refined pipeline centerline alignment contains changes from the Rev. 2 JPO alignment that vary from many quite minor resolution issues to a few large realignments. To provide meaningful information that differentiates minor changes from those that should bear scrutiny, YPC has developed a descriptive system of five categories that encompasses all the differences between the TAGS Rev. 2 alignment currently indicated on the JPO plats and the present Rev. 4 refined alignment.

Because the state conditional lease ROW is 1,000 feet wide, extending 500 feet on each side of the centerline, YPC has used that ROW width as a reasonable measure for differentiating alignment changes. This 1,000-ft. conditional ROW is the area within which mineral closure orders have been executed in reasonable anticipation that the centerline alignment would change.

Realignments Within the 1000-ft. ROW

This category includes three types of realignments. The first two are minor to the extent that they are not cataloged in the attached TAGS Rev. 2 to Rev. 4 realignments table. The third type consists of a few small changes that warrant cataloging.

Resolution variations – The TAGS alignment, as originally filed with JPO, was at 1:63,360 scale on a USGS topo base. Because of the scale involved, the width of the alignment line drawn on the media, distortions of the media itself, errors in geo-referencing the media, and errors in digitizing the alignment, the very process of transferring the original TAGS alignment to the JPO plats produced errors of resolution in the JPO alignment. Although there are many of these inaccuracies, in almost all cases they are very minor and obvious. Because they are minor, and because only one is outside the 1,000-ft. ROW, the TAGS Rev. 2 to Rev. 4 Realignments table does not catalog any resolution variations within the 1,000 ft. ROW.

Micro realignments – These are non-substantive realignments that are all within the 1,000-ft. ROW. They were made to address very local conditions that generally were not represented at the 1:63,360 USGS map-based scale used in YPC's original filing. YPC's 1:12,000 scale ortho-photographic based GIS, developed since the initial filing, provided significantly more detail for refining the pipeline alignment. Examples:

- On the North Slope, moving to avoid a tundra pond or wetland complex.
- In more rugged terrain, avoiding a side slope by aligning parallel to the fall line or along ridge crests.

In a similar manner to the resolution variations, because these micro alignments are minor and none is outside the 1,000-ft. ROW, the TAGS Rev. 2 to Rev. 4 Realignments table does not catalog any micro realignments.

Small realignments – These constitute a small group of realignments that are within the 1000-ft. ROW, but which were made for a specific technical or environmental purpose and are more than micro realignments. While relatively small in number and scale, YPC believes these changes should be flagged and cataloged. An example would be the realignment near Slope Mountain (Mile 119.45) where the Rev. 4 alignment has been moved from the east side to the west side of the Dalton Highway to consolidate all development for a linear distance of 6.32 miles, but stays within the 1000-ft. ROW. There are three small realignments between Prudhoe Bay and Anderson Bay.

Realignments Outside the 1,000-ft. ROW

This category includes two types of realignments that are both cataloged in the TAGS Rev. 2 to Rev. 4 Realignments table: moderate and large.

Moderate realignments – These realignments leave the 1,000-ft. ROW, but 82 percent of them stay within 1,000 feet of the edge of the JPO ROW (1,500 ft. from the JPO centerline), and 70 percent are less than 2 miles in length. Only one is greater than 7 miles in length. A typical example of a moderate realignment would be in the upper Dietrich River (Mile 175.02) where the JPO Rev. 2 alignment runs along the west side of the river. To avoid unstable slopes, the pipeline was realigned eastward across both the river and the Dalton Highway. Its length outside the 1000-ft. ROW is 0.6 mi. and its maximum distance from the edge of the ROW is 200 ft. Only four moderate realignments deviate more then 2,000 ft. from the edge of the JPO ROW. These latter are considered moderate because the new alignments remain within the original general terrain. Realignments which deviate outside of the JPO Rev. 2 alignment "landscape," e.g., to the other side of a sizeable lake, valley, or major topographic feature, are considered large realignments. There are fifty moderate realignments between Prudhoe Bay and Anderson Bay.

Large realignments – These realignments leave the 1,000-ft. ROW for greater distances in both length and offset, and were made because of a definite change of intent. An example would be at Galbraith Lake (Mile 133.43), where the JPO alignment is on the west side of the Atigun River Valley. At the request of agencies as well as YPC's Environmental Review Committee (ERC), to consolidate all disturbance on the east side of the valley in conjunction with TAPS, ANGTS, and the Dalton Highway, the Rev. 4 alignment was moved to the east side of the valley for a linear distance of 25.8 miles and a maximum distance from the edge of the JPO ROW of 2.5 miles. There are seven large realignments between Prudhoe Bay and Anderson Bay.

TAGS Rev. 2 to Rev. 4 Realignments Table

Milepost		Length (miles)		Max Dev	Alignment		
From	To	Total	Outside[1]	(> 500')[2]	Code	Approximate Location	Reason for Realignment
18.04	18.50	0.47	0.47	463	Moderate	Sagavanirktok Uplands	Avoid poor soils and conflicts with lakes and wetlands
25.63	30.44	4.82	4.82	520	Moderate	Sagavanirktok Uplands	Shorten alignment
70.25	70.62	0.38	0.38	287	Moderate	Sagwon	Reduce cross slopes
75.91	78.48	2.58	2.58	929	Moderate	Sagavanirktok Floodplain	Closer to highway to improve access and constructability
83.15	83.59	0.44	0.44	214	Moderate	Happy Valley	Reduce cross slopes and avoid a drainage
95.22	96.02	0.80	0.80	612	Moderate	Ice Cut Hill	Reduce cross slopes and improve constructability
119.45	125.77	6.32	0.00	-	Small	Slope Mountain	Consolidate all development on west side of highway
133.43	159.24	25.80	25.80	13,080	Large	Galbraith Lake	Consolidate all development on east side of Atigun River Valley
168.09	168.28	0.19	0.19	255	Moderate	Chandalar River	Reduce cross slopes and improve river crossing
174.02	174.15	0.13	0.13	178	Moderate	Chandalar Shelf	Reduce cross slopes on steep descent
175.02	176.13	1.11	0.60	200	Moderate	Upper Dietrich River	Avoid unstable slopes (landslide on west side of river)
178.82	179.35	0.53	0.53	66	Moderate	Dietrich River	Reduce cross slopes
205.12	206.78	1.66	0.52	426	Moderate	Sukakpak Mountain	Consolidate all development and avoid TAPS crossings
211.10	212.39	1.29	1.02	213	Moderate	Linda Creek	Closer to highway to improve access and constructability
216.96	218.20	1.24	1.24	116	Moderate	Nugget Creek	Closer to highway to improve access and constructability
222.11	222.51	0.39	0.39	307	Moderate	Bluff Gulch	Reduce cross slopes
223.93	226.80	2.87	0.92	147	Moderate	Minnie Creek	Reduce cross slopes and consolidate development
229.11	235.32	6.21	3.68	2,376	Moderate	Marion Creek	Avoid Marion Ck. Campground and improve access and constructability
243.43	246.30	2.87	1.91	548	Moderate	Cathedral Mountain	Reduce cross slopes and consolidate development
260.46	264.24	3.77	3.77	2,384	Moderate	Grayling Lake	Improve access and constructability and reduce visual impacts
288.44	290.59	2.15	1.57	228	Moderate	S. Fork Bonanza Creek	Reduce cross slopes and consolidate development
290.94	294.95	4.00	4.00	2,724	Moderate	Fish Creek	Reduce cross slopes and improve stream crossing
308.26	310.39	2.12	2.12	617	Moderate	Finger Mountain	Avoid new visitor nature interpretative center
316.62	323.59	6.98	5.82	601	Moderate	West Fork Dall Creek	Closer to highway to improve access and constructability
324.25	351.00	26.75	26.75	10,793	Large	Fort Hamlin Hills	Consolidate development and improve access and constructability
351.00	355.37	4.37	4.37	2,488	Large	Yukon River Crossing	Use existing Yukon River bridge pipe rack
364.14	370.69	6.56	6.56	4,655	Moderate	Isom Creek	Reduce cross slopes, avoid wetlands, improve access and constructability
374.79	375.61	0.82	0.82	265	Moderate	Hess Creek	Improve highway crossing
383.21	395.12	11.91	11.54	1,986	Moderate	Erickson Ck/Lost Ck	Reduce cross slopes and improve access and constructability
411.40	422.65	11.25	11.25	11,494	Large	TAPS PS#7, Globe Ck.	Consolidate development, avoid extreme terrain, and improve constructability
429.05	429.36	0.32	0.32	182	Moderate	Washington Creek	Reduce cross slopes

TAGS Rev. 2 to Rev. 4 Realignments Table

Milepost		Length (miles)		Max Dev	Alignment		
From	To	Total	Outside[1]	(> 500')[2]	Code	Approximate Location	Reason for Realignment
436.65	437.82	1.18	1.18	304	Moderate	Chatanika River	Reduce cross slopes
462.81	463.86	1.05	1.05	1,826	Moderate	Chena Lakes	Avoid flooded borrow pit
486.29	487.49	1.20	1.20	202	Moderate	Little Salcha River	Avoid GVEA intertie and avoid cross slopes
504.51	504.86	0.35	0.35	141	Moderate	Minton Creek	Reduce cross slopes
516.38	528.59	12.21	12.21	6,292	Large	Shaw Creek/Tanana River	Improve access/constructability, avoid Quartz Lk. area, improve Tanana crossing
528.78	531.65	2.86	2.86	593	Moderate	Delta Junction	Avoid actively farmed land and consolidate development
567.39	572.35	4.96	2.54	1,067	Moderate	Darling Creek	Reduce cross slopes
574.06	574.79	0.72	0.72	747	Moderate	Black Rapids	Reduce cross slopes
576.85	579.80	2.96	0.00	-	Small	Delta River	Reduce cross slopes
581.11	581.95	0.84	0.00	-	Small	TAPS PS#10	Reduce cross slopes and consolidate development
587.75	587.88	0.13	0.13	17	Moderate	Phelan Creek	Resolution error
590.02	616.24	26.22	26.22	17,914	Large	Summit Lake	Consolidate all development on east side of Summit Lake
639.48	640.43	0.95	0.95	385	Moderate	Hogan Hill	Reduce cross slopes
643.56	648.49	4.93	4.93	1,292	Moderate	Sourdough Creek	Avoid Native allotment
651.52	652.10	0.57	0.57	255	Moderate	Gulkana River	Improve river crossing and avoid wetlands
685.00	685.20	0.20	0.20	141	Moderate	Tazlina River	Avoid wetlands
697.97	711.00	13.03	13.03	10,298	Large	Willow Mountain/Lake	Consolidate development, improve constructability, reduce wildlife concerns
714.75	715.79	1.04	1.04	253	Moderate	Tonsina River	Reduce cross slopes
717.26	717.37	0.11	0.11	174	Moderate	Tonsina River	Avoid slope stability problems
726.95	727.28	0.33	0.33	221	Moderate	Little Tonsina River	Reduce cross slopes
731.64	731.88	0.23	0.23	96	Moderate	Tiekel River	Reduce cross slopes
734.14	735.35	1.21	1.21	593	Moderate	Tiekel River	Reduce cross slopes
739.76	739.84	0.07	0.07	166	Moderate	Tiekel River	Improve highway crossing
766.09	766.60	0.50	0.50	398	Moderate	Thompson Pass	Reduce cross slopes
767.51	767.85	0.34	0.34	277	Moderate	Thompson Pass	Improve descent from pass, reduce conflict at Blueberry Lake Recreation Area
771.61	771.90	0.29	0.29	404	Moderate	Wortmans	Avoid private land
782.37	782.53	0.16	0.16	173	Moderate	Lower Lowe River	Reduce cross slopes
783.44	783.65	0.21	0.21	108	Moderate	Lower Lowe River	Reduce cross slopes
794.15	796.05	1.90	1.90	1,133	Moderate	TAPS Marine Terminal	Improve terminal bypass

[1] Length outside 1,000-ft. ROW

[2] Maximum deviation from edge of 1,000-ft. ROW (i.e., distance greater than 500' from pipeline centerline)

RECEIVED
OFFICE

Alaskan Northwest Natural Gas Transportation Company

3100 - 707 - 8th Avenue S.W. Calgary, Alberta T2P 3W8

01 MAR -8 AM 5:44

March 6, 2001

Mr. William G. Britt, Jr.
State Pipeline Coordinator
411 West 4th Avenue, Suite 2C
Anchorage, Alaska 99501

VIA FAX: 907-272-0690
and COURIER

Dear Mr. Britt:

Re: Alaskan Northwest Natural Gas Transportation Company's Pending State Right-of-Way Lease Application

As you are aware, the Alaskan Northwest Natural Gas Transportation Company ("Alaska Northwest") a partnership which (as a successor to Alcan Pipeline Company) is the Company designated under United States and Canadian law as the company to construct and operate the Alaska portion of the Alaska Natural Gas Transportation System ("Alaska Highway Project"). That Project was approved pursuant to the Alaska Natural Gas Transportation Act of 1976 ("ANGTA") in the United States, the 1978 Northern Pipeline Act in Canada, and the 1977 Agreement Applicable to a Northern Natural Gas Pipeline between the two countries. Alaska Northwest, along with its Canadian Partner, Foothills Pipe Lines Ltd., has maintained the viability of the Alaska Highway Project for over twenty years. We remain dedicated to working with the owners of the Alaska North Slope natural gas to move those reserves to market in an expeditious manner.

As you are fully aware, after receiving in 1980 a grant of right-of-way across federal lands in Alaska, the Alaska Northwest filed in 1981 an application with the State of Alaska requesting a right-of-way lease across state lands. Prior to obtaining its requested right-of-way lease, Alaska Northwest placed the Alaska Highway Project on hold, including the acquisition of the state right-of-way lease, due to natural gas market conditions in the lower-48 states. Given the vast amount of work done and money expended on the right-of-way lease, Alaska Northwest decided to maintain the lease application in good standing so that it could be easily completed when the Project was remobilized. To that end, over the years, Alaska Northwest has done much work to keep its pending lease application current and to satisfy, among other things, issues that have arisen, draft lease stipulations and, pursuant to Alaska's Right-of-Way Leasing Act, the requirement that it have the technical and financial capability to take action. Specifically, as highlighted in the attached document, Alaska Northwest has continuously been active over the years regarding, among other things, the resolution of state right-of-way issues, the satisfaction of draft state right-of-way lease stipulations, project cost estimating, frost heave engineering and other technical work completed in support of the state right-of-way application and extension of the Project's Section 404 of the Clean Water Act permits. Alaska Northwest also has conducted

regular route surveillance and continues to pay lease rentals to the State for 152 miles of federal right-of-way transferred to the State.

While we recently have commenced discussions with your office regarding perfecting our pending state right-of-way lease application, we would now like to step that process up. For example, we have discussed with you the idea of doing a number of workshops. With this in mind, please consider this formal notice that we wish to continue with our application and in this regard, we are prepared to meet and discuss the Joint Pipeline Office's activities regarding (1) review of what Alaska Northwest has filed to date in support of its pending right-of-way lease application; and (2) the steps that need to be taken (and target dates for same) in order for Alaska Northwest to complete its application and procure in a timely fashion a right-of-lease across state lands, including discussions regarding the scope of the work to be done at the State level versus the Federal level.

In order to move this along, Terry Klatt from our office will attempt to arrange some time while you are in Calgary later on this week to meet and discuss the upcoming scope of work. Terry will call you to discuss your schedule and any questions you may have regarding this letter.

We look forward to working closely with you as we move toward full remobilization of the Project.

Yours truly,

John R. Ellwood
Project Manager, Alaskan Northwest Natural Gas Transportation Company

Attachments:

cc. Mr. Bruce M. Botelho, Attorney General
Mr. Pat Pourchot, Commissioner, Alaska Department of Natural Resources
Mr. Wilson Condon, Commissioner, Alaska Department of Revenue
Ken Freeman, Special Assistant for Business and Gasline Development, Governor's Office

JRE/dew

THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM'S STATE OF ALASKA RIGHT-OF-WAY LEASE APPLICATION CONTINUATION

POST-1982 ACTIONS TAKEN BY THE ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY IN SUPPORT OF THE CONTINUED VIABILITY OF THE STATE RIGHT-OF-WAY LEASE APPLICATION

Introduction

- After receiving in 1980 a grant of right-of-way across federal lands in Alaska, the Alaskan Northwest Natural Gas Transportation Company Partnership ("Alaska Northwest") filed in 1981 an application with the State of Alaska requesting a right-of-way lease across state lands. Prior to obtaining its requested right-of-way lease, Alaska Northwest placed the Alaska Natural Gas Transportation System project ("ANGTS") on hold, including the acquisition of the state right-of-way lease, due to natural gas market conditions in the lower-48 states. Given the vast amount of work done and money expended on the right-of-way lease, Alaska Northwest decided to maintain the lease application in good standing so that it could be easily continued when the Project was remobilized. To that end, over the years, Alaska Northwest has done much additional work to keep its pending lease application current.

Maintaining the Alaska Northwest Partnership

- Alaska Northwest has maintained approvals and authorizations in effect, continued to conduct engineering and other project feasibility studies and investigated the applicability of new technologies to reduce the cost of construction of the ANGTS.
- Thus, Alaska Northwest has done much work on the pending state right-of-way application in order to satisfy, among other things, issues that have arisen, draft lease stipulations and, pursuant to Alaska's Right-of-Way Leasing Act, the requirement that it have the technical and financial capability to take action.
- Foothills Pipe Lines Ltd ("Foothills"), co-owner of Alaska Northwest, has continued to communicate to state officials on a regular basis its on-going interest in the Project.

Resolution of State Right-Of-Way Issues

- Alaska Northwest satisfied all information requests made by Alaska Department Of Transportation ("ADOT") on use of the Yukon River Bridge for the gas pipeline crossing of the Yukon River. – 1983
- At the request of the ADOT, Alaska Northwest completed a "Thermal Effects Study" of gas pipeline construction effects on the Dalton Highway. - 1985
- Alaska Northwest and State of Alaska officials finalized the terms of an "Agreement on Highway Use, Maintenance and Repairs." – 1985
- Alaska Northwest submitted its Revision 4 pipeline alignment sheets, representing resolution of state and federal routing issues. – 1986

Satisfaction of Draft State Right-of-Way Lease Stipulations

- Alaska Northwest completed and obtained federal and state approval on 14 of the 25 stipulation 1.6.1 plans required by both the federal right-of-way grant and the draft state ROW lease. – 1985
- Alaska Northwest completed and obtained federal and state approval of the design criteria manuals for pipeline, compressor and meter stations, pipeline supervisory control system, and pipeline telecommunications. – 1985

Project Cost Estimating

- Two major re-estimates of Project costs have been completed, including that portion of the pipeline on state lands. – 1988, 2000

Frost Heave Engineering

- In support of the technical work required for the State right-of-way application, Alaska Northwest completed its initial phase of its extensive frost heave engineering program -- 1985.
- More than $125 million has been invested by Alaska Northwest in field, laboratory and engineering work, as well as development of the Frost Heave Design Criteria and Methodology, which was approved by state and federal officials.
- Through Foothills, Alaska Northwest participated in the partial reactivation of the Fairbanks Frost Heave Test facility in 1999, and continues to collect and analyze certain data from that site.

Additional Technical Work Completed In Support of the State Right-of-Way Application

- Alaska Northwest has expended more than $30 million in Alaska on the development of route base maps, drawings and surveys. -- 1985
- More than $77 million has been expended in Alaska by Alaska Northwest on the development of geo-technical data. -- 1985
- More than $19 million was expended by Alaska Northwest in Alaska on environmental-related data. – 1984

ANGTS Technological Advancements in Support of the State Right-of-way Application– 1993 - Present

ANGTS sponsors have continued to pursue technological advancements focused toward reducing project costs while maintaining environmental and safety standards, including such things as, among others:

- applied dense phase fluid transportation concept to ANGTS;
- dense phase work included hydraulic design, modeling and laboratory evaluation of dense phase fluid properties, plume dispersion and fracture control analysis;
- associated engineering work included technical capability of high strength steels, frost heave analysis of high strength/high pressure pipe, and preliminary design and costing of dense phase compressor stations and pipelines;
- frost heave engineering models developed from the frost heave engineering work have been continually upgraded over the last 15 years; and
- presented progress to North Slope Producers and Alaska state and federal officials, including 1997 testimony before the U.S. Senate Energy and Natural Resources Committee

Right-of-Way Lease Rentals

- Alaska Northwest has continued to pay lease rentals to the state for 152 miles of right-of-way that was granted by the federal government pursuant to a federal right-of-way grant and was subsequently transferred to state administration in1994.

Extension of Section 404 Permits - 1998

- Alaska Northwest applied for, and received extensions of, Section 404 permits from the Department of the Army. This included the granting of a "Certificate of Reasonable Assurance" from the State of Alaska Department of Environmental Conservation. These permits pertain mainly to right-of-way requested by Alaska Northwest in the state right-of-way lease application.

Reconnaissance Efforts

- The ANGTS sponsors' intent that the application for the state right-of-way lease remain viable and pending, and the Joint Pipeline Office's acknowledgment of the same, further is evidenced by the fact that, in 1992, 1994, 1996, and 1998, the ANGTS sponsors, with the cooperation and coordination of the Joint Pipeline Office, conducted surveillance activities on the granted federal right-of-way (including the portion transferred to the state) and the requested state right-of-way.

Work Product Submitted in Support of Application for State Right-of-way Lease

- The documents and work product submitted to the State in support of the right-of-way lease application have always been maintained on an active basis. Indeed, starting in 1983-1984, pursuant to a request from the State, Alaska Northwest maintained the State's ANGTS files under Alaska Northwest's temporary custody and at Alaska Northwest's expense in warehouse storage. In the early 1990's, such records were transferred back to the State Pipeline Coordinator's Office.
- Alaska Northwest has submitted to the State much of the work product in support of the right-of-way lease application on a confidential and proprietary basis. Because of the inherent commercial value of the work product submitted in support of the state right-of-way lease application, disclosure of the information contained in those materials would cause substantial competitive harm to the ANGTS sponsors and unjustly enrich other parties, including competitors interested in exploring and developing alternative pipeline projects.

TRANS-ALASKA GAS SYSTEM

CONDITIONAL RIGHT-OF-WAY LEASE

ADL 413342

Yukon Pacific Corporation

State of Alaska Department of Natural Resources

December 1988

CONDITIONAL

RIGHT-OF-WAY LEASE FOR THE TRANS-ALASKA GAS SYSTEM

ADL 413342

This CONDITIONAL LEASE is entered into and made effective this 10 day of December, 1988,

by the STATE OF ALASKA
acting through the Commissioner of the
Department of Natural Resources,

and by YUKON PACIFIC CORPORATION
whose address is
900 West Fifth Avenue, Suite 730,
Anchorage, Alaska 99501.

Note: Terms having special meaning are capitalized and are defined in Section 10 of this CONDITIONAL LEASE as well as incorporated by reference to Exhibit A, "Right-of-Way Lease for the Trans-Alaska Gas System, ADL 413342" (LEASE).

Section 1. CONDITIONAL LEASE.

Pursuant to AS 38.35 and the regulations promulgated thereunder, the COMMISSIONER has determined that the proposed CONDITIONAL Right-of-Way LEASE by the applicant, Yukon Pacific Corporation, is in the public interest provided that the terms and conditions of the CONDITIONAL LEASE are met. The requisite determinations required by the aforesaid statutes and regulations are contained in the administrative record of ADL 413342.

If the terms and conditions set forth in this CONDITIONAL LEASE are met within the specified time limits and prior to termination or revocation of this CONDITIONAL LEASE, it is the COMMISSIONER's decision that the LEASE attached as Exhibit A would be consistent with the public interest and will be granted subject to the provisions of AS 38.35.100.

Therefore, the application for a CONDITIONAL Right-of-Way LEASE is granted subject to the conditions listed in Section 2. Evidentiary Requirements to Proceed to Final Lease.

Section 2. Evidentiary Requirements to Proceed to Final Lease

A. The CONDITIONAL LESSEE shall provide PIPELINE alignment location and RELATED FACILITY site locations plotted on available large scale maps, where feasible, or on large scale (1 inch = 1,000 feet or greater) aerial photographs for review and approval of the COMMISSIONER for the purpose of locating and describing the Right-of-Way on STATE LAND. In addition, where required by the COMMISSIONER, the CONDITIONAL LESSEE shall field stake specific portions of the PIPELINE alignment or RELATED FACILITY site locations to the satisfaction of the COMMISSIONER. This information shall be submitted by the COMMISSIONER to the owners or agents of the TRANS-ALASKA PIPELINE SYSTEM, other authorized OIL or GAS transportation pipeline(s), or other existing or proposed FACILITIES pursuant to AS 38.05.945 and AS 38.05.035(e) for the purpose of identifying what portions of the PIPELINE or RELATED FACILITIES are PROXIMATE to existing or proposed FACILITIES. Those portions identified by such owners as being PROXIMATE to the PIPELINE and RELATED FACILITIES shall be reviewed and approved by the COMMISSIONER.

B. The CONDITIONAL LESSEE shall submit evidence of financial commitment to the COMMISSIONER sufficient to design and construct the proposed Trans-Alaska Gas System project. Such evidence shall include letters of intent for GAS sales, letters of intent for GAS purchase, and written preliminary commitments for construction financing. Additional evidence may include financial plans, a summary of project economics, and any other financial information as may be required by the COMMISSIONER.

C. The CONDITIONAL LESSEE shall submit the following technical information relating to the Trans-Alaska Gas System project:

(1) Project Development Schedule.

a. The CONDITIONAL LESSEE shall submit a Project Development Schedule to the COMMISSIONER for review. The Project Development Schedule shall address, at a minimum, the following:

1. sequence and approximate timing of all PRECONSTRUCTION activities;
2. submission of AUTHORIZATION-TO-PROCEED applications;
3. submission of all other permit applications;
4. environmental constraints on PRECONSTRUCTION scheduling; and,
5. submission of the items in Section 2. Evidentiary Requirements to Proceed to Final Lease.

b. The Project Development Schedule, required by Section 2.C.(1)a., shall be submitted with the scope and content to be MUTUALLY AGREED to by the COMMISSIONER and the CONDITIONAL LESSEE annually prior to September 1st for the purpose of preparing the State's budget for the subsequent fiscal year (July 1-June 30).

(2) Project Performance Standards. The CONDITIONAL LESSEE shall prepare and submit TAGS Project Performance Standards, to the COMMISSIONER for review and written approval, which shall define the envelope of constraints within which the DESIGN CRITERIA, FINAL DESIGN, CONSTRUCTION, OPERATION, and TERMINATION activities of the project will occur. The

COMMISSIONER and the CONDITIONAL LESSEE shall MUTUALLY AGREE upon the scope, content and schedule for submission of the Project Performance Standards.

(3) Project Plans and Programs

a. The CONDITIONAL LESSEE shall submit the following Project Plans and Programs to the COMMISSIONER for review and approval (such plans and programs may be combined and/or cross-referenced where appropriate):

1. Air Quality Permit Identification
2. Blasting
3. Camps
4. Cultural Resource Preservation
5. Environmental Briefings
6. Erosion and Sedimentation Control
7. Fire Control
8. Liquid Waste Management
9. Material Exploration and Extraction
10. OIL and HAZARDOUS SUBSTANCES Control, Cleanup, Disposal
11. Pesticides, Herbicides, Chemicals
12. Quality Assurance/Quality Control
13. RESTORATION
14. Solid Waste Management
15. Stream, River and Floodplain Crossings
16. Human-Carnivore Interaction
17. ACCESS ROADS, including Snow/Ice
18. Compressor Station Siting
19. Equipment and Material Storage
20. Water Quality
21. Noise
22. Road Proximity/Crossing
23. Pipeline Proximity/Crossing
24. Subsistence Resource Protection
25. Public Health, Safety, Welfare
26. Local Hire, Manpower Training, Alaska Business Utilization
27. Socioeconomic Impacts

b. The COMMISSIONER will review for approval the scope, content and schedule for submission of the Project Plans and Programs required in Section 2.C.(3).a.

c. The Project Plans and Programs listed in Section 2.C.(3).a. may be updated at intervals MUTUALLY AGREED upon by the CONDITIONAL LESSEE and the COMMISSIONER.

d. The Project Plan addressing, in part, local hire and manpower training, as required by Section 2.C.(3).a.26, shall include, at a minimum, job identification, job classes, training programs, job certification, where appropriate, and assurances of local hiring opportunities for qualified persons.

e. The Project Plans and Programs or specific Project Performance Standards listed in Sections 2.C.(2) and 2.C.(3) that may affect FACILITIES that are PROXIMATE to the proposed Trans-Alaska Gas System alignment, such as the TRANS-ALASKA PIPELINE SYSTEM, other authorized OIL or GAS transportation pipeline(s), PUBLIC

ROADS/HIGHWAYS, or the FACILITIES of other third party owners with valid existing rights on STATE LAND, shall be coordinated by the LESSEE with the respective owners. Evidence of coordination with such owners shall accompany the submission of applicable Project Performance Standards and the Project Plans and Programs.

(4) **CONCEPTUAL DESIGN.** Prior to being granted a LEASE, the CONDITIONAL LESSEE shall provide CONCEPTUAL DESIGN for the PIPELINE and RELATED FACILITIES for review and written approval of the COMMISSIONER. The COMMISSIONER and the CONDITIONAL LESSEE shall MUTUALLY AGREE upon the scope, content and schedule for submission of the CONCEPTUAL DESIGN.

(5) Lease Amendments Required for Project Definition

a. Gas Conditioning Facility. The CONDITIONAL LESSEE shall determine the means by which it will obtain GAS for transport. The CONDITIONAL LESSEE will provide letters of intent for GAS purchase agreements if the CONDITIONAL LESSEE will not be constructing and operating a Gas Conditioning Facility. If the CONDITIONAL LESSEE has determined that it will construct and operate a Gas Conditioning Facility, the CONDITIONAL LESSEE shall submit the following:

1. an application for amendment to the CONDITIONAL LEASE as a RELATED FACILITY authorized by AS 38.35;
2. suitable Project Performance Standards, as required by Section 2.C.(2);
3. a Gas Conditioning Facility project plan;
4. a CONCEPTUAL DESIGN as required by Section 2.C.(4);
5. location of the Gas Conditioning Facility site as required by Section 2.A.

b. ACCESS ROADS. The CONDITIONAL LESSEE shall determine the location of ACCESS ROADS required for the project and shall submit the following:

1. an application for amendment to the CONDITIONAL LEASE as a RELATED FACILITY authorized by AS 38.35;
2. suitable Project Performance Standards as required by Section 2.C.(2);
3. an ACCESS ROADS plan as required by Section 2.C.(3)a.17;
4. a CONCEPTUAL DESIGN as required by Section 2.C.(4);
5. location of the proposed ACCESS ROADS as required by Section 2.A.

c. Other Amendment. The addition of other RELATED FACILITIES, the locations of which are not identified yet, including but not limited to communication sites and spoil and WASTE disposal sites, or any substantial re-locations of any RELATED FACILITIES or substantial re-alignments of the PIPELINE shall require amendment to this CONDITIONAL LEASE.

(6) Specific Reports for Protection of the Public Interest

a. Yukon River Bridge. The CONDITIONAL LESSEE shall submit a report to the COMMISSIONER for review and approval that addresses, at a minimum, the basis for siting and impacts and alternatives related to CONSTRUCTION of a new bridge or use of the existing Yukon River bridge. The scope and content of the report shall be approved by the COMMISSIONER. Additionally, the CONDITIONAL LESSEE shall submit a CONCEPTUAL DESIGN for the Yukon River crossing.

b. Salcha River/Compressor Station #7 Siting. The CONDITIONAL LESSEE shall submi a report to the COMMISSIONER for review and approval that addresses, at a minimum, Compressor Station #7 siting, access to the PIPELINE and RELATED FACILITIES, material requirements, and identification of peregrine falcon nest sites in the Salcha River area. With respect to Compressor Station #7, the CONDITIONAL LESSEE shall address the basis for siting, alternative siting, noise levels anticipated on and adjacent to the Salcha River (including noise levels expected during winter conditions to -40 degrees F) that may impact recreation or private property, and mitigation of any impacts. The CONDITIONAL LESSEE shall address the identification of peregrine falcon nest sites with respect to Compressor Station #7 for consistency with federal protection measures for siting of permanent FACILITIES or with the Alaska Peregrine Falcon Recovery Plan. The scope and content of the report shall be approved by the COMMISSIONER.

c. Summit/Fielding Lakes--Phelan Creek to One Mile Creek. The CONDITIONAL LESSEE shall submit a report to the COMMISSIONER for review and approval that addresses, at a minimum, the basis for siting, alternative routing along the east side of Summit Lake, negative versus positive impacts of the PIPELINE route on the west side of Summit Lake from Phelan Creek to the proposed Richardson Highway crossing south of One Mile Creek, and the upper Gulkana River crossing. With respect to the Gulkana River, the CONDITIONAL LESSEE shall demonstrate protection of fisheries resources including minimization of siltation, protection of water supply for the fish incubation facility, and minimization of altered groundwater or surface flow or altered temperature of such flows. The scope and content of the report shall be approved by the COMMISSIONER. Additionally, the CONDITIONAL LESSEE shall submit CONCEPTUAL DESIGN for the PIPELINE from, and including, the upper Gulkana River crossing south to the proposed Richardson Highway crossing.

d. Hogan Hill/Compressor Station #9/Sourdough Creek Construction Camp Siting. The CONDITIONAL LESSEE shall submit a report to the COMMISSIONER for review and approval that addresses, at a minimum, the basis for siting, alternative siting of FACILITIES, and identification of impacts and proposed mitigation, including scheduling of PRECONSTRUCTION, CONSTRUCTION, OPERATION, and TERMINATION activities, relating to movements of the Nelchina Caribou Herd. The scope and content of the report shall be approved by the COMMISSIONER.

e. Lowe River/Canyon Slough Complex. The CONDITIONAL LESSEE shall submit a report to the COMMISSIONER for review and approval that addresses, at a minimum, the basis for siting, alternative routing, the specific impacts of crossing the Canyon Slough complex, and specific mitigation measures to be incorporated into planning and design.

f. Lowe River/Keystone Canyon. The CONDITIONAL LESSEE shall submit a report to the COMMISSIONER for review and approval addressing, at a minimum, geologic hazards present in Keystone Canyon (including outburst floods from Sheep Creek), the proximity of

the Richardson Highway, the basis for siting, alternative routing and proposed mitigation. The scope and content of the report shall be approved by the COMMISSIONER. Additionally, the CONDITIONAL LESSEE shall submit CONCEPTUAL DESIGN for the PIPELINE route through Keystone Canyon.

g. The CONDITIONAL LESSEE shall submit a report to the COMMISSIONER for review and approval that addresses the Marine Terminal and public marine access within Anderson Bay.

h. The CONDITIONAL LESSEE shall submit a report to the COMMISSIONER for review and approval addressing the impact of PRECONSTRUCTION and CONSTRUCTION activities on tourism in the Valdez area, including a consideration of the impact such activities would have on highway travel through Keystone Canyon.

(7) **Specific Agreements for Protection of the Public Interest**

a. **PUBLIC ROADS/HIGHWAYS.** The CONDITIONAL LESSEE shall agree to reimburse the STATE for damages to PUBLIC ROADS/HIGHWAYS or airports due to construction and/or overweight loads utilized by the CONDITIONAL LESSEE during PRECONSTRUCTION, CONSTRUCTION, OPERATION, and TERMINATION of the PIPELINE SYSTEM.

Section 3. Nature of Interest.

A. This CONDITIONAL LEASE conveys no interest in land, property or resources of the STATE, or any preference or priority rights to a particular right-of-way or alignment. The issuance of a CONDITIONAL LEASE does not prevent the COMMISSIONER from issuing other conditional or final leases for the same Right-of-Way. No CONSTRUCTION activities are authorized by this CONDITIONAL LEASE. Upon receiving an application for any other conditional right-of-way lease or authorization that would vest a property right, for the same right-of-way, the Department of Natural Resources shall consult with the CONDITIONAL LESSEE and offer an opportunity to comment. Such comments shall be given due deference to the same degree as a State agency in the Department of Natural Resources' deliberations as to whether that application is in the best interest of the STATE .

B. Any future administrative decision made by the State of Alaska that affects the title to the property described by this CONDITIONAL LEASE is subject to administrative and legal appeal made pursuant to State statutes.

C. This CONDITIONAL LEASE applies to the proposed Right-of-Way on STATE LAND for a PIPELINE and RELATED FACILITIES as generally located and described by the documents listed in Exhibit C of the LEASE (Exhibit A) the purpose of which is for the PRECONSTRUCTION, CONSTRUCTION, OPERATION, and TERMINATION of one (1) 36-inch diameter natural GAS transportation PIPELINE and RELATED FACILITIES. The width of the proposed Right-of-Way shall not exceed 1,000 feet, 500 feet on either side of the proposed centerline, except where the dimensions of the Right-of-Way shall accommodate the LNG Plant and Marine Terminal, and compressor stations, and shall accommodate any other RELATED FACILITIES outside the boundaries of the proposed Right-of-Way that are authorized by amendment to this LEASE. Subsequent to submission of the alignment/location maps and aerial photographs required by Section 2.A of the CONDITIONAL LEASE, the Right-of-Way boundaries shall be 500 feet on either side of the proposed PIPELINE centerline and the proposed boundaries established for the RELATED FACILITIES.

D. PRECONSTRUCTION activities may be authorized under this CONDITIONAL LEASE. Prior to initiating any field activity on STATE LAND pursuant to this CONDITIONAL LEASE, the CONDITIONAL LESSEE must possess a valid AUTHORIZATION-TO-PROCEED issued by the COMMISSIONER. Each AUTHORIZATION-TO-PROCEED shall authorize only PRECONSTRUCTION field activities specific to that permit. An AUTHORIZATION-TO-PROCEED may contain such site-specific terms and conditions as the COMMISSIONER finds necessary to implement the provisions of this CONDITIONAL LEASE, and the CONDITIONAL LESSEE shall comply in all respects with the provisions of the AUTHORIZATION-TO-PROCEED. Each application for an AUTHORIZATION-TO-PROCEED shall be accompanied by the following:

(1) a description of the proposed activity and its location, including access routes;

(2) scaled maps or drawings depicting the exact location of the proposed activities, PROXIMATE existing FACILITIES of third party owners with valid existing rights on STATE LAND, including the TRANS-ALASKA PIPELINE SYSTEM, drainages, trails, or other access routes, and other pertinent information sufficient for identification of potential conflicts with existing land uses and state and private property interests;

(3) proposed measures for prevention of significant adverse environmental impact;

(4) proposed RESTORATION procedures for areas of surface disturbance;

(5) proposed measures for protecting subsistence resources and their uses in the vicinity of the proposed activity;

(6) a separate analysis of the effects of the proposed activity and written evidence of coordination with any third party owners with valid existing rights on STATE LAND, including the TRANS-ALASKA PIPELINE SYSTEM, or other authorized OIL or GAS transportation pipeline whose FACILITIES are PROXIMATE to such PRECONSTRUCTION activities.

Section 4. Duration of CONDITIONAL LEASE.

A. This CONDITIONAL LEASE and all rights associated with this CONDITIONAL LEASE or with the COMMISSIONER's finding pursuant to AS 38.35.100(b) shall automatically terminate at midnight on the first day following ten (10) years from the date of signature of this CONDITIONAL LEASE, or unless prior to that date it is relinquished, abandoned or otherwise terminated pursuant to the provisions of this CONDITIONAL LEASE or any applicable laws or regulations, or unless by that time the COMMISSIONER has determined in a written finding that the CONDITIONAL LESSEE is fit, willing and able to perform the transportation or other acts proposed in a manner that will be required by the present and future public interest, in a manner consistent with the conditions set out herein and with the applicable laws which are then in effect.

B. Upon request of the CONDITIONAL LESSEE, the COMMISSIONER may renew the CONDITIONAL LEASE as long as the CONDITIONAL LESSEE is in full compliance with the provisions of this CONDITIONAL LEASE and State and Federal laws.

C. This CONDITIONAL LEASE may be revoked by order of the COMMISSIONER, without compensation, at any time the COMMISSIONER determines that the applicant or CONDITIONAL LESSEE will not be fit, willing and able to perform during the ten (10) year term of this lease or whenever another applicant or conditional lessee is determined to be fit, willing, and able to perform under an application or lease of all or part of the Right-of-Way.

D. Upon expiration, relinquishment, abandonment, or other TERMINATION, the provisions of this CONDITIONAL LEASE, intended for the benefit of the STATE and the public, shall continue in effect and shall be binding on the CONDITIONAL LESSEE, or the CONDITIONAL LESSEE's successors and assigns, until the CONDITIONAL LESSEE has fully performed its respective obligations and liabilities accruing before or on account of the expiration, relinquishment, abandonment, or other TERMINATION of the CONDITIONAL LEASE.

E. Prior to expiration, relinquishment, abandonment, or other TERMINATION of the CONDITIONAL LEASE, the CONDITIONAL LESSEE shall remove all temporary and permanent improvements from STATE LAND and shall RESTORE such land, unless otherwise approved by the COMMISSIONER, within a time period specified by the COMMISSIONER.

Section 5. Transfer, Assignment or other Disposition.

A. The CONDITIONAL LESSEE will not transfer, assign, pledge, or dispose of in any manner, directly or indirectly, or by transfer of control of the CONDITIONAL LESSEE, its interest in this CONDITIONAL LEASE, or any rights under this CONDITIONAL LEASE or any rights to the PIPELINE SYSTEM subject to this CONDITIONAL LEASE to any person, except to the extent that the COMMISSIONER authorizes, in a written finding substantiating a decision to allow the transfer, after consideration of protection of the public interest. The CONDITIONAL LESSEE shall not allow the transfer of control of or redistribution of interests in the CONDITIONAL LESSEE without the approval of the COMMISSIONER; as used in this Subsection "transfer of control of the CONDITIONAL LESSEE" means 30 percent or more, in aggregate, of ownership interest in the CONDITIONAL LESSEE in one or more transactions, to one or more persons, by one or more persons. The COMMISSIONER shall not unreasonably withhold consent to the transfer, assignment or disposal. An unapproved transfer does not relieve the CONDITIONAL LESSEE of an obligation assumed under the CONDITIONAL LEASE, is ineffective to transfer interests in and obligations under the CONDITIONAL LEASE, and constitutes a default under the CONDITIONAL LEASE.

B. With respect to any request for transfer under Section 5.A., the COMMISSIONER shall consider whether the proposed transferee will be fit, willing and able to perform the transportation of natural GAS proposed under the terms and conditions established in the CONDITIONAL LEASE and whether the transfer is in the public interest. The COMMISSIONER may impose additional terms and conditions on the transferee that the COMMISSIONER considers in the public interest.

C. A transfer, pursuant to Section 5.A., in whole or in part, of the CONDITIONAL LESSEE's right, title and interest in the Right-of-Way and this CONDITIONAL LEASE shall constitute a release of the CONDITIONAL LESSEE's liabilities and obligations (accrued, contingent or otherwise) to the STATE under this CONDITIONAL LEASE only to the extent and limit that the transferee unconditionally assumes with permission of the COMMISSIONER the performance and observance of each such liability and obligation, and provides bonding and insurance to assure such performance and observance of such liabilities and obligation.

Section 6. Indemnification and Liability

A. The indemnification and liability terms and conditions in Sections 7 and 8 of the LEASE (Exhibit A) are hereby incorporated into and made part of the CONDITIONAL LEASE.

Section 7. Bonding

A. Initially, the CONDITIONAL LESSEE shall furnish the STATE a surety bond or other security of such type and on such terms and conditions as are acceptable to the COMMISSIONER, in the principal amount of one hundred fifty thousand dollars ($150,000). Prior to issuance of the first AUTHORIZATION-TO- PROCEED, the CONDITIONAL LESSEE shall furnish such bonding to the STATE, as acceptable to the COMMISSIONER, in the principal amount of one million dollars ($1,000,000). Said bond or other security shall be maintained in force and effect in the full principal amount, or in such reduced amount as may be approved by the COMMISSIONER, at all times during the term of the CONDITIONAL LEASE and until released in writing by the COMMISSIONER. Such release will not be unreasonably withheld upon expiration of the terms of this CONDITIONAL LEASE, including any renewals of this CONDITIONAL LEASE, and completion of the CONDITIONAL LESSEE's obligations under this CONDITIONAL LEASE and applicable law.

B. Said bond or other security shall be security for payment of any sums owing to the STATE pursuant to the provisions of Section 12, Right of the STATE to Perform, of the LEASE (Exhibit A).

C. These requirements are in addition to all other requirements of law, and are not intended to affect, nor are they intended to limit in any way, the CONDITIONAL LESSEE's liability under any provisions of law.

D. The COMMISSIONER reserves the right to require additional security from the CONDITIONAL LESSEE if at any time the COMMISSIONER determines it necessary in connection with the CONSTRUCTION, OPERATION or TERMINATION of the PIPELINE SYSTEM.

Section 8. Insurance

A. Without limiting CONDITIONAL LESSEE's indemnification, the CONDITIONAL LESSEE hereby agrees to provide and maintain in force throughout the term of this CONDITIONAL LEASE liability and property damage insurance from a company licensed to do business in the state or furnish other security or undertaking upon the terms and conditions the COMMISSIONER considers necessary if the COMMISSIONER finds that the net assets of the CONDITIONAL LESSEE are insufficient to protect the public from damage for which the CONDITIONAL LESSEE may be liable arising out of the PRECONSTRUCTION, CONSTRUCTION, OPERATION or TERMINATION of the PIPELINE, such as: comprehensive general liability including premises, operations, independent contractors, products and completed operations liability including contractual liability covering the CONDITIONAL LESSEE's indemnification obligation under Section 7 of the LEASE (Exhibit A), broad form property damage, pollution liability, explosion, collapse and underground (XCU), and fire legal liability endorsements, owned and non-owned (leased or hired) automobile, aircraft and watercraft liability, and architect and engineer professional errors and omissions. Coverage shall, to the reasonable satisfaction of the COMMISSIONER, insure the CONDITIONAL LESSEE's liabilities for accidental occurrences imposed on it by operation of the requirement for indemnification of the STATE contained in this CONDITIONAL LEASE. Coverage shall be obtained from a carrier with a rating acceptable to the COMMISSIONER and shall be on an "occurrence" basis. The STATE shall be added to the above-described policies as an additional insured with respect to such liabilities. Initially, coverage shall be in the minimal amount of five million dollars ($5,000,000) per occurrence. Prior to the issuance of the first AUTHORIZATION-TO-PROCEED, coverage shall be in the minimal amount of $150 million ($150,000,000) combined single limit per occurrence.

B. In addition, the CONDITIONAL LESSEE shall provide and maintain, for all employees of the CONDITIONAL LESSEE engaged in work under this CONDITIONAL LEASE, Workers' Compensation Insurance as required by AS 23.30. The CONDITIONAL LESSEE shall be responsible for Workers' Compensation Insurance for any contractor or subcontractor who directly or indirectly provides services under

this CONDITIONAL LEASE. This coverage must include employer's liability protection not less than $1,000,000 per occurrence. The insurer shall agree to waive all rights of subrogation against the STATE, its officers, agents, and employees for losses arising from the leased premises.

C. Certificates of insurance must be furnished to the COMMISSIONER. The required insurance is subject to annual review and adjustment by the COMMISSIONER, who may require reasonable increases based on increased risk.

D. The CONDITIONAL LESSEE's insurance coverage shall be primary insurance as respects the STATE, its officers, agents and employees. Any insurance or self insurance maintained by the STATE shall be excess of the CONDITIONAL LESSEE's insurance and shall not contribute with it.

Section 9. Incorporation by Reference of Terms and Conditions; Changes in Conditions

A. The terms and conditions as referenced below that are to be imposed on the LESSEE in the LEASE are hereby imposed on the CONDITIONAL LESSEE and are incorporated into and made a part of the CONDITIONAL LEASE. Where the terms and conditions reference LESSEE and LEASE in the "Right-of-Way Lease for the Trans-Alaska Gas System" (Exhibit A), they mean CONDITIONAL LESSEE and CONDITIONAL LEASE in the CONDITIONAL LEASE.

(1)	Section 5	Reservation of Certain Rights to the STATE
(2)	Section 12	Right of the STATE to Perform
(3)	Section 13	Books, Accounts and Records; Access to Property and Records
(4)	Section 14	Appointment of Agent for Service of Process
(5)	Section 15	Reimbursement of STATE Expenses
(6)	Section 16	Prevention and Abatement
(7)	Section 18	Orders, Notices and Other Documents
(8)	Section 19	Compliance with ATP/NTP AUTHORIZATIONS
(9)	Section 20	Temporary Suspension Orders
(10)	Section 21	Appeal Procedure
(11)	Section 23	Involuntary termination of Lease; Breaches, excluding Section 23.A.
(12)	Section 24	Prevalence of Law
(13)	Section 25	Remedies Cumulative; Equitable Relief
(14)	Section 26	Waiver Not Continuing
(15)	Section 27	Rights of Third Parties
(16)	Section 28	LEASE Not a Waiver of Any State Statutory Regulatory Power
(17)	Section 29	Section Headings
(18)	Section 32	Partial Invalidity
(19)	STIPULATION 1.1	Definitions
(20)	STIPULATION 1.2	Responsibilities
(21)	STIPULATION 1.3	Authority of Representatives of the COMMISSIONER and of Agent of the LESSEE
(22)	STIPULATION 1.4	Field Activities
(23)	STIPULATION 1.11	Quality Assurance and Control
(24)	STIPULATION 1.12	Surveillance and Maintenance
(25)	STIPULATION 1.13	Public and Private Improvements
(26)	STIPULATION 1.14	Health and Safety
(27)	STIPULATION 1.15	Survey Requirements
(28)	STIPULATION 1.16.1	Public Access
(29)	STIPULATION 1.17	Fire Prevention and Suppression
(30)	STIPULATION 1.18	Communications

(31) STIPULATION 1.19 Cultural Resources
(32) STIPULATION 1.20 Hunting, Fishing, Trapping
(33) STIPULATION 1.21 Changes in Conditions
(34) All of Section 2, Environmental STIPULATIONS
(35) All of Section 3, Technical STIPULATIONS

B. If there is a significant change in the conditions which necessitates additional terms to protect the public interest, the COMMISSIONER may require the CONDITIONAL LESSEE to agree to additional terms that the COMMISSIONER finds to be in the public interest prior to conversion to a LEASE.

Section 10. Definition of Terms

Terms having special meaning in this CONDITIONAL LEASE document and in those provisions of the LEASE document that are incorporated into and made part of the CONDITIONAL LEASE as referenced in Section 10 are capitalized and are defined in this Section and in STIPULATION 1.1, "Definitions" (Exhibit A of the LEASE).

A. COMMISSIONER means the Commissioner of the Department of Natural Resources, State of Alaska, or the Commissioner's appointed designee(s).

B. CONDITIONAL LEASE means the instrument conditionally granting a Right-of-Way for pipeline purpose pursuant to AS 38.35 to the CONDITIONAL LESSEE, but granting no rights, including preference or priority.

C. CONDITIONAL LESSEE means Yukon Pacific Corporation or its respective successors or assigns as authorized pursuant to Section 5 of the CONDITIONAL LEASE.

D. LEASE means (1) an instrument granting a leasehold interest in the Right-of-Way for the Trans-Alaska Gas System to Yukon Pacific Corporation for the purpose of PRECONSTRUCTION, CONSTRUCTION, OPERATION, and TERMINATION of the PIPELINE pursuant to AS 38.35, and (2) Exhibit A, "Right-of-Way Lease for the Trans-Alaska Gas System, ADL 413342 (unsigned).

Section 11. Exhibits

Exhibit A: Right-of-Way Lease for the Trans-Alaska Gas System, ADL 413342 (LEASE--unsigned).

Section 12. Authority to Enter Agreement

The CONDITIONAL LESSEE represents and warrants to the STATE that it is duly authorized and empowered under the applicable laws of the State of Alaska to enter into and perform this CONDITIONAL LEASE in accordance with the provisions of this CONDITIONAL LEASE.

Section 13. Partial Invalidity

If any part of this CONDITIONAL LEASE is held invalid or unenforceable, the remainder of this CONDITIONAL LEASE shall not be affected and shall be valid and enforced to the fullest extent permitted by law.

Section 14. Acceptance of LEASE

The CONDITIONAL LESSEE's execution of this CONDITIONAL LEASE signifies acceptance of the terms and conditions contained herein. Such acceptance constitutes an agreement between the CONDITIONAL LESSEE and the STATE that the LESSEE, together with the CONDITIONAL LESSEE's respective agents, employees, contractors and subcontractors (at any tier), shall comply with all terms and conditions contained in the CONDITIONAL LEASE and all applicable laws and regulations.

IN WITNESS WHEREOF, the parties hereto have duly executed this CONDITIONAL LEASE as of the first written date.

STATE OF ALASKA

By: Judith M. Brady

Judith M. Brady
COMMISSIONER
Department of Natural Resources

Date: Dec. 10, 1988

YUKON PACIFIC CORPORATION

By: Howard D. Griffith

Howard D. Griffith
President and Chief Executive Officer
YUKON PACIFIC CORPORATION

Date: Dec 10, 1988

Attested by:

Steve Cowper
Governor
State of Alaska

State of Alaska)
) ss
)

The foregoing instrument was acknowledged before me this 10th day of December, 1988, by Howard D Gruffett, President of YUKON PACIFIC CORPORATION.

Betty D. Adkison
Notary Public in and for the State of Alaska
My Commission Expires: February 23rd, 1991

STATE OF ALASKA)
) ss
Third Judicial District)

THIS IS TO CERTIFY that on this 10th day of December, 1988, before me personally appeared Judith M Brady, the COMMISSIONER of the Department of Natural Resources of the State of Alaska, who executed the foregoing instrument and acknowledged voluntarily signing the same.

Betty D. Adkison
Notary Public in and for the State of Alaska
My Commission Expires: February 23rd, 1991

RENEWAL OF THE CONDITIONAL RIGHT-OF-WAY LEASE FOR THE TRANS-ALASKA GAS SYSTEM (TAGS) (ADL 413342)

This renewal of the Conditional Right-of-Way Lease (CONDITIONAL LEASE) for the Trans-Alaska Gas System is made and entered into, and becomes effective this **11th** day of **December, 1998** by and between the State of Alaska acting through the COMMISSIONER of the Department of Natural Resources and Yukon Pacific Company, LP, acting through the President and Chief Executive Officer of Yukon Pacific Corporation.

Whereas, Yukon Pacific Corporation requested renewal of the CONDITIONAL LEASE for the Trans-Alaska Gas System for an additional lease term of ten (10) years pursuant to Section 4(B) of the CONDITIONAL LEASE; and the COMMISSIONER has determined that Yukon Pacific Corporation is in full compliance with the provisions of the CONDITIONAL LEASE and State and Federal laws.

Now, therefore, the parties agree that the CONDITIONAL LEASE is renewed for ten (10) years beginning on December 11, 1998 and expiring at midnight on December 11, 2008.

The parties further agree that Section 4 (B) of the CONDITIONAL LEASE shall be amended effective December 12, 1998 to read as follows:

> "Upon request of the CONDITIONAL LESSEE, the COMMISSIONER may renew the CONDITIONAL LEASE as long as the CONDITIONAL LESSEE is in full compliance with the provisions of this CONDITIONAL LEASE and State and Federal laws and provided that the CONDITIONAL LESSEE can demonstrate that substantial progress has been made toward a determination that the CONDITIONAL LESSEE is fit, willing and able to perform the transportation or other acts proposed in accordance with the provisions of AS 38.35.100 (a)."

All terms, covenants and conditions to the CONDITIONAL LEASE shall remain in full force and effect.

IN WITNESS WHEREOF, the parties have executed this renewal as of the date first written above.

STATE OF ALASKA

John T. Shively
Commissioner
Department of Natural Resources

YUKON PACIFIC CORPORATION

Jeff B. Lowenfels
President and Chief Executive Officer
Yukon Pacific Corporation

STATE OF ALASKA)
)ss.
THIRD JUDICIAL DISTRICT)

This is to certify that on the 9th day of December, 1998, before me, personally appeared John T. Shively, Commissioner of the Department of Natural Resources of the State of Alaska, who executed the foregoing renewal and acknowledged voluntarily signing the same.

Sharon Turnacden
Notary Public in and for the State of Alaska
My Commission expires My Commission Expires: February 12, 2001

STATE OF ALASKA)
)ss.
THIRD JUDICIAL DISTRICT)

This is to certify that on the 10th day of December, 1998, before me, personally appeared Jeff B. Lowenfels, the President and Chief Executive Officer of Yukon Pacific Corporation, who executed the foregoing renewal and acknowledged voluntarily signing the same.

Notary Public in and for the State of Alaska
My Commission expires Sept 8, 1999

TONY KNOWLES
GOVERNOR
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STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

ADMINISTRATIVE ORDER NO. 187

I, Tony Knowles, Governor of the State of Alaska, under the authority of art. III, secs. 1 and 24, of the Alaska Constitution and AS 44.17.060, name the commissioner of the Department of Natural Resources, through the commissioner's designee, the state pipeline coordinator, as the coordinator of state permits, authorizations, and oversight of pipelines designed to transport natural gas from the Alaska North Slope to market ("Gas Pipelines"). This Order covers the permitting, authorization, and oversight activities of Gas Pipelines by the Departments of Natural Resources, Environmental Conservation, Fish and Game, Transportation and Public Facilities, Labor and Workforce Development, Public Safety, and by the Division of Governmental Coordination ("Designated Agencies"). This Order may be amended to cover the permitting, authorization, and oversight activities of other agencies in the future as necessary and directed by future administrative orders of the Governor. This Order outlines the processes and responsibilities of the Designated Agencies with regard to state permits, authorizations, and oversight related to the preconstruction and construction of Gas Pipelines.

Nothing in this Order affects the responsibilities of state agencies that do not involve permits, authorizations, and oversight of Gas Pipelines, including advocacy by the Department of Law before the Federal Energy Regulatory Commission, or the development of fiscal terms by the Department of Revenue under AS 43.82.

Nothing in this Order re-assigns the responsibility of coordinating Alaska Coastal Management Program consistency reviews under AS 44.19.145 and 6 AAC 50 away from the Division of Governmental Coordination, Office of Management and Budget.

FINDINGS

1. It is in the best interest of the people of Alaska and the nation that Alaska's North Slope natural gas be expeditiously transported to market in a manner that makes the maximum contribution to the development and standard of living of the residents of our state. It is in the best interest of the people of Alaska and the nation that Gas Pipelines be designed and constructed in a safe and environmentally sound manner.

2. It is desirable that the State of Alaska have a unified voice representing its interests in dealings with Canadian and federal agencies, gas owners, pipeline companies, and contractors related to permitting, authorization, and oversight of Gas Pipelines. It is also desirable that the state have a single point of contact for permits, authorizations, and oversight of Gas Pipelines to ensure coordination among state, federal, and international authorizing agencies and, if appropriate, to develop substantially similar terms and conditions in pipeline documents.

3. Permitting, authorization, and oversight of Gas Pipelines involves many state agencies. A coordinated state approval and oversight process for Gas Pipelines that provides for internal alignment and dispute resolution is necessary. Internal alignment fosters efficiency in state permitting, approval, and oversight functions.

4. It is in the best interest of the people of Alaska to utilize existing government structures and processes to the maximum extent possible, optimize state pipeline expertise and performance, and minimize impacts to ongoing functions of government. The State Pipeline Coordinator's Office in the Department of Natural Resources (SPCO) is the appropriate lead and single point of contact for the permitting, authorization, and oversight of proposals for Gas Pipelines.

ORDER

To further these findings, I, Tony Knowles, Governor of the State of Alaska, order and declare the following:

1. A Gas Pipelines Cabinet is established, comprised of the commissioners of the Departments of Natural Resources, Environmental Conservation, Fish and Game, Revenue, Transportation and Public Facilities, Labor and Workforce Development, and Community and Economic Development; the director of the Division of Governmental Coordination; the Governor's Office Washington, D.C. Director; and the Attorney General. The commissioner of the Department of Natural Resources will chair the Gas Pipelines Cabinet.

2. The commissioner of the Department of Natural Resources, through the state pipeline coordinator (SPC), is the lead official for state communication and coordination with appropriate federal and Canadian agencies related to permitting, authorization, and oversight of Gas Pipelines, including routing, design, and construction.

3. The SPC is the lead official for coordinating state permitting, authorization, and oversight by Designated Agencies related to routing, design, and construction of Gas Pipelines. The SPC shall establish and maintain a Gas Pipelines Group within the SPCO to coordinate actions by Designated Agencies related to Gas Pipelines.

4. Each Designated Agency shall appoint a liaison officer who will report directly to the head of the Designated Agency, be assigned to the Gas Pipelines Group, and be located in the Gas Pipelines Group offices established by the SPC. Liaison officers shall serve as a single point of contact representing their Designated Agencies in matters relating to permitting, authorization, and oversight of Gas Pipelines during the preconstruction and construction phases. To the maximum extent consistent with applicable law, Designated Agencies shall delegate signatory authority to their liaison officers for issuance of permits and authorizations during preconstruction and construction phases.

5. Liaison officers shall be available to manage and perform work necessary to process permits and authorizations for Gas Pipelines by their Designated Agency; assist as necessary with permits and authorizations by other Designated Agencies; manage and perform work necessary to oversee construction of Gas Pipelines; and provide other necessary technical assistance to the SPC in their areas of expertise.

6. Liaison officers shall provide annual work plans for accomplishing the tasks outlined in paragraph 5 of this Order to the SPC for approval. The work plans shall include schedules, budgets, and staffing plans for permitting, authorization, and oversight work. Liaison officers shall monitor progress against their work plans and provide periodic reports to the SPC.

7. Staff hired by individual Designated Agencies for the Gas Pipelines Group are under the supervision of the liaison officer for the Designated Agency. Staff providing support from a Designated Agency's regional or central office will continue to work for their supervisor in the Designated Agency.

8. Liaison officers shall manage their Designated Agency's administrative functions that are directly related to their agency's participation in the Gas Pipelines Group, including maintaining agency files. Each Designated Agency shall keep a full set of files at the office of the Gas Pipelines Group on all aspects of its activities related to Gas Pipelines.

9. Liaison officers shall provide copies of all applications and requests for permits and authorizations related to preconstruction and construction of Gas Pipelines to the SPC. Each liaison officer shall coordinate with the SPC public notices and other legally required public hearing processes related to their agency's activities. All permits and authorizations issued by Designated Agencies related to Gas Pipelines preconstruction and construction activities shall be processed in the Gas Pipelines Group. Liaison officers shall provide copies of proposed permits and authorizations to the SPC for review and comment, and shall provide copies of permits and authorizations issued.

10. Each liaison officer shall, to the extent allowed by law and whenever feasible, consult with the SPC and consider the SPC's advice before taking enforcement actions by the Designated Agencies related to Gas Pipelines preconstruction and construction. This provision does not limit Designated Agencies' enforcement authorities or the exercise of those authorities.

11. The SPC shall establish preconstruction and construction field teams that the SPC determines, after consultation with affected agencies, are necessary for data gathering and oversight. Such teams may be composed of staff from a number of Designated Agencies and other state agencies. Responsibilities and authorities of affected state agencies may, consistent with law and after consultation with those agencies, be delegated to team members regardless of their agency affiliation.

12. Between the effective date of this Order and the date of execution of a reimbursement memorandum between the SPC and a Gas Pipelines sponsor, all Designated Agency funding requests associated with Gas Pipelines activities will be handled through the normal budget supplement and increment process coordinated by the Department of Natural Resources.

13. In order to develop a consolidated budget request, all Designated Agencies shall prepare and submit to the SPC an annual budget request for all appropriations, including costs reimbursed under AS 38.35.140(b) and permitting fees identified in statute or regulation, associated with Gas Pipelines projects. After review and approval by the SPC, the budget requests will be consolidated and submitted by the Department of Natural Resources through the budget review process. Gas Pipelines work by Designated Agencies may not be budgeted in the Executive Budget submitted to the legislature except through this process. Upon approval of the budget, and appropriation by the legislature, the SPC shall negotiate reimbursable services agreements with Designated Agencies to cover the approved costs associated with Gas Pipelines preconstruction and construction activities and shall ensure that reimbursement is secured promptly for costs incurred under approved appropriations.

14. If a Designated Agency requires additional staff position(s) to carry out its responsibilities, the agency shall, with the concurrence of the SPC as to appropriation, appoint additional staff.

15. In the event of a dispute between Designated Agencies regarding a matter covered under this Order, including matters involving annual appropriation requests, each affected liaison officer and the SPC will resolve the dispute to the maximum extent possible. If the dispute cannot be resolved between each affected liaison officer and the SPC, then the matter will be resolved by the affected agency heads and the commissioner of the Department of Natural Resources. If the dispute cannot be resolved by the affected agency heads and the commissioner of the Department of Natural Resources, then the matter will be resolved by the governor, after considering any recommendations of the Gas Pipelines Cabinet.

    Unless contrary to any dispute resolution process in statute or regulation, in the event of a dispute between Designated Agencies involving a matter subject to the Designated Agencies' statutory or regulatory authority, each affected liaison officer and the SPC will resolve the dispute to the maximum extent possible. If the dispute cannot be resolved by the affected liaison officer and the SPC, then the matter will be resolved by the affected agency heads. If the dispute cannot be resolved by the agency heads, then the matter may be considered by the governor, after consideration of any recommendations of the Gas Pipelines Cabinet. The decision of the head of the Designated Agency responsible for administering the statute or regulation in question is final. In all such disputes, the head of the Designated Agency responsible for administering the statute or regulation shall seek and consider the views of other affected agency heads before making a decision.

16. The Office of the Governor, Division of Governmental Coordination (DGC), shall coordinate the Alaska Coastal Management Program consistency review of activities related to Gas Pipelines as provided under AS 44.19.145 and 6 AAC 50. To the maximum extent allowed by law, the SPC and DGC shall coordinate their respective Gas Pipelines activities.

17. Consistent with AS 44.23.020, the Attorney General, as legal advisor to the State of Alaska, shall provide legal services to the SPCO Gas Pipelines Group and all Designated Agencies within the SPCO Gas Pipelines Group.

18. This Order is for administrative purposes only. It does not create any third party rights nor modify the statutory and regulatory authorities of Designated Agencies.

19. The SPC will submit to the Governor and the Gas Pipelines Cabinet periodic progress reports that summarize goals and objectives and accomplishments against those goals and objectives.

To the extent that this Administrative Order is inconsistent with Administrative Order No. 134, this Order supersedes those portions of that order. This Order revokes Administrative Order No. 70.

This Order takes effect immediately.

DATED at Juneau, Alaska, this 8th day of January, 2001.

Tony Knowles
Governor

TONY KNOWLES, GOVERNOR

STATE PIPELINE COORDINATOR'S OFFICE

☐ Department of Environmental Conservation
☐ Department of Natural Resources
☐ Department of Fish and Game

411 West 4th Avenue, Suite 2
Anchorage, Alaska 99501-2343
Phone: (907) 271-4336
(907) 271-5070
FAX: (907) 272-0690
TDD: (907) 271-2902

April 23, 2001

Letter No.: 01-018-JS
File No.: ADL 403427
DD.: N/A

Mr. John R. Ellwood
Vice President, Engineering and Operations
Foothills Pipe Lines Ltd.
Project Manager
Alaskan Northwest Natural Gas Transportation Company
3100 - 707 8th Avenue S.W.
Calgary, Alberta T2P3W8

Dear Mr. Ellwood,

On February 15, 2001, you wrote to me and other State of Alaska officials regarding the confidentiality of materials that were submitted in support of the Alaskan Northwest Natural Gas Transportation Company (ANNGTC) application for a gas pipeline right-of-way lease across state lands. On March 6, 2001, you wrote to me regarding continued processing of the ANNGTC right-of-way lease application. I would like to respond to both letters, and to address the status of ANNGTC materials generally and Northwest Alaska Transportation Company borehole records that are at the Joint Pipeline Office (JPO).

To the best of my knowledge, there is not a complete and current index of the records related to the ANNGTC pipeline right-of-way lease application. Because of the passage of time since the application and limited activity on the application files in recent years, I am not certain that all of these records are centralized. Some of the records are likely located in other State agencies' offices. In addition, over the years other parties have reviewed documents in the JPO library. I do not know if they reviewed any of the materials referenced in the 1982 letter from the Northwest Alaskan Pipeline Company to Mr. Alvin Ott.

As you may be aware, under Alaska Statute 40.25.110, all State agency records are open to inspection by the public unless specifically provided otherwise. While AS 38.05.035 provides that the Department of Natural Resources shall keep certain specific information confidential upon the request of the person supplying the information, this does not include all the information that may be submitted in conjunction with an application for a pipeline right-of-way lease.

Because the most recent ANNGTC application materials were submitted nearly 20 years ago, and because there does not appear to be a comprehensive index, it is impossible for my staff to determine what should properly be considered confidential. It is also difficult, if not impossible, for my staff to work with these materials, in their current state, as part of an active and ongoing application.

Accordingly, to promote the confidentiality of appropriate ANNGTC records, Foothills will need to provide a comprehensive index of those records. For each record Foothills will need to provide your proposed confidentiality status and the applicable provision of state or federal law under which the Department of Natural Resources may provide confidential treatment of the record. Before my office resumes processing of the ANNGTC State right-of-way application, Foothills will need to provide evidence that it is the successor to ANNGTC, and under what terms After providing satisfactory evidence, Foothills will need to identify the relevant application documents currently on file at the JPO, arrange to copy those documents, and provide them to me in an organized form, consistent with 11 AAC 80.005.

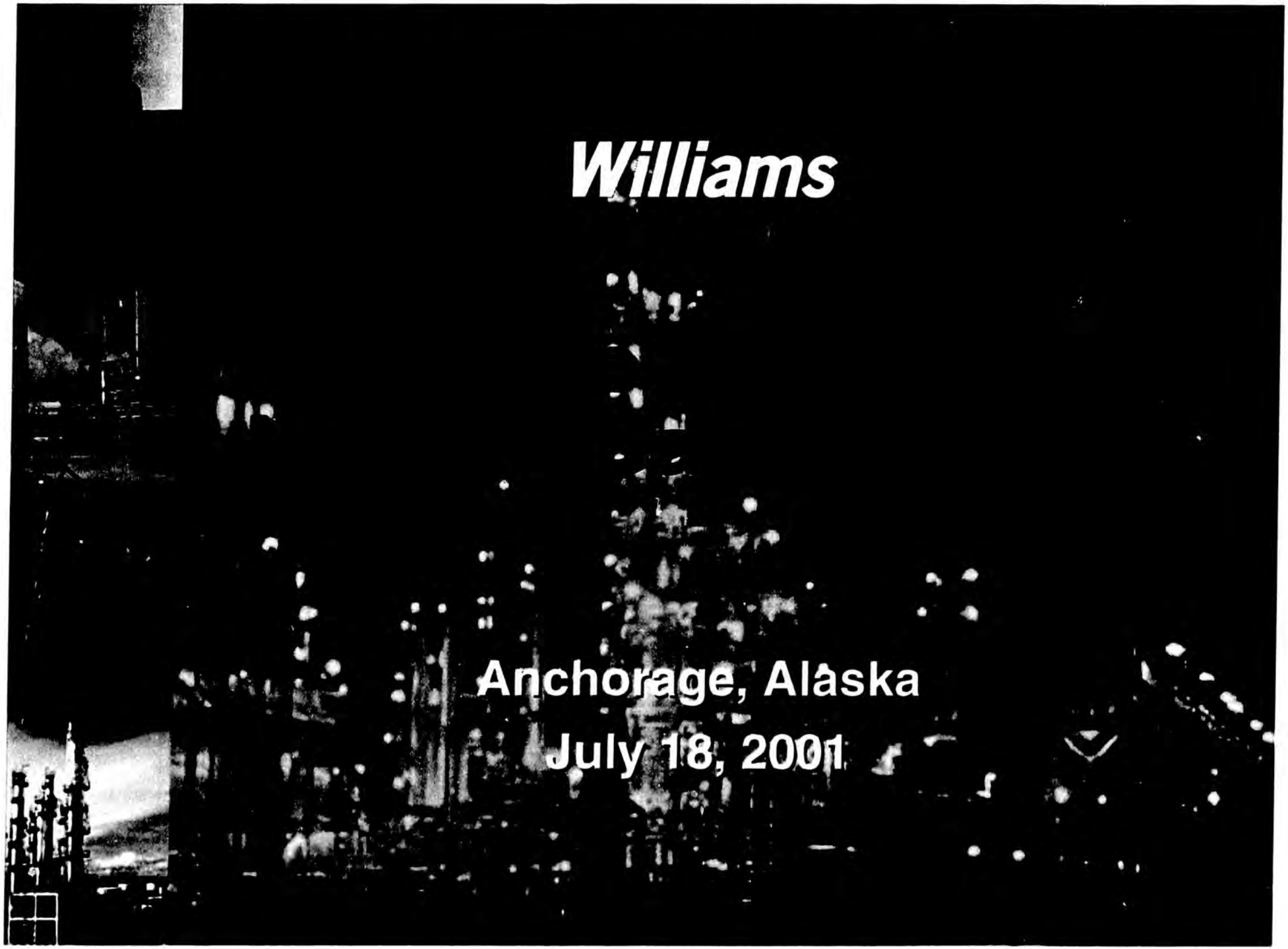
On a related matter, in the mid-1990s, the JPO obtained numerous borehole records apparently developed by or for the Northwest Alaskan Transportation Company. It appears that these were not submitted to the JPO as part of an application. Accordingly, we would like to return them to their owner. If Foothills or ANNGTC can demonstrate that they are the successor in interest to the Northwest Alaskan Transportation Company or are otherwise entitled to the records, we will return them, provided Foothills or ANNGTC indemnifies the State of Alaska and holds it harmless from and against any claims, demands, liabilities and expenses arising from or in connection with the release of these records.

I hope I have addressed the issues that you raised in your letters. Please let me know if you have any questions.

Sincerely

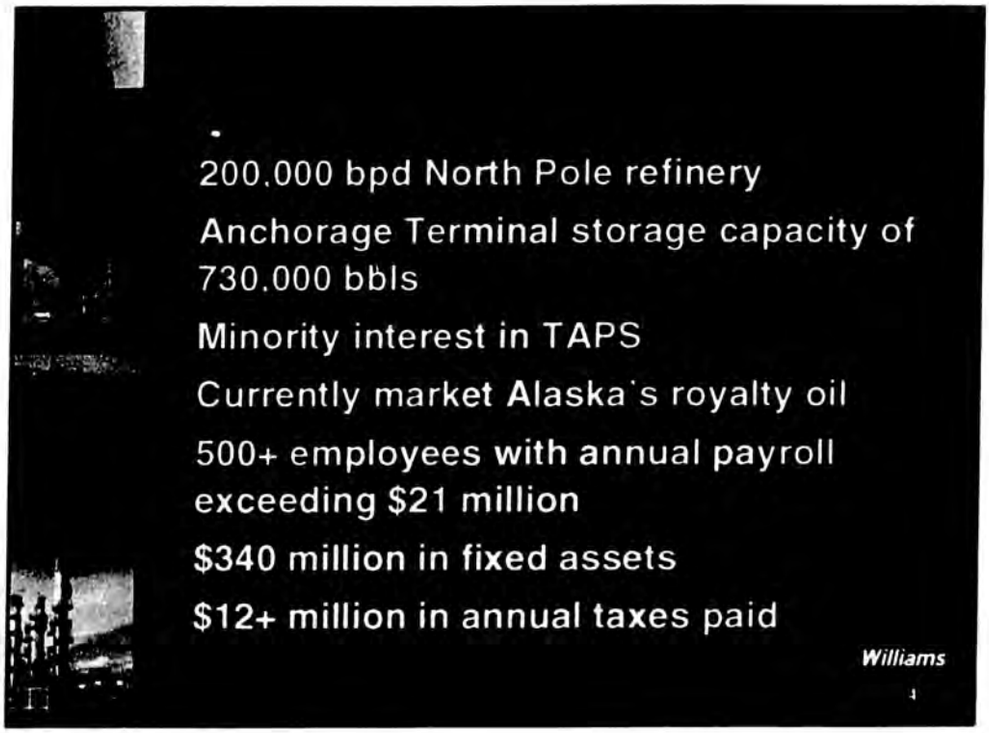
William G. Britt, Jr.
ADNR State Pipeline Coordinator

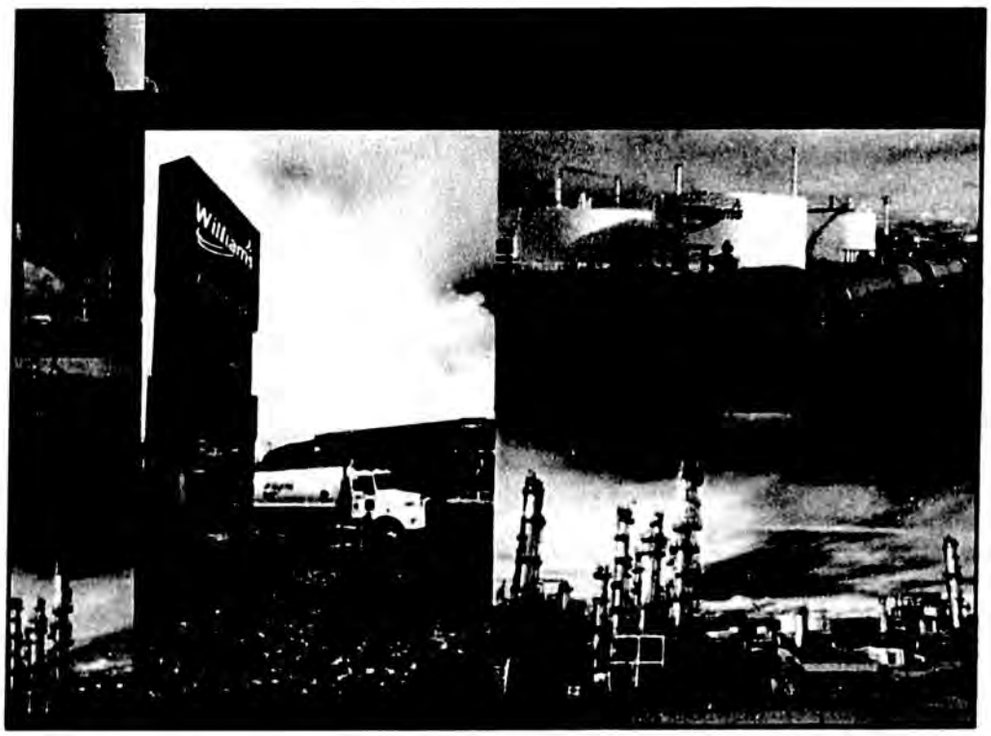
cc:
Pat Pourchot, DNR
Bruce Botelho, DOL
Michelle Brown, DEC
Wilson Condon, DOR
Ed Flanagan, DOL
Pat Galvin, DGC
Joe Perkins, DOT
Frank Rue, DFG
Jerry Brossia, BLM
Marty Rutherford, DNR
Johanna Munson, DNR
Larry Ostrovsky, DOL
Susan Anderson, DNR
Terry Klatt, Foothills Pipe Line

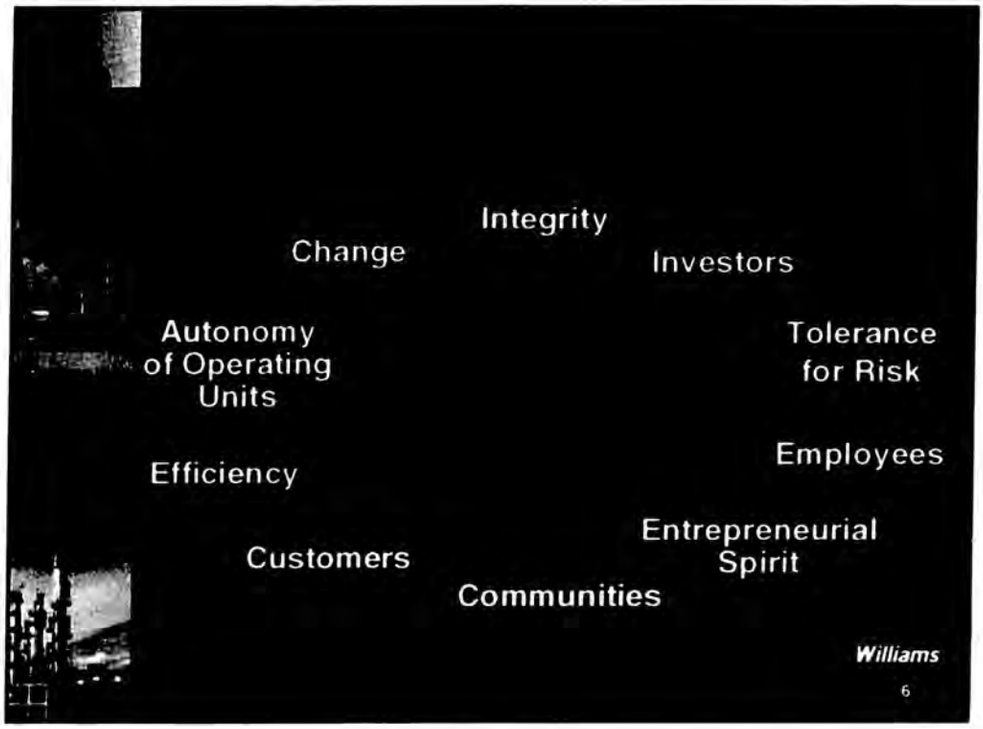

Williams
Anchorage, Alaska
July 18, 2001


One of North America's largest energy companies
Operations span energy value chain
Total assets exceeding $32 billion
$10+ billion in annual revenues
90+ years of experience
14,000 employees worldwide
Williams
2




200,000 bpd North Pole refinery
Anchorage Terminal storage capacity of 730,000 bbls
Minority interest in TAPS
Currently market Alaska's royalty oil
500+ employees with annual payroll exceeding $21 million
$340 million in fixed assets
$12+ million in annual taxes paid
Williams


Williams


Integrity
Change
Investors
Autonomy of Operating Units
Tolerance for Risk
Employees
Efficiency
Entrepreneurial Spirit
Customers
Communities
Williams
6


Arctic gas is necessary to meet North American demand growth
Opportunities within Alaska must be analyzed
The Alaska Highway Route is the best way to move North Slope gas to market
The project would benefit greatly from participation by one or more strong pipeline companies
Williams

19 Bcf/d of demand growth by 2010

- Current demand of 73 Bcf/d
- Projected to reach 92 Bcf/d by 2010

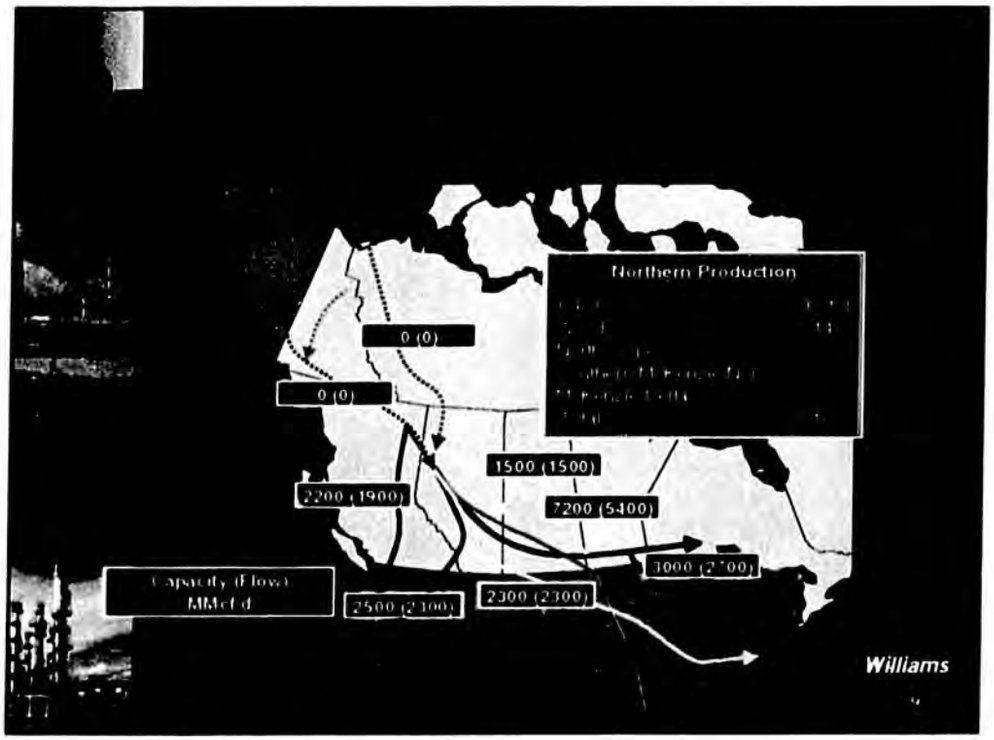
10 - 15 Bcf/d of conventional supply growth projected during same time period

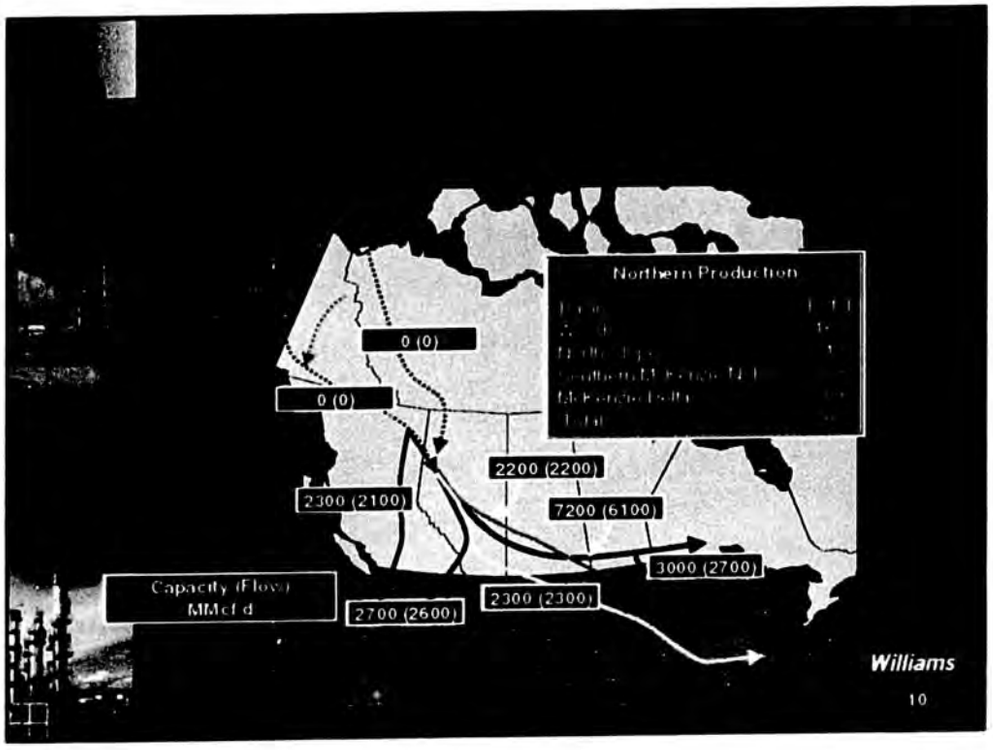
- Includes traditional L-48 and WCSB

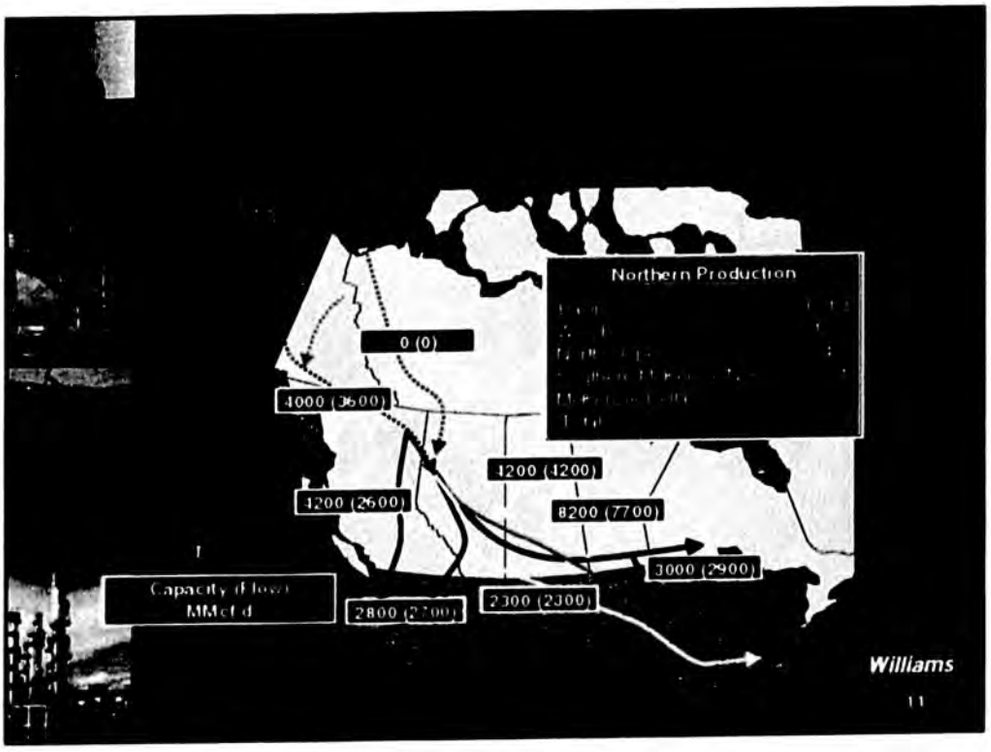
Arctic Gas is needed to fill this hole

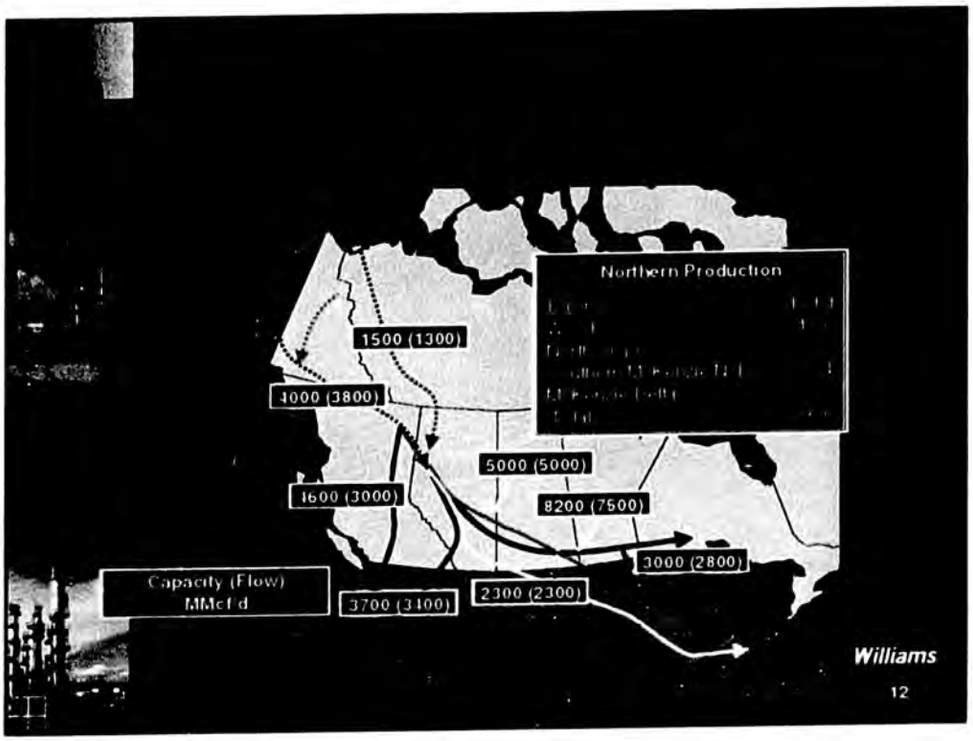
Williams

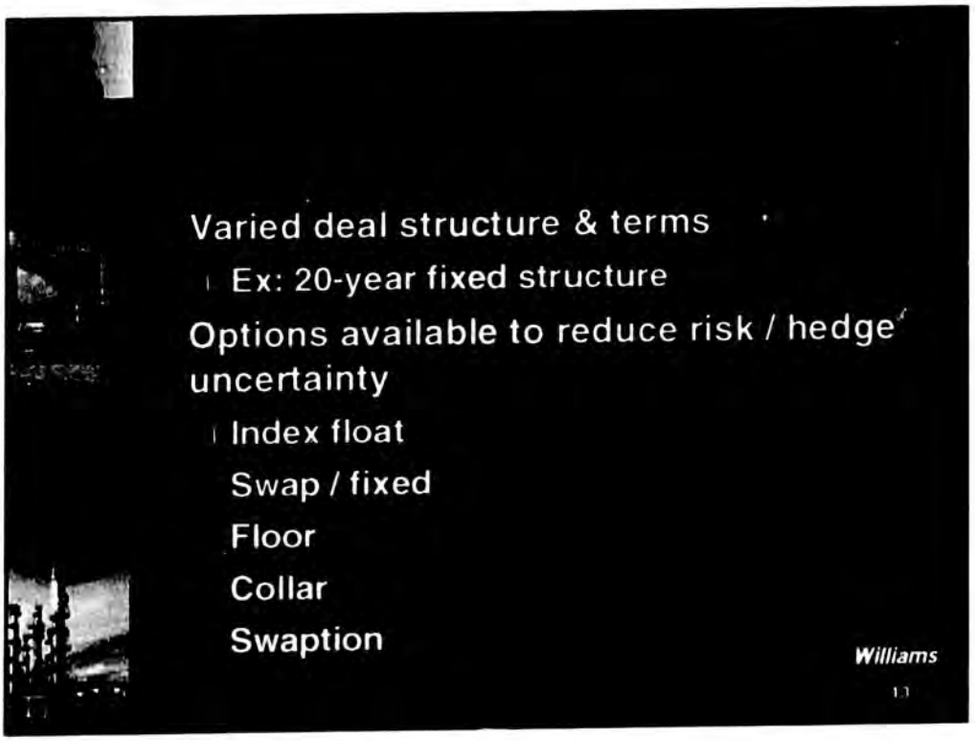
8

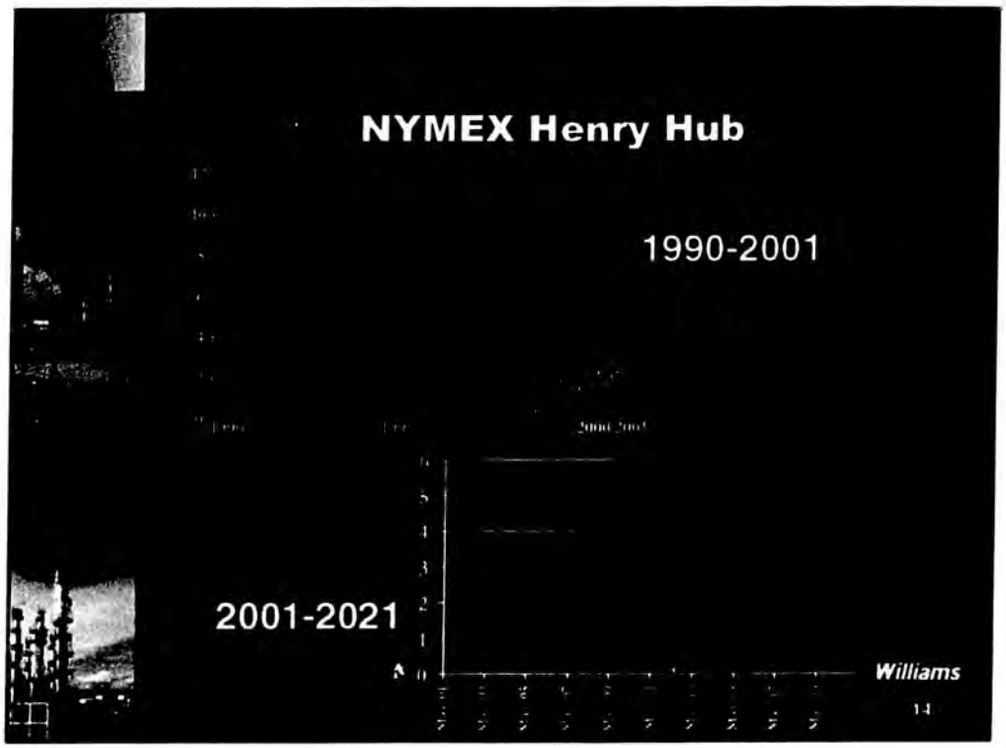


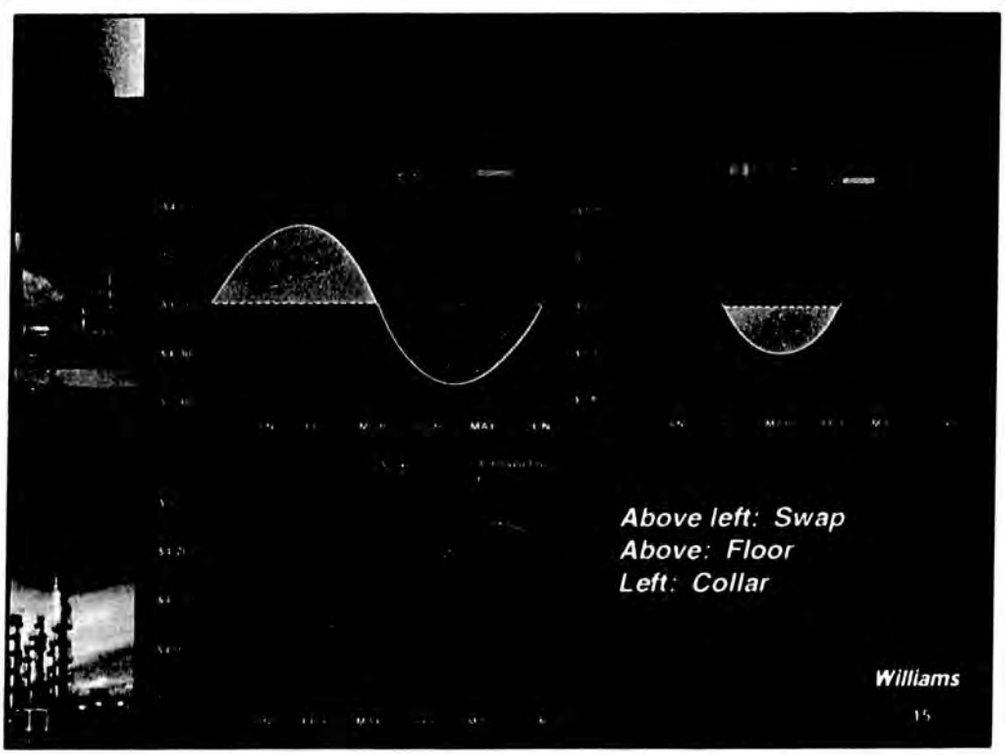

Northern Production
0 (0)
0 (0)
2200 (2200)
2300 (2100)
7200 (6100)
3000 (2700)
Capacity (Flow)
MMcf d
2700 (2600)
2300 (2300)
Williams
10


Northern Production
0 (0)
4000 (3600)
4200 (4200)
4200 (2600)
8200 (7700)
3000 (2900)
Capacity (Flow)
MMcf d
2800 (2700)
2300 (2300)
Williams
11


Northern Production
1500 (1300)
4000 (3800)
5000 (5000)
4600 (3000)
8200 (7500)
3000 (2800)
Capacity (Flow)
MMcf/d
3700 (3400)
2300 (2300)
Williams
12


Varied deal structure & terms
Ex: 20-year fixed structure
Options available to reduce risk / hedge uncertainty
Index float
Swap / fixed
Floor
Collar
Swaption
Williams
13


NYMEX Henry Hub
1990-2001
2001-2021
Williams
14


Above left: Swap
Above: Floor
Left: Collar
Williams
15

State-of-the-Art Trading Facility

81,500-square-foot trading facility

722 energy professionals

20+ PhDs; 150+ Master's degrees

Offer wide array of energy commodities, financial instruments and complex structured arrangements

$250 billion in transactions annually



Innovative. Strong. Growing.

Innovation

Introduced industry to power tolling

One of first to structure full requirements deal

Introduced first real-time energy news network EnergyNewsLive.com

Partnered with five other industry leaders in creating TradeSpark™

Strength*

Power - 141,300 GWh Top 10

Natural gas - 4.3 Bcf/d Top 15

NGLs - 281,000 bbl/d #2 in North America

Crude and refined products 728,000 bbl/d

Industry leader in earnings quality ($ 133 EBIT Bbtue)

Growth

Record 2000 net revenues of $1.6B and EBIT of $1B

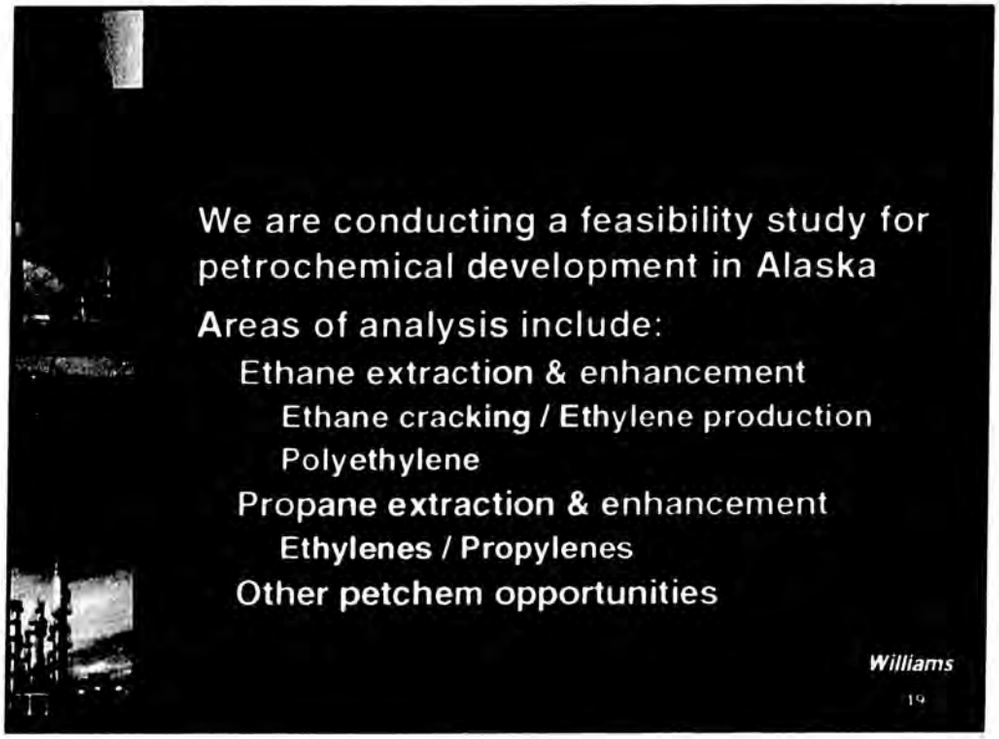
$2.2MM in net revenues per employee in 2000

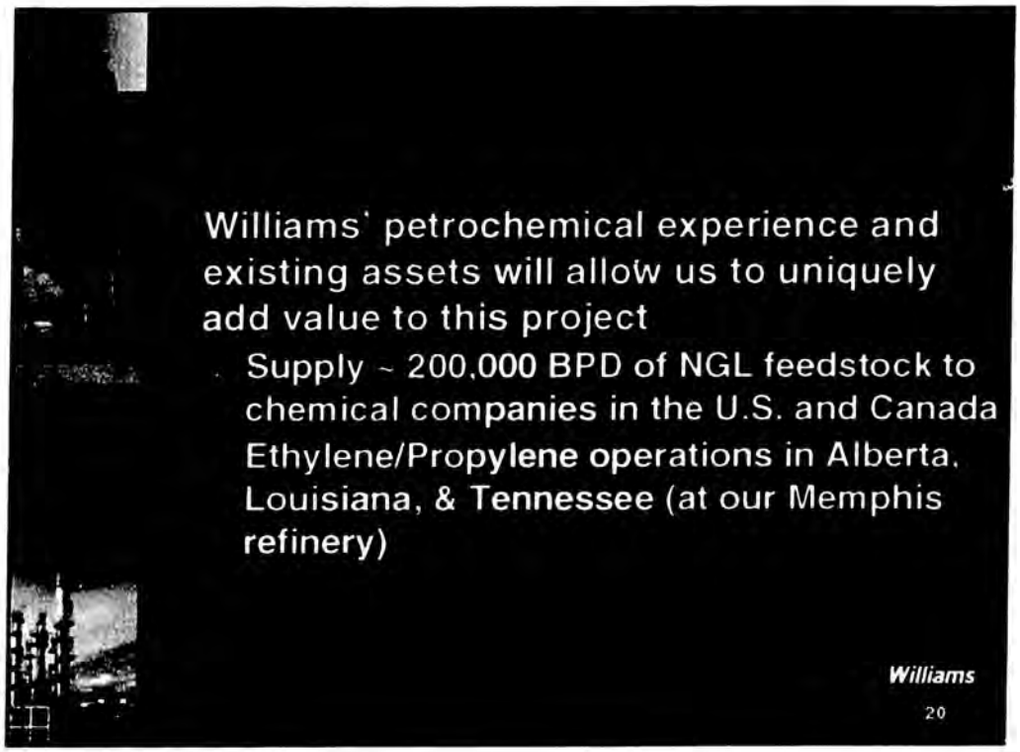
97% annual operating profit growth from 1996-2000

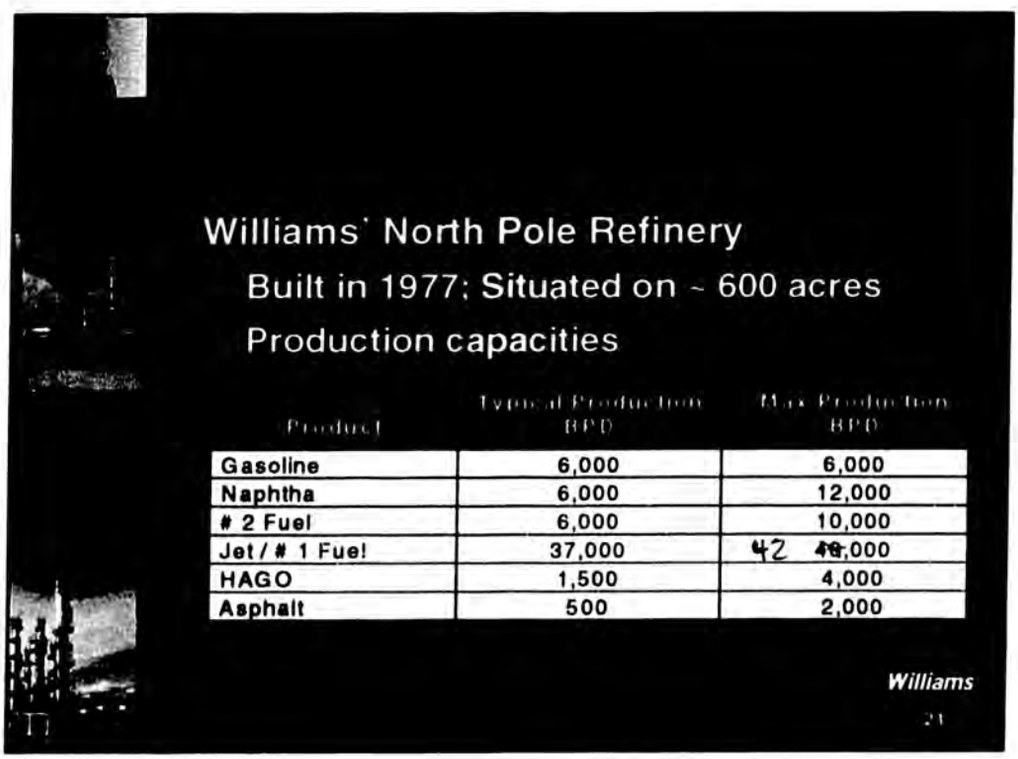
108% annual asset growth from 1996-2000

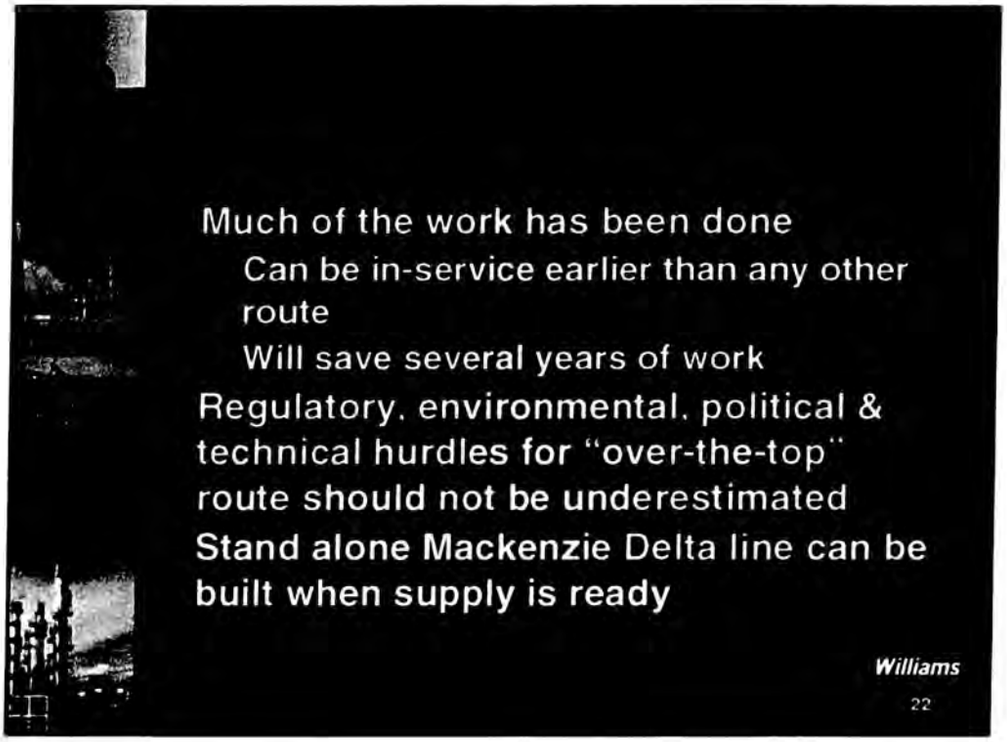
*2000 volumes and rankings


We are analyzing opportunities for in-state gas usage
Local municipality access
Commercial & industrial use
Gas-fired power generation
LNG
GTL
Williams
18

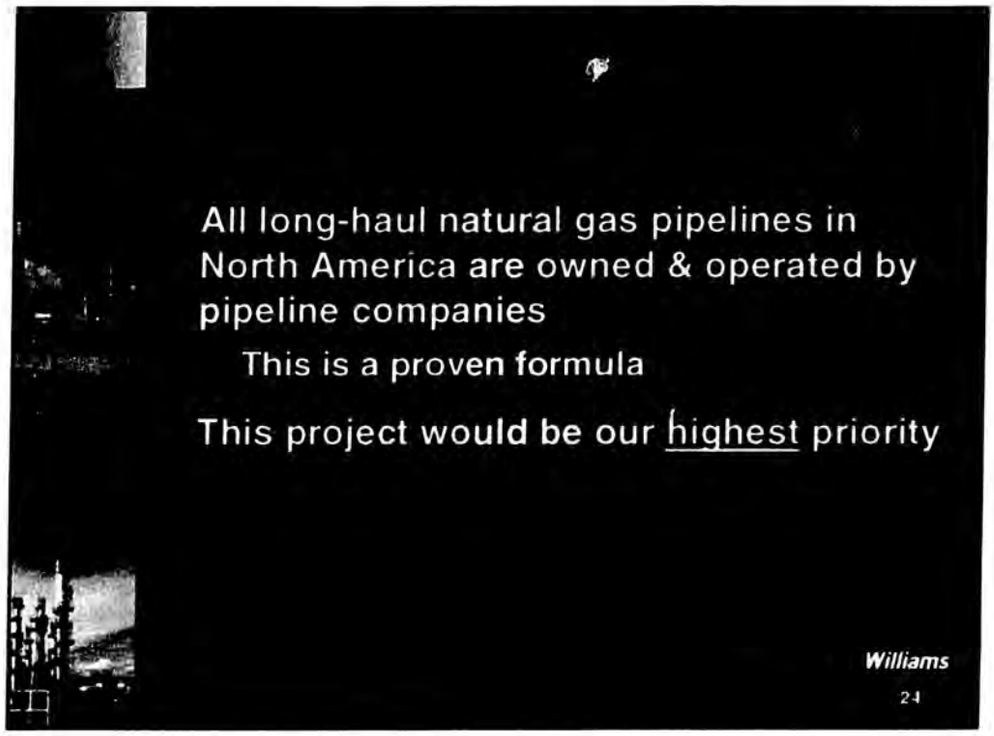

We are conducting a feasibility study for petrochemical development in Alaska
Areas of analysis include:
Ethane extraction & enhancement
Ethane cracking / Ethylene production
Polyethylene
Propane extraction & enhancement
Ethylenes / Propylenes
Other petchem opportunities
Williams
19

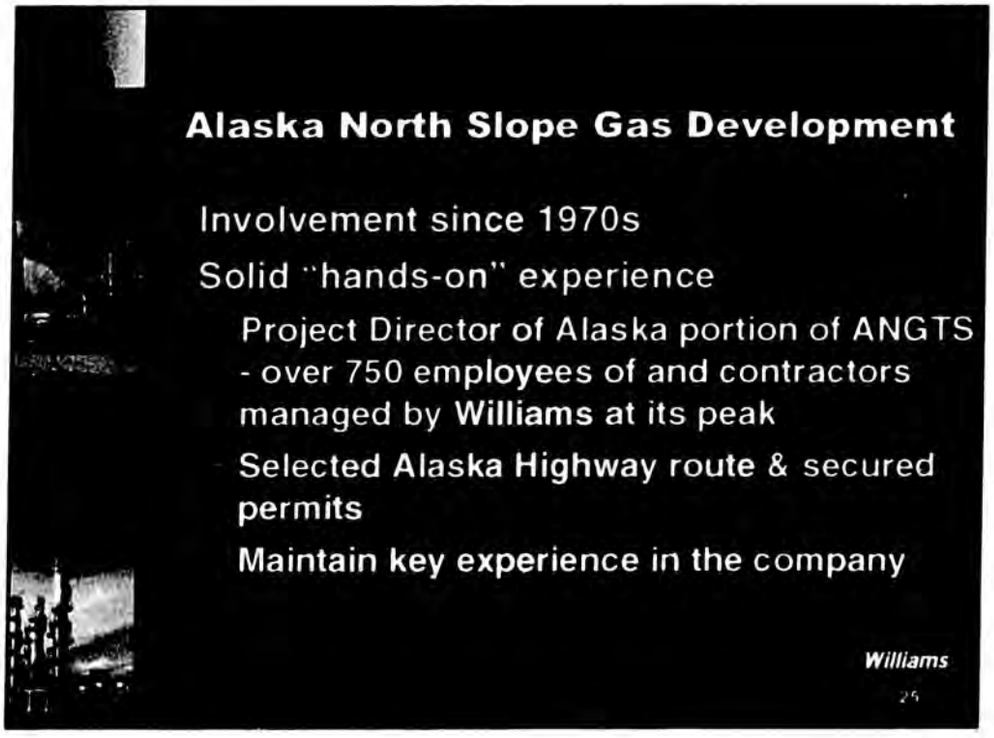

Williams' petrochemical experience and existing assets will allow us to uniquely add value to this project
Supply ~ 200,000 BPD of NGL feedstock to chemical companies in the U.S. and Canada
Ethylene/Propylene operations in Alberta, Louisiana, & Tennessee (at our Memphis refinery)
Williams
20


Williams' North Pole Refinery
Built in 1977; Situated on ~ 600 acres
Production capacities
Product
Typical Production BPD
Max Production BPD
Gasoline 6,000 6,000
Naphtha 6,000 12,000
2 Fuel 6,000 10,000
Jet / # 1 Fuel 37,000 42 48,000
HAGO 1,500 4,000
Asphalt 500 2,000
Williams
21


Much of the work has been done
Can be in-service earlier than any other route
Will save several years of work
Regulatory, environmental, political & technical hurdles for "over-the-top" route should not be underestimated
Stand alone Mackenzie Delta line can be built when supply is ready
Williams
22


Experience counts
Managing long lead-time, capital intensive gas pipeline projects
Regulatory and permitting process is extremely lengthy and complex
We manage this process daily
Healthy working relationships must be formed with key stakeholders along the pipeline right-of-way
Williams
23


All long-haul natural gas pipelines in North America are owned & operated by pipeline companies
This is a proven formula
This project would be our highest priority
Williams
24


Alaska North Slope Gas Development
Involvement since 1970s
Solid "hands-on" experience
Project Director of Alaska portion of ANGTS - over 750 employees of and contractors managed by Williams at its peak
Selected Alaska Highway route & secured permits
Maintain key experience in the company
Williams
25

Industry leader in pipeline development and construction

Front-runner in technology implementation

Unparalleled operational expertise

One of North America's largest and most strategically located natural gas and NGL infrastructures

Williams

Ongoing Projects



Williams

900-mile large diameter pipeline delivering Rockies gas to S. California

7 years from inception to in-service

- Successfully worked with numerous stakeholders to get it permitted & built

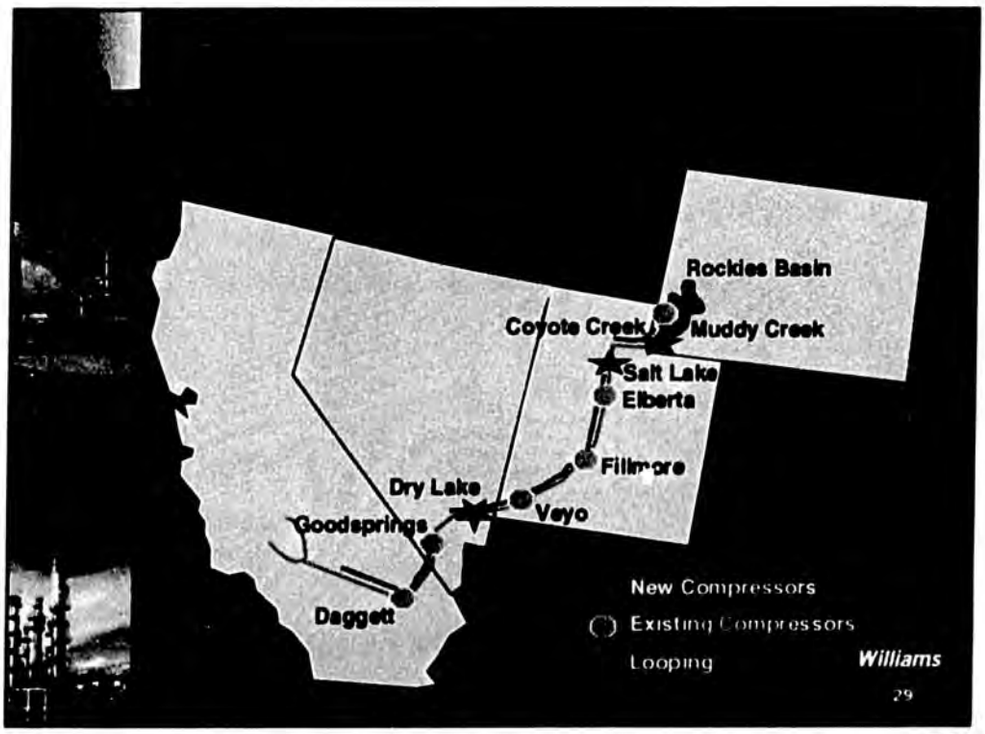
Currently transports over 700 mmcfd

- Will expand by nearly 150% by 2003

Demonstrates Williams' proven commitment and experience

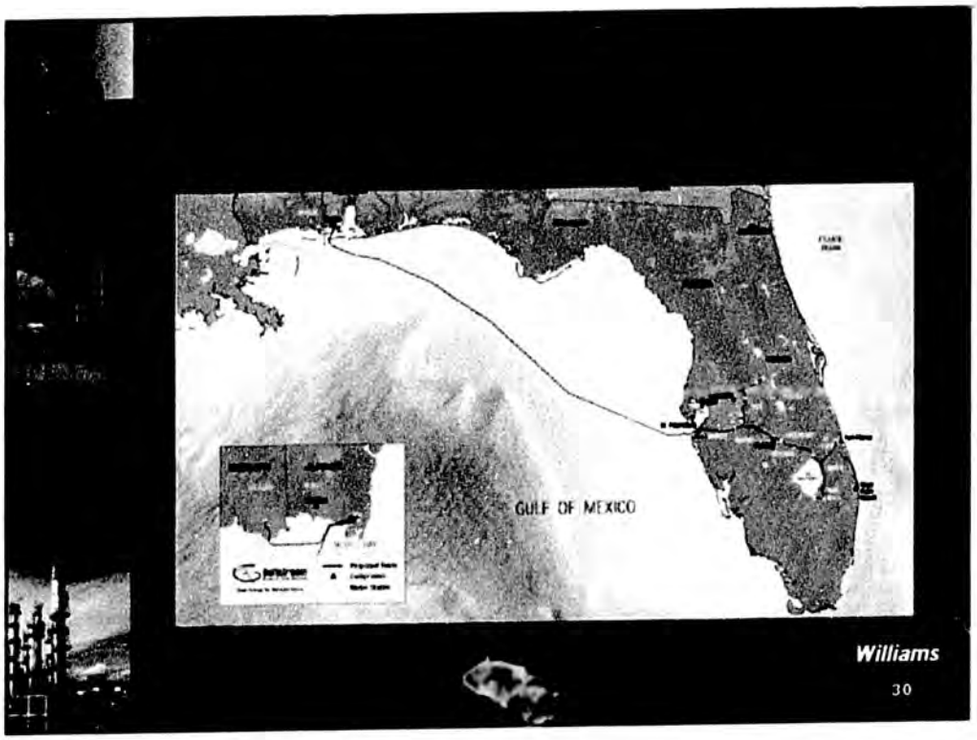
Williams

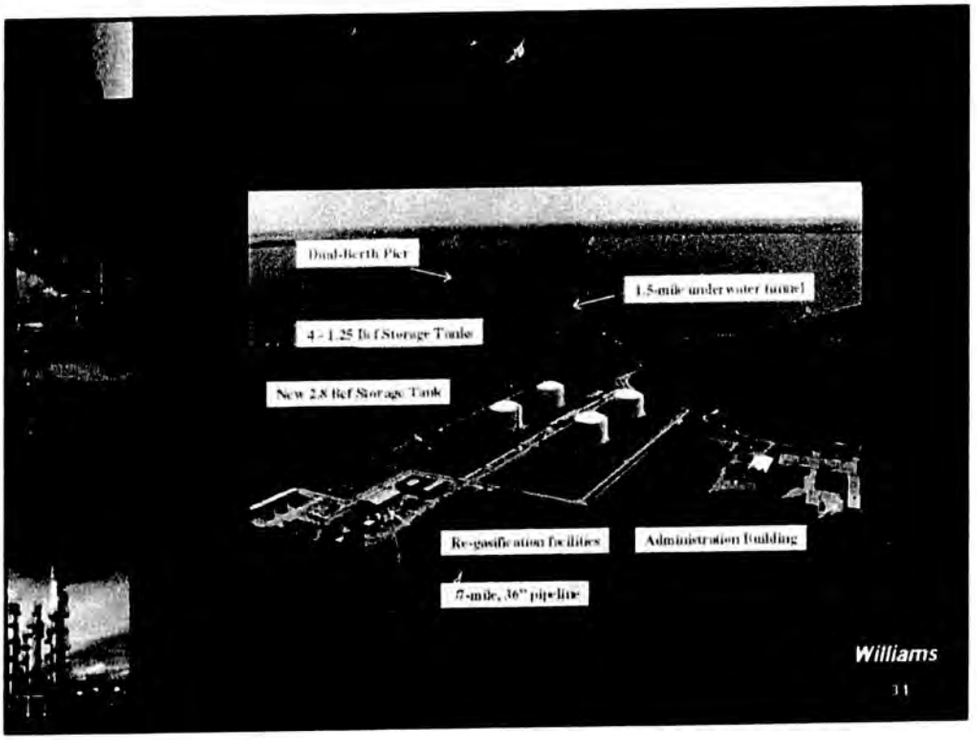
28

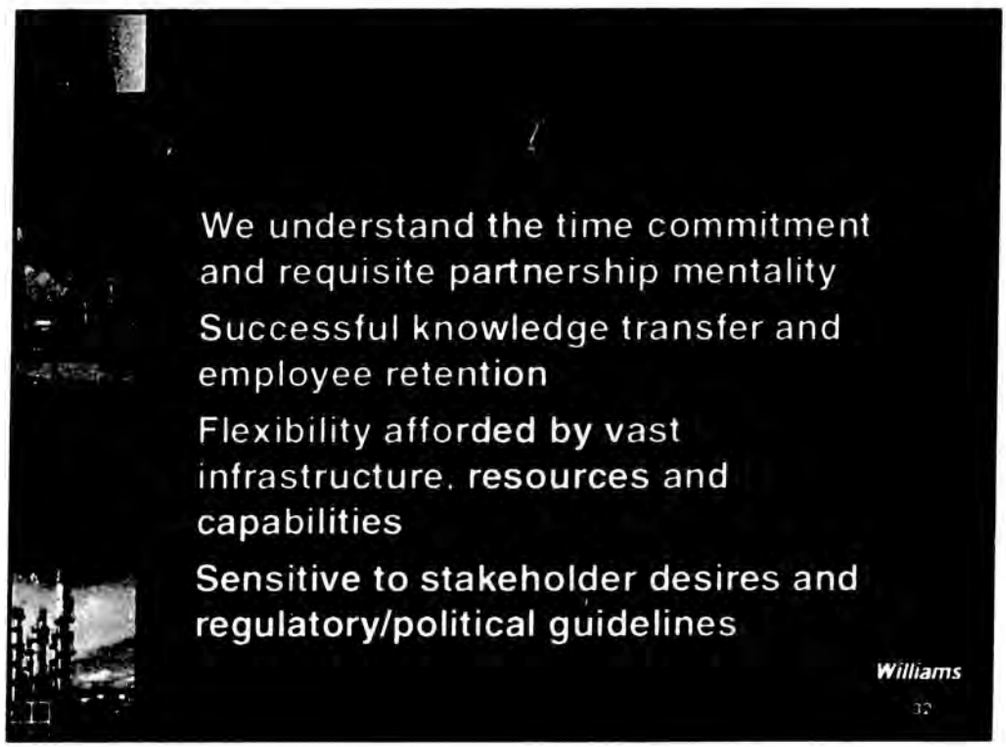


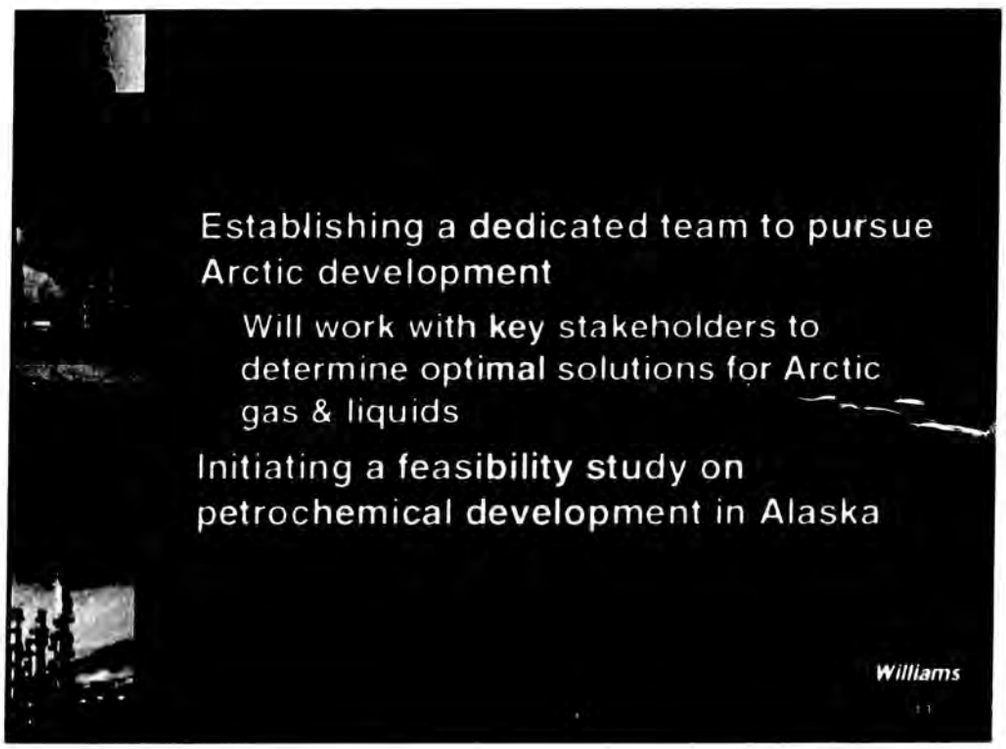
Williams

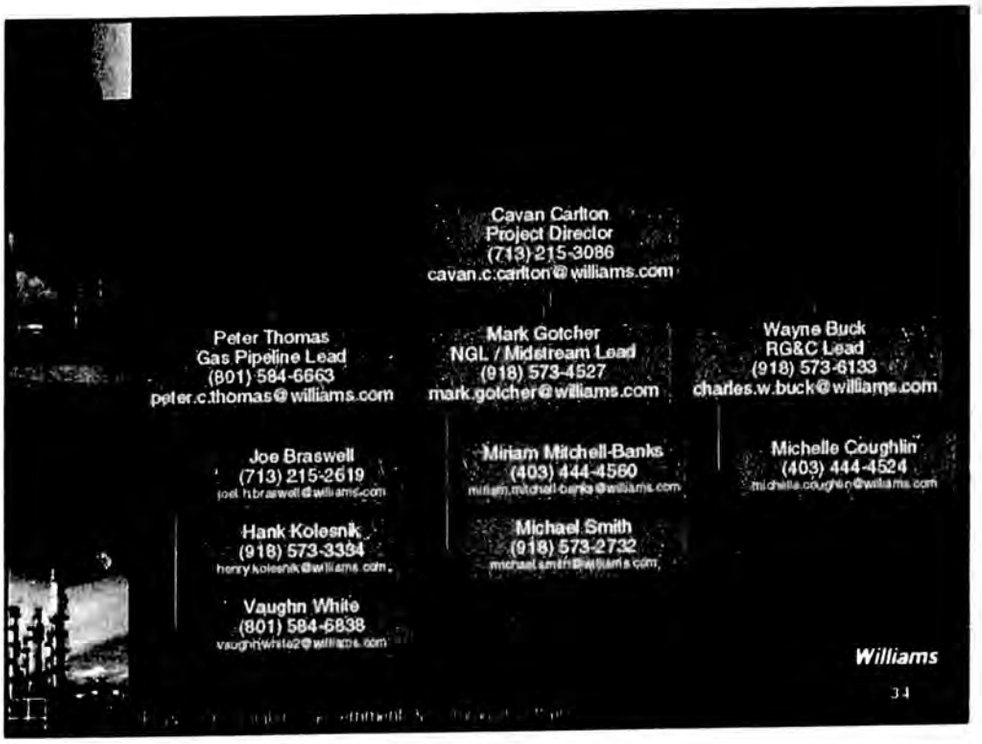
29


GULF OF MEXICO
Williams
30


Dual-Berth Pier
1.5-mile underwater tunnel
4 - 1.25 Bcf Storage Tanks
New 2.8 Bcf Storage Tank
Re-gasification facilities
Administration Building
Williams
31


We understand the time commitment and requisite partnership mentality
Successful knowledge transfer and employee retention
Flexibility afforded by vast infrastructure, resources and capabilities
Sensitive to stakeholder desires and regulatory/political guidelines
Williams


Establishing a dedicated team to pursue Arctic development
Will work with key stakeholders to determine optimal solutions for Arctic gas & liquids
Initiating a feasibility study on petrochemical development in Alaska
Williams


Cavan Carlton
Project Director
(713) 215-3086
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Peter Thomas
Gas Pipeline Lead
(801) 584-6663
peter.c.thomas@williams.com
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NGL / Midstream Lead
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mark.gotcher@williams.com
Wayne Buck
RG&C Lead
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charles.w.buck@williams.com
Joe Braswell
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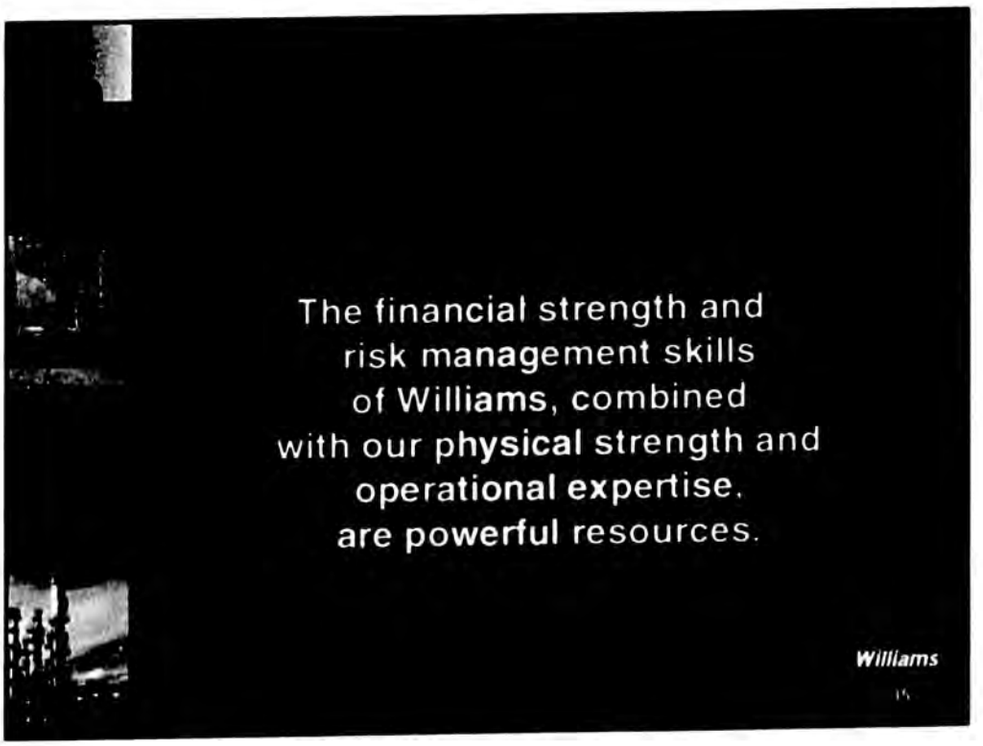
joel.h.braswell@williams.com
Miriam Mitchell-Banks
(403) 444-4560
miriam.mitchell-banks@williams.com
Michelle Coughlin
(403) 444-4524
michelle.coughlin@williams.com
Hank Kolesnik
(918) 573-3394
henry.kolesnik@williams.com
Michael Smith
(918) 573-2732
michael.smith@williams.com
Vaughn White
(801) 584-6838
vaughn.white2@williams.com
Williams
34


The financial strength and
risk management skills
of Williams, combined
with our physical strength and
operational expertise,
are powerful resources.
Williams

AGPA
ALASKA GASLINE PORT AUTHORITY

Issue 1, July 2001



On February 1, 2001, I sent Alaskan community leaders a letter and briefing paper describing the concept and mission of the Alaska Gasline Port Authority ("Port Authority"). An update of that briefing paper is attached. The Board of the Port Authority has decided it should send to the Alaskan community interested in the commercialization of Alaskan gas periodic updates on the activities of the Port Authority and news of potential interest. This is the first edition of this newsletter. Please feel free to offer suggestions regarding format and content.

Sincerely,

George Ahmaogak

Mayor, North Slope Borough
Chairman, Alaskan Gasline Port Authority

Lower Cost Energy for All Alaskans

At the last Board Meeting of the Port Authority, Chairman Ahmaogak reminded the Board that a critical part of its mission was to provide gas for the benefit of all Alaskans. He discussed the fact that a gas pipeline across Alaska might only directly benefit (in terms of access to lower cost gas) the communities along the pipeline corridor and the Anchorage/Cook inlet area that would be served by a spur line. After substantial discussion of the problem, Chairman Ahmaogak suggested that the three founding entities of the Port Authority should amend the enabling legislation of the Port Authority to direct that the 10% of the Port Authority net revenues that were to be split among the founders instead should be used to build infrastructure to deliver cheaper gas to non-pipeline corridor communities. Gas transport could be provided by LNG barges, tank trucks, or other spur lines. In some cases the funds could be used to lower the delivered cost of alternative fuels where delivery of gas is uneconomical. The Board unanimously adopted the Chairman's suggestion and passed a resolution requesting the founding communities to change the enabling ordinances. Once this is done, if a pipeline is built using the Port Authority structure, as much as $37,000,000 per year will be used to lower the energy costs for non-pipeline corridor communities. This measure will help ensure that the Port Authority achieves its goal of benefiting *all* Alaskans.



Initial Focus of the Port Authority

The initial focus of the Port Authority was to engage consultants to determine if there was a project or series of projects that could develop North Slope gas on an economic basis. A 55,000 man-hour study of construction routes and cost was prepared by Bechtel, the market investigation was performed by staff and members of the Board, and the economic modeling of the results was performed

▶ SEE INITIAL FOCUS ON PAGE 2

INITIAL FOCUS ▸ CONTINUED FROM PAGE 1



by Taylor-DeJongh. Bottom line, using very conservative assumptions, the studies demonstrated the economic viability of commercializing North Slope gas via a trans-Alaskan Gas Pipeline.

Following the completion of the studies and modeling, the next focus of the Port Authority was to meet with the three major North Slope gas producers, BP, ExxonMobil, and Phillips. The companies were briefed on the results of the studies, and the Port Authority has had a continuing series of discussions with these companies and with their joint study groups. However, the companies all have significant gas assets in other parts of the world that are competing with North Slope gas for development resources. It is clear that all of these gas assets will not be developed over the short term — 5 to 10 years. Decisions will be made based on economic, strategic, and political factors. In addition, in some parts of the world, gas concessions must be developed or the gas reserve is lost or subject to a tax. Beyond making the Port Authority structure available to these producers (which can provide significant economic benefits), there is little that the Port Authority can do to influence a producer's decision regarding whether or when to develop North Slope gas.

Current Focus of the Port Authority

There are a number of other companies that are significant operators of gas pipelines and are integrated into trading and consuming gas for their own account in power plants. Many of these companies are projecting gas shortages over the 2005-2010 timeframe. Consequently, the Port Authority believes some of these companies might have a potential interest in using North Slope gas to meet their future needs. Examples of companies that may fall into this category include Enron, Duke, El Paso, and Williams. Over the last few months, the Port Authority has met with some of these companies and has begun the process of briefing them on the potential benefits of the Port Authority structure and giving them presentations regarding the Bechtel study and the Taylor-DeJongh modeling.

In each edition of this newsletter, we will give a short profile of one of these potential players. The first Company to be profiled is El Paso.

According to its Annual Report, El Paso is the only U.S. company that is a top-tier player in every segment of the natural gas business - from production and pipelines to marketing and power generation. It has over 50 billion dollars in assets. It owns over 60,000 miles of pipelines and is the third largest producer of natural gas in the United States. El Paso is also at the

▸ SEE **CURRENT FOCUS** ON PAGE 4

Advantage of a Y-split for Pipeline

Combining a gasline to the lower 48 with a gasline to an LNG and/or GTL project will lower the cost of gas transportation down each branch of the line by approximately 33 percent.

Construction Cost:

- **A single line to carry 3 bcf per day** — **$7.0 billion**
- **A Y-line to carry 3 bcf to the Canadian border and 3 bcf to an LNG/GTL facility** — **$9.7 billion**
- **Pipeline cost for each project** — **$4.85 billion**

The Numbers Game



Every day one hears claims by different entities that a particular gas project is or is not economic. Much of this rhetoric is structured to make it very difficult for one to compare the benefits of two or three Alaskan projects, or even the benefits of an Alaska project vs. one in Indonesia or Australia.

The market, with the exception of political and trade influences[1], is identical for all projects. With the exception mentioned above, all projects must compete on the basis of delivered price, quality, and reliability of delivery. Consequently, any project analysis will have to consider, at a minimum:

- All capital costs of constructing the project
- All soft costs - fees and financing costs
- All operating costs and operating risk factors[2]
- All transportation costs to market - distance, method, etc.
- Contingency funds

Outlined below are a couple examples of some of the issues in the "Numbers Game."

1. Will the pipeline part of the project also carry liquids.

At a recent presentation by a group in Alaska, it was stated that because of the 800-mile pipeline from the North Slope, Alaskan LNG would cost over $700 per ton of capacity while LNG from Darwin, Australia, would cost $200-300 per ton. Apparently, the 550-mile pipeline (a large portion of which is under sea) to Darwin was not included in this comparison because that cost was being "allocated" to the liquids also being transported.

A number of factors need to be considered in comparing the production cost of LNC from potential projects in various parts of the world. In an Alaskan project, these costs can include the conditioning plant on the North Slope, an 800-mile pipeline, and the LNG and port facilities. If all these costs are compared to only the cost of a conditioning plant and LNG plant in Darwin, Australia, for example, the Alaska project will appear non-competitive. This comparison may be misleading, however. Propane is now being reinjected into wells on the North Slope because it is too volatile to take down the TAPs line. Modern gas pipeline designs can transport this propane in a gaseous form in a gas line and it can be extracted and sold as LPG at the end of the line.

The Taylor-DeJongh and Bechtel studies have shown the Port Authority that the value of the LPG can be used to pay for the cost of the pipeline, and if allocated in this manner, would drastically change the costs being attributed to LNG production. This discussion is relevant because some of the numbers being projected for the Darwin project do not include the 550-mile pipeline, much of which is under the ocean because those costs are being allocated to the liquids.



2. Transportation Distance for LNG

A number of projects are being proposed for supplying LNG to the West Coast of the United States and Mexico in the 2005-2006 time frame. One proposal consists of transporting 4.8 million tons of LNG from a Phillips facility to be built in Darwin, Australia. This LNG would be regasified at a facility on the Northwest coast of Mexico or California. The proposed Darwin facility will be over twice the distance from this market than Alaskan LNG, and the transportation cost might be over 80 cents per million Btus higher than Alaskan LNG.

[1] *Balance of trade issues and geopolitical security issues may cause some countries such as Taiwan and Japan to give a preference to Alaskan gas.*

[2] *There has been a lot of press lately about the civil unrest in Indonesia and the fact that a number of fields were shut down by oil companies because of the danger to their employees and facilities.*

CURRENT FOCUS ▶ CONTINUED FROM PAGE 2

forefront of the development of LNG receiving terminals in the Lower 48 and has been a leader in exploring the potential for developing LNG receiving terminals on the West coast of Mexico and the United States.

Over the last couple of months, El Paso has established an experienced team of people to investigate the potential for using North Slope gas to satisfy demands in the Lower 48, Mexico and Asia. Given their position as the largest player in LNG and pipeline gas in the United States, they may represent one of the best opportunities for an integrated LNG and pipeline commercialization of Alaskan natural gas. They are in the process of meeting with all the relevant entities in Alaska to determine the economic, political, and societal factors that will enable them to determine whether participation in the commercialization of Alaska gas fits within El Paso's long-term business strategy.

THANK YOU

The Port Authority would like to thank the following entities that have sent the Port Authority resolutions of support.

City of Barrow
City of Savooga
City of Gambell
City of Wainright
City of Kaktovik
Barrow Whaling Captains Associations
City of Anaktuvuk Pass
Ukpeagvik Inupiat Corporation
City of North Pole
City of Point Hope
Letter of support from Kake Tribal Corporation
City of Whitter
City of Alakanuk
City of Chevak
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City of Kotzebue
City of White Mountain
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City of Emmonak
City of Cordova
City of Lower Stuyahok
City of Wasilla
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F200107001

Briefing Update on the Alaska Gasline Port Authority
July 18, 2001
Charlie Cole, Esq.
Vice Chairman

Mission

The mission of the Alaska Gasline Port Authority ("Port Authority") is to enable the development of Alaska's North Slope gas to the maximum benefit of all Alaskans. Ownership of the pipeline by this type of organization will substantially lower the effective cost of transporting gas from the North Slope to market and improve the economics of such a venture to a degree necessary to make the development of the North Slope gas resources financially viable.

Evolution

Pursuant to the Port Authority Act as set forth in Alaska statutes, the formation of the Alaska Gasline Port Authority by the City of Valdez, Fairbanks North Star Borough and the North Slope Borough was ratified by the electorate on October 5, 1999 by an 80% approval rate. Even prior to the official creation of the Port Authority, the founding entities began developing the concept and Project in March 1999. The first step was to form a team which would be responsible for conceptualizing and developing a financially viable project. The project initially envisioned was a natural gas conditioning plant on Alaska's North Slope, and an 800 mile pipeline to an LNG tidewater facility at Valdez. The goal was to facilitate the maximum use of Alaska's natural gas both within Alaska and exported to other markets including the continental United States.

In March 1999 the Port Authority retained Bill Walker of Walker Walker and Associates, LLC as General Counsel and Rigdon Boykin of O'Melveny & Myers, LLP, an international law firm with substantial experience with tax exempt entities, project financing and the oil industry, as Special Project Counsel.

In September of 1999, the Port Authority entered into a Memorandum of Understanding with the Bechtel Corporation. As part of that MOU, Bechtel undertook to develop cost estimates for the conditioning plant, pipeline and LNG facilities. In addition, the Port Authority retained the services of Taylor-DeJongh and Merrill Lynch to perform the financial modeling and act as financial advisors to the Port Authority.

Project Scope

The original premise of the Port Authority was to support the construction of a project that would take natural gas from the North Slope of Alaska to Valdez, make LNG and sell it to Asia. The Port Authority decided to make a very comprehensive model which

would include conservative estimates for all aspects of the project including construction, financing and operations. The costs include development costs, permitting costs, the various financing fees, interest during construction, working capital, six months debt service reserve, insurance, etc. In a similar fashion the construction costs estimates were to be all inclusive i.e., all equipment, capital spares, construction, freight, catalysts and chemicals for initial fill, commissioning and start up costs, engineering services, escalation of 8 to 10% depending on the facility, contingency (approximately 10%), insurance, licensing fees and contractor risk, overhead and fee.

At the beginning of May, 2000 Bechtel completed its EPC study based on the above premises and Taylor-DeJongh completed modeling the results of that study. This initial base case study was very valuable for the Port Authority because it gave them a ground up "new look" construction cost estimate (based on 55,000 man hours of Bechtel time) for the gas processing facility, pipeline and LNG facility construction elements which could serve as a basis for modeling other alternatives. In addition, it gave the Port Authority a realistic and conservative financial model for looking at alternative solutions to improving the project economics.

Out of this base case and other modeling of alternatives, the Port Authority in June 2000 reached two basic conclusions: First, the economics of the project are clearly affected by the amount of liquids both in the form of NGL's separated out on the Slope and inserted into the oil pipeline and the amount of propane separated out as liquid propane gas ("LPG") in Valdez. The value of these liquids as demonstrated in the financial runs is substantial. Second, this project needs to be combined with other potential projects in order to share the huge cost of the pipeline and gas conditioning facilities.

Since June 2000, gas economics have changed substantially in the Lower 48, Mexico and Asia. Today several approaches to commercialization of Alaskan North Slope gas appear to be economically viable.

Based on the cost information developed by Bechtel, the financial modeling and the changing world market for gas and LNG, the Port Authority now believes the most economic and beneficial project to both Alaska and the producers is a two-project **Y** line with one branch going to the Lower 48 along the Alaskan highway route and the other branch going to Valdez along the Alyeska pipeline route. In addition, there would be a spur line from Glennallen to Anchorage.

The Port Authority believes that using one or both of these routes substantially reduces the potential for environmental issues which could cause significant delays and increased costs. In addition, the project realizes huge economies of scale by combining a Lower 48 project with an LNG project. The Port Authority believes the **Y** line combination project effectively reduces the pipeline cost for each project from $7.0 Billion to $4.85 Billion – a savings of $2.15 Billion in construction costs for each project or a total savings of $4.30 Billion.

The Two Project Line

The concept of the Two Project Line contains the following components:

- A Conditioning Plant on the North Slope which would have the capacity to condition sufficient gas to insert 6 billion cubic feet per day (bcfd) into a pipeline
- A 550 mile 56" diameter pipeline operating at 2220 maximum pounds per square inch from the North Slope to Delta Junction
- A 150 mile 44" diameter branch line carrying 3 bcfd to the Canadian Border along the Alcan highway (The Foothills Route)
- A fractionation plant in Calgary (or in the U.S.) to extract the liquid propane gas from the Lower 48 branch of the line
- A 256 mile 46" diameter branch line carrying 3 bcfd to Valdez
- A spur line to Anchorage from Glennallen
- A fractionation plant to extract the liquid propane gas in Valdez
- A 15 Million Ton per year LNG Plant (at full ramp up) and port facilities in Valdez

Cost Of Two Project Line

Construction Cost

Conditioning Plant (assuming no efficiencies from existing plant)	$ 4.2 Billion
Pipeline (including the two branches)	$ 9.7 Billion
LPG Fractionation Plant	450 Million
LNG Plant and Port Facilities	$ 3.65 Billion
Construction Cost Total	$18.0 Billion
(includes escalation and $1.8 Billion contingency)	

Soft costs

Interest during construction	$ 4.9 Billion
Owners contingency	900 Million
Debt service reserve	$ 1.0 Billion
Financing fees, working capital, etc.	$ 1.0 Billion
	$ 7.8 Billion
Minus pre-completion revenue	-$ 3.2 Billion
Total Financing required	$22.6 Billion

For both LNG Project and pipeline to Alaskan-Canadian border for Lower 48 sales.

The Port Authority is not claiming that this represents the best or only project that should be developed. It will make its research and numbers available to any qualified

user and hopes further optimization of the design and costs will yield better results. **But**, the financial modeling performed by the Port Authority has demonstrated that this design and cost structure (as conservative as it may be) is financially viable and should be economically attractive to the Producers, Alaskans and the State of Alaska.

It is very important to note that while the Port Authority believes that a two-project line is of the greatest economic benefit to Alaska and the producers, the Port Authority will support **any** gas pipeline route that follows the existing pipeline corridor to Fairbanks and then along the Alaskan highway to the Lower 48 or to south central Alaska for conversion to LNG or gas to liquids (GTL) or other marketable petroleum projects.

Financial Results of Two Project Line

Obviously the financial returns of any project depends on cost assumptions, interest rates and the projected sales price of gas, LNG and LPG. Outlined below are an estimate of the range of returns for the various parties involved based on the Bechtel numbers and the Taylor-DeJongh modeling using conservative historical numbers for the price of gas, LNG and LPG for the bottom of the range and a percentage of today's prices as the upper part of the range. These benefits also include the revenues from the Propane which is transported down the line in a gaseous form and extracted as a liquid at the end of the line.

Producers	$2 Billion to $3 Billion per year
State (royalties, severance tax, corporate income tax and share of $370 Million)	$750 Million to $980 Million
Payment in lieu of property taxes	$114 Million per year
All communities in Alaska divided by population with the smallest receiving a minimum of $50,000	$111 million per year
For the construction of infrastructure to deliver gas to non-pipeline corridor communities – LNG tank trucks and barges - or to lower the cost of alternate fuels	$37 million per year

Benefits of Port Authority Ownership Concept

The Port Authority believes that its ownership of the Project will result in eight primary benefits:

1. Income from the venture will be tax-exempt as a result of an IRS ruling received by the Port Authority in January, 2000. Substantial cash – Billions of Dollars- which would otherwise be used to pay income taxes in this project would be available to pay debt.

Dr. Pedro Van Meurs, energy consultant to the State of Alaska, has stated that the benefit of the tax exemption may range in the order of magnitude of $10 to $20 Billion on an undiscounted current dollar basis.

2. Financing structure:

   a. The Port Authority believes it can finance this facility with virtually 100% debt;

   b. The Port Authority will have a substantially lower hurdle rate for capital employed than a private organization would require;

   c. Some of the debt would be financed with tax-exempt bonds.

   d. The project's debt would be non-recourse to the State, the founding municipalities and the producers.

3. The Port Authority has substantial political advantages both within and outside Alaska.

4. A pipeline owned by the Port Authority would not be subject to FERC regulation.

5. Income to the state and communities - The enabling ordinances establishing the Alaska Gasline Port Authority sets forth that income of the Port Authority shall be distributed as follows:

   a) 60% to State of Alaska;

   b) 30% to all Alaska municipalities on a per capita basis. The goal of the Port Authority is that under normal operating conditions, this would produce a minimum of $148 million to be split each year among the municipalities.

   c) 10% to be retained by the Port Authority which will be used for infrastructure to provide gas to non-pipeline corridor communities or to lower the cost of alternate fuels for remote communities.

6. There will be more certainty of gas for in-state usage.

   a) The Port Authority will insure that a spur line will be built to allow the Cook Inlet / Anchorage area, etc. access to North Slope Gas.

   b) The Port Authority can use retained revenues to develop LNG transport to other communities accessible by road or water.

7. More control over price to consumer of in-state gas usage.

   For example, gas to Anchorage or Fairbanks could be in the $1.80 per mmbtu range.

   $3.00 Chicago price
   -$1.20 Tariff from Canadian Border to Chicago
   $1.80

8. No need to give up tax revenue, royalties, etc. to subsidize the project.

For more information, please contact Dave Dengel, interim executive director at 907-835-4313 or any of the Board Members below:

Member Entities – Board Members

North Slope Borough	***Fairbanks North Star Borough***	***City of Valdez***
George Ahmaogak, Sr., Mayor (Chairman) (907) 852-2611	Rhonda Boyles, Mayor (907) 459-1304	Dave Cobb (Secretary) (907) 835-4874
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AIDE MEMOIRE
MEETING WITH ALASKA GASLINE PORT AUTHORITY

March 30, 2000

Dr. Pedro van Meurs

INTRODUCTION

The consultant met on March 17 and 18 with Mr. Bill Walker of the Alaska Gasline Port Authority and their legal counsel of O'Melveny & Myers.

A document (Index Number 103.02-01) was provided to the consultant containing an opinion of the Internal Revenue Service indicating that the Authority would not be required to file federal income tax returns or pay federal income tax on its income.

It was explained to the consultant that this opinion would typically also mean that there would be no State corporate income tax as well.

The Alaska Gasline Port Authority is contemplating being the owner of the LNG project from the lease boundary on the North Slope to the loading point FOB Valdez. This means that the tax exemption would apply to the conditioning of the gas, the pipe line transportation and the liquefaction and loading of the LNG on tankers.

The Alaska Gasline Port Authority indicated that they would not be involved in the production of the gas or the shipping by LNG tankers.

The consultant was asked to provide his views on the impact on the economics of the project based on these conditions.

VIEWS OF THE CONSULTANT

An exemption from federal and state corporate income tax would have a very beneficial impact on the rate of return of the Alaska LNG project, assuming a project structure can be realized in which the exemption would indeed apply.

The consultant carried out previously analysis for the State of Alaska on an Alaska LNG project involving a capacity of 14.5 million tons, a 30 year cashflow, a CIF price in the Far East of $ 3.50 per MMBtu and 3% escalation of costs and prices. Total project investments were estimated between $ 12 and $ 15 billion.

The previous conclusion was that the project costs need to be reduced considerably in order for the project to be economically viable. Assuming costs can be reduced, fiscal restructuring would enhance the possibilities of the project.

Based on the above total project configuration, the net benefit of the tax exemptions may range in the order of magnitude of $ 10 to $ 20 billion on an undiscounted current dollar basis.

The net tax benefit on a total project basis will depend very much on how the benefit is distributed between the producers, consumers, the Alaska Gasline Port Authority and other parties. For instance, the tax benefit would be at the lower end of the above mentioned range if this benefit would be used:

- to lower the "toll" between the lease boundary and the FOB export point and to increase in the lease boundary price, or
- to lower the CIF price to consumers in Asia in order to make the introduction of a large volume of gas feasible in the near future.

The tax exemption could strengthen the economics of the project considerably, provided the Alaska Gasline Port Authority:

1. finds a way to lower the overall costs of the project,
2. is able to create with other parties a financial and organizational configuration in which the project can proceed, and
3. is able to create conditions under which this exemption can be effectively used to the benefit of the total project.



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Alaska Gasline Port Authority

AGPA Financial Model Assumptions and Results

July, 2001

TAYLOR-DEJONGH, INC.

AGPA
ALASKA GASLINE PORT AUTHORITY

Overview

- Project Cost Assumptions
- Financing Concept and Assumptions
- Financial Model Results
- Benefits of AGPA Financing and Tax-Exempt Status

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Alaska Gasline Port Authority

EPC Cost Assumptions

- Gas Conditioning Plant (GCP): $ 4.2 billion
- Pipeline: $ 9.7 billion
  - 6 Bscfd from Prudhoe Bay to Delta Junction
  - 3 Bscfd from Delta Junction to Valdez
  - 3 Bscfd from Delta Junction to Canadian border
- LNG Plant: $ 4.1 billion
  - Three trains total
  - Train 1 completed in 49 months
  - Trains 2 & 3 completed in 6-month intervals
  - LNG plant cost includes port facilities and a $ 450 million facility to extract LPGs from the the inflowing gas
- Total EPC Cost: $ 18.0 billion

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Alaska Gasline Port Authority

EPC Cost Assumptions (cont'd)

Advantage of a Y-split for pipeline:

- Combining a gasline to the Lower-48 with a gasline to an LNG and/or GTL project will lower the cost of gas transportation down each branch of the line by approximately 30%.

Construction Cost:

- a single line to carry 3 Bscfd = $7.0 billion

- a Y-line to carry 3 Bscfd to Canadian border and
  3 Bscfd to an LNG/GTL facility = $9.7 billion

- pipeline cost for each project: = $4.9 billion

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Alaska Gasline Port Authority

EPC Cost Assumptions (cont'd)

Capital Cost Analysis for LNG:

- LNG Plant ($4.1 billion, including required port facilities):	$273 / ton of LNG
- LNG Plant + Pipeline ($4.9 billion for Valdez volume):	$600 / ton of LNG
- LNG Plant + Pipeline + GCP ($2.1 billion for Valdez volume):	$740 / ton of LNG
- NPV of LPG & NGL revenue stream from gas to Valdez: (at AGPA weighted average cost of capital of 7.5%)	$6 billion
- Benefit from LPGs & NGLs per ton of LNG:	$400 / ton of LNG
- Total EPC per ton of LNG, net of liquids benefit:	**$340** / ton of LNG

Note:

The estimate of the liquids benefit is based on conservative price assumptions ($12.50/bbl for LPGs and $20/bbl for NGLs). A $2.50/bbl increase in liquids price assumption increases the liquids benefit to $473 per ton of LNG. Total EPC cost is then reduced to $267 per ton of LNG.

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Alaska Gasline Port Authority

Project Costs

EPC	$ 18.0 billion
Owner's Contingency	$ 0.9 billion
Insurance	$ 0.2 billion
Development Costs	$ 0.1 billion
Working Capital	$ 0.4 billion
Owner Costs, Line Pack	$ 0.1 billion
Interest During Construction	$ 4.9 billion
Financing and Underwriting Fees	$ 0.2 billion
Debt Service Reserve Fund	$ 1.0 billion
Total Project Cost	**$ 25.8 billion**

Note: Detailed summary sheets of assumptions and results are provided at the end of this presentation.

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Alaska Gasline Port Authority

Project Costs (cont'd)

AGPA has been very conservative in estimating project costs. Cost estimates include:

- $1.8 billion of contractor's contingency, built into the EPC cost
- 8-10% of escalation provision, built into the EPC cost
- $900 million of owner's contingency, for cost overrun risks not covered by the EPC contractor
- $1 billion of debt service reserve fund

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Alaska Gasline Port Authority

Nature and Sources of Financing

- Financing concept predicated on a zero private equity scenario
- Base Case assumes 100% senior debt financing, although there is a potential for several forms of equity-like participations in the form of subordinated debt: offtaker pre-purchase financing, subordinated payment for gas, value of permits, etc.
- In an all-debt financed scenario, the project must maintain very healthy debt service cover ratios (DSCRs)
- The model targets a Minimum DSCR of 1.70x
- Target annual distribution to State and Munis: $370 million
- The project's robust economics (DSCRs > 1.70x) generate cash above the $370 million per year for State and Munis. Such extra cash can be paid to producers to increase the netback, and/or can be distributed as benefit to other stakeholders.

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Alaska Gasline Port Authority

Nature and Sources of Financing (cont'd)

Tax-Exempt Bonds:	Lower rates, but available only to qualifying entities.
Conventional (long-term) Bonds:	Can achieve long tenors (30 years); may achieve flexible amortization profile.
Commercial Banks:	Medium-long tenor (15-18 years), with flexible amortization.
Import-Finance Program in Japan:	Medium-to-long tenor (up to 18 years), low interest rate. Tied to strategic interests of the country.

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Alaska Gasline Port Authority

Nature and Sources of Financing (cont'd)

Vendor / Supplier Financing, Offtaker Advance Purchases:	Medium- tenor subordinated financing, to provide additional "cushion" to senior lenders. Not used in Base Case.
Subordinated High-Yield bonds:	Limited capacity; higher interest rate.
Pre-Completion Cash Flow:	Generated after completion of LNG trains one and two – used against cost of building trains two and three.
Bond Escrow Income:	Interest earnings on unused portion of bond issue proceeds.

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Financing Assumptions: Capital Structure

- Total Project Cost: $ 25.8 billion
- Pre-Completion Cash Flow: $ 3.0 billion
- Bond Account Income: $ 0.2 billion

- External Financing Requirement: $ 22.6 billion

- Senior Debt: $ 21.7 billion
  - Tax-Exempt Bonds: $ 3.0 billion
  - Conventional Bonds: $ 12.0 billion
  - Commercial Banks: $ 3.8 billion
  - Import Financing: $ 3.8 billion

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Alaska Gasline Port Authority

Financing Assumptions: Interest Rates

- Base Rate Assumptions
  - 30-year Treasury Bond: 5.65%
  - 6-month LIBOR: 4.20%
- Risk Spread
  - Bond spreads depend on rating
  - Bank spreads determined on a case by case basis
  - Estimating credit spread of:

Commercial banks:	1.80% over LIBOR
Conventional bonds:	1.90% over Treasuries
JBIC:	1.00% over Treasuries
Tax-Exempt Bonds:	0.30% below Treasuries

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Alaska Gasline Port Authority

Financing Assumptions: Interest Rates (cont'd)

- Swap Margin
  - Commercial banks will typically lend at a floating rate.
  - Project can obtain a fixed rate through an interest rate swap.
  - The swap margin will compensate the swap intermediary for the assumption of risk.
  - Estimated at 1.00%.
- Buffer
  - Provides a cushion against interest rate increases.
  - Provides a cushion for variances in estimated spreads and margins.
  - Built in as 0.50%.

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Alaska Gasline Port Authority

Interest Rates: Summary

Source	Base	Spread	Swap Margin	Buffer	Interest Rate
JBIC	5.65%	1.00%	0.00%	0.50%	7.15%
Comm. Bank	4.20%	1.80%	1.00%	0.50%	7.50%
Tax-Exempt Bonds	5.65%	-0.30%	n/a	0.50%	5.85%
Taxable Bonds	5.65%	1.90%	n/a	0.50%	8.05%

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Alaska Gasline Port Authority

Financing Assumptions: Tenors and Maturities

- *JBIC:* Mortgage-style amortization; final maturity of 18 years post-completion.
- *Commercial Banks:* Mortgage-style amortization; two tranches with different final maturities – 15 years and 18 years post-completion.
- *Tax-Exempt Bonds:* Flexible amortization – begins 18 years after project completion, to reduce debt service during the term of JBIC and CB loans. Final maturity: 30-years after issue date.
- *Taxable Bonds:* Amortize mortgage-style. Final maturity: 30 years after issue date.

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Alaska Gasline Port Authority

Financing Assumptions: Other Assumptions

- Financing and Underwriting Fees
  - Commitment Fees on Loans 0.50%
  - Upfront Fees on Loans 1.00%
  - Underwriting Fees on Bonds 0.35%
- Working Capital Requirements
  - 30-day period for outstanding A/R and A/P.
  - First-year working capital requirement is capitalized and funded from debt proceeds.
- Debt Service Reserve Account
  - Sized to hold on deposit the next 6-months' debt service.
  - Initially funded from debt proceeds at the end of the construction period.

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Alaska Gasline Port Authority

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2946 SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPLINE, 2001-02

Base Case Assumptions and Results

- 8.745 Bscfd of gas to GCP inlet
- 2.015 Bscfd of CO_2-rich stream returned
- **6.730** Bscfd at **1,158** Btu/scf gas purchased

- $ 0.30 / MMBtu base price of purchased feedgas
- $ 0.45 / MMBtu additicnal subordinated payment for feedgas
- **$ 0.75** / MMBtu total purchase price for feedgas

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Alaska Gasline Port Authority

Base Case Assumptions and Results (cont'd)

- 15 MMTA LNG production
- $2.50/MMBtu LNG Price (FOB Valdez);
  - Implied $3.10 landed price in Japan, assuming $0.60 transportation charge
- $3.00/MMBtu Chicago price; $1.20/MMBtu Alaska border–Alberta–Chicago tariff

- 6.000 Bscfd at 1,129 Btu/scf gas to pipeline entrance
- 2.678 Bscfd at 1,129 Btu/scf gas to LNG plant in Valdez *
- 3.161 Bscfd at 1,129 Btu/scf gas to Canada *
- 37,000 bbl/d of NGLs extracted on North Slope
- 119,000 bbl/d of LPGs extracted at Valdez
- 141,000 bbl/d of LPGs extracted from gas to Canada
- LPG price: $12.50 / bbl NGL price: $16.50 / bbl **

** Net of fuel consumption; includes LPG content*

*** Sales price of $20.00/bbl less $3.50/bbl TAPS tariff*

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Base Case Assumptions and Results (cont'd)

Benefits to Producers:

- Sale of gas for LNG and Lower 48:

$ 811 million / yr	from gas sale at base payment of $0.30/MMBtu
$ 1,216 million / yr	from subordinated gas payment of $0.45/MMBtu
$ 2,027 million / yr	total gas sale revenues
$ 0.75 / MMBtu	total sales price of gas

- Potential for accelerating Prudhoe Bay oil production: an additional 8.7 Bscfd of gas is processed. We have not attempted to quantify the benefit of such accelerated oil production, or any reduction in oil production in the out years.
- 2 Bscfd of CO_2-rich stream returned for reinjection.
- We understand that gas composition will change over time. While we have not attempted to quantify such change at this time, our capital cost estimates include the equipment necessary to handle CO_2 over time.

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Base Case Assumptions and Results (cont'd)

Benefits to State and Municipalities of Alaska:

$ 371 million / yr	royalty and severance tax on gas sale
$ 81 million / yr	royalty and severance tax on NGLs
$ 148 million / yr	corporate income tax
$ 114 million / yr	to Munis in Payment in Lieu of Taxes (PILT)
$ 222 million / yr	to State from Project cash flow
$ 148 million / yr	to Munis from Project cash flow
$ 1,084 million / yr	total to State and Municipalities

Intellectual property of Taylor-DeJongh and
Alaska Gasline Port Authority

Base Case Assumptions and Results (cont'd)

Additional Benefits to Project Stakeholders:

$ 1,748 million / yr	total excess cash
less	
$ 1,216 million / yr	$0.45/MMBtu subordinated payment to producers to increase netback
$ 532 million / yr	available for distribution to stakeholders

- This additional benefit is cash after debt service and subordinated payment to producers, in excess of $370 million retained by State and Munis.
- An increase in sales prices of LNG and gas to Canada of $0.10/MMBtu increases the amount available for distribution to stakeholders by approximately $200 million/yr.
- A decrease in interest rates of 50 bp increases the amount available for distribution to stakeholders by approximately $120 million/yr.
- An increase in sales prices of NGLs and LPGs of $2.50/bbl increases the amount available for distribution to stakeholders by approximately $300 million/yr.
- A reduction in EPC cost of $1 billion (or 5.5%) increases the amount available for distribution to stakeholders by $120 million/yr.

Intellectual property of Taylor-DeJongh and
Alaska Gasline Port Authority

Benefits of AGPA Financing and Tax-Exempt Status

- Exemption from federal income tax frees up cash to be distributed to project participants: to increase producer netback, and/or to be distributed to other stakeholders.

- Ability to issue tax-exempt bonds lowers financing costs.

- AGPA is not constrained by a private company's typical hurdle rate on capital invested. The annual retention of $370 million for the State and Munis does not generate adequate return on equity for a private project.

Intellectual property of Taylor-DeJongh and
Alaska Gasline Port Authority

Benefits of AGPA Financing and Tax-Exempt Status

Comparison assuming that both projects retain $370 million/yr, distributing extra cash to stakeholders:

Project Scenario	AGPA	Private Project	Private Project
Debt / Equity	100 / 0	100 / 0	70 / 30
Leveraged Equity IRR	n/a	n/a	3.1%
Unlevered Project Return	-2.6%	-2.9%	-2.9%
Debt Service Coverage Ratios	2.08x minimum 2.58x average	1.55x minimum 1.86x average	1.99x minimum 2.54x average
Gas Purchase Price	$0.75/MMBtu	$0.69/MMBtu[1]	$0.75/MMBtu
Income Taxes	$0	$516 million	$767 million[2]
Cash Flow to AGPA / private dividends	$370 million	$370 million	$370 million
Cash Flow Available for Distribution to Stakeholders	$532 million	$0	$444 million

Notes: 1. The Private Project 100% debt scenario does not generate sufficient cash to achieve a $0.75/MMBtu gas pruchase price

2. Income tax payments increase over time, as interest payments decrease.

Intellectual property of Taylor-DeJongh and
Alaska Gasline Port Authority

Benefits of AGPA Financing and Tax-Exempt Status

Comparison assuming that both projects pay $0.75/MMBtu for gas, keeping all available distributable cash:

Project Scenario	AGPA	Private Project	Private Project
Debt / Equity	100 / 0	100 / 0	70 / 30
Leveraged Equity IRR	n/a	n/a	8.2%
Unlevered Project Return	12.9%	6.8%	6.8%
Debt Service Coverage Ratios	2.08x minimum 2.58x average	1.55x minimum 1.86x average	1.99x minimum 2.54x average
Gas Purchase Price	$0.75/MMBtu	$0.69/MMBtu[1]	$0.75/MMBtu
Income Taxes	$0	$516 million	$767 million[2]
Cash Flow to AGPA / private dividends	$902 million	$370 million	$814 million
Cash Flow Available for Distribution to Stakeholders	$0	$0	$0

Notes: 1. The Private Project 100% debt scenario does not generate sufficient cash to achieve a $0.75/MMBtu gas pruchase price

2. Income tax payments increase over time, as interest payments decrease.

Intellectual property of Taylor-DeJongh and
Alaska Gasline Port Authority

Summary Sheets of Key Assumptions and Results

Intellectual property of Taylor-DeJongh and
Alaska Gasline Port Authority

Summary of Key Assumptions and Results

Case: Raw ***Base Case***

Last Calculated: *15-Jul-01 11:01 PM*

Error Checks: OK

Sufficient Cash Flow: OK

Capital Structure	
Debt / Equity	100 / 0
Senior Debt	22,605
Equity	-
Total Financing	**22,605**
Senior Debt	
JBIC	3,803
Comm Bank 1	3,042
Comm Bank 2	761
Loan 4	-
Loan 5	-
Loan 6	-
Bonds	15,000
Equity	
Sub Debt	-
High-Yield Bonds	-
Share Capital	-
Sub Bond Account Income	-
Internally Generated Cash	
Bond Account Income	153
Project Cash Income	3,040

Project Costs ($ MM)	
EPC	18,000
Owner's Contingency	900
Insurance	189
Land	-
Development Costs	100
Owner Costs DC	84
Line Pack	49
Working Capital	358
Loan IDC	1,686
Bond IDC	3,189
Upfront Fee	76
Commitment Fee	71
Exposure Fee	-
Underwriting Fee	53
Sub Debt IDC	-
Sub Debt Fees	-
Debt Service Reserve	1,045
Total Project Cost	**25,799**

Timing Assumptions	
Construction Begins	1-Oct-01
Operations Begin	1-Nov-05
Fully Ramped-Up	1-Nov-06
Operating Period (years)	31.0
Operating Assumptions	
GCP Inlet	
Flowrate (MM scfd)	8,745
HHV (Btu/scf)	1,047
CO2 Returned	
Flowrate (MM scfd)	2,015
HHV (Btu/scf)	676
Gas Purchased	
Flowrate (MM scfd)	6,730
HHV (Btu/scf)	1,158
LNG Production	
Flowrate (MM scfd)	2,307
HHV (Btu/scf)	1,029
Gas to Canada (w/ liquids content)	
Flowrate (MM scfd)	3,161
HHV (Btu/scf)	1,129
Gas to Canada (liquids stripped)	
Flowrate (MM scfd)	2,954
HHV (Btu/scf)	1,022
Liquids Sold by Project (bbl/d)	
LPG	260,000
NGL	81,000
Liquids from Tolled Gas (bbl / d)	
LPG	-
NGL	-
Prices of Liquids ($ / bbl)	
LPG	12.50
NGL[6]	16.50

Cash Flow Results ($ MM)[1]	
LNG Revenue	2,058
Liquids Revenue	1,590
Canada Gas Revenue	1,758
Total Operating Revenue	**5,407**
Gas Purchase	811
Fixed O&M Expense	222
NGL Royalty and Severance	81
Total Operating Expenses	**1,114**
Income Taxes	-
Senior Debt Service	**2,090**
Average DSCR	2.58 x
Minimum DSCR	**2.08 x**
In Year	2020
Subordinated Debt Service	-
Permits Amortization	30
PILT	114
Subordinated Pmt / Tariff Rebate	1,748
Cash to AK and State	**370**

LNG Project Prices ($ / MM Btu)	
LNG Price FOB Valdez	**2.50**
Assumed Shipping Cost	0.60
Implied LNG Price CIF Japan	3.10

Feedgas Purchase Price($ / MM Btu)	
Feed Gas Base Price	0.30
Sub Payment per MM Btu	0.45
Effective Gas Purchase Price[3]	**0.75**

Gas to Canada Price ($ / MM Btu)	
Assumed Chicago Price	3.00
Tariff Alaska-Alberta-Chicago	1.20
Charge for Fuel / Fractination[5]	0.12
Gas Value at Canadian Border	**1.68**

Benefits to State ($ MM)**	
Royalty & Severance on Gas	371
Royalty & Sev. on NGLs and Oil	81
State CIT Revenues	148
Total State Tax Revenues	**600**
Project Cash to State	222
Total State Revenues	**822**
Benefits to Communities	
PILT	114
Project Cash to Munis	148
Total Muni Revenues	**262**
Total to AK State & Communities	**1,084**
Total AK State & Muni NPV @ 7.3%	8,855

Subordinated Payment Distribution	
Total Benefit Generated	**1,748**
Benefit per MMBtu[2]	0.65
Allocated to Increasing Netback	1,216
Total Available for Other Stakeholders	**532**

Benefits to Producers ($ MM)[4]	
Revenues from Base Gas Sale	811
Revenues from Sub Payment	1,216
Canada Tolling Netback	-
Valdez Tolling Netback	-
Total Producer Revenues	**2,027**

Present Value of Producer Revenues		
Producer NPV @	12.0%	**9,686**
Valuation Date		Sep-01

Project Returns		
Equity IRR (leveraged)		n/a
Equity NPV(leveraged) @	12.0%	1,689
Valuation Date		Sep-01

Notes:

1. *The numbers presented are annual figures for the fully ramped-up project.*
2. *Total benefit per MMBtu of gas into GCP less CO2 stream.*
3. *Netback and feedgas pruchase prices are calculated based on total gas flow into the GCP, including CO2 stream and gas for fuel consumption.*
4. *Producer benefits are expressed as pre-tax revenues.*
5. *Based on 2.7% pipeline fuel consumption and a $450 MM cost of fractionation plant, amortized over 15 yrs at 12% equity return.*
6. *Based on a sales price of $20/bbl and $3.50 TAPS tariff.*

Intellectual property of Taylor-DeJongh and
Alaska Gasline Port Authority

Summary of Key Assumptions and Results

Last Calculated: 16-Jul-01 12:23 AM

Error Checks: OK

Sufficient Cash Flow: OK

Case: Raw ***LNG and Gas to Canada Price Increase of $0.10 / MM Btu***

Capital Structure	
Debt / Equity	100 / 0
Senior Debt	22,458
Equity	-
Total Financing	**22,458**
Senior Debt	
JBIC	3,729
Comm Bank 1	2,983
Comm Bank 2	746
Loan 4	-
Loan 5	-
Loan 6	-
Bonds	15,000
Equity	
Sub Debt	-
High-Yield Bonds	-
Share Capital	-
Sub Bond Account Income	-
Internally Generated Cash	
Bond Account Income	154
Project Cash Income	3,189

Project Costs ($ MM)	
EPC	18,000
Owner's Contingency	900
Insurance	189
Land	-
Development Costs	100
Owner Costs DC	84
Line Pack	49
Working Capital	373
Loan IDC	1,685
Bond IDC	3,189
Upfront Fee	75
Commitment Fee	68
Exposure Fee	-
Underwriting Fee	53
Sub Debt IDC	-
Sub Debt Fees	-
Debt Service Reserve	1,037
Total Project Cost	**25,801**

Timing Assumptions	
Construction Begins	1-Oct-01
Operations Begin	1-Nov-05
Fully Ramped-Up	1-Nov-06
Operating Period (years)	31.0
Operating Assumptions	
GCP Inlet	
Flowrate (MM scfd)	8,745
HHV (Btu/scf)	1,047
CO2 Returned	
Flowrate (MM scfd)	2,015
HHV (Btu/scf)	676
Gas Purchased	
Flowrate (MM scfd)	6,730
HHV (Btu/scf)	1,158
LNG Production	
Flowrate (MM scfd)	2,307
HHV (Btu/scf)	1,029
Gas to Canada (w/ liquids content)	
Flowrate (MM scfd)	3,161
HHV (Btu/scf)	1,129
Gas to Canada (liquids stripped)	
Flowrate (MM scfd)	2,954
HHV (Btu/scf)	1,022
Liquids Sold by Project (bbl/d)	
LPG	260,000
NGL	81,000
Liquids from Tolled Gas (bbl / d)	
LPG	-
NGL	-

Prices of Liquids ($ / bbl)	
LPG	12.50
NGL[6]	16.50

Cash Flow Results ($ MM)[1]	
LNG Revenue	2,140
Liquids Revenue	1,590
Canada Gas Revenue	1,863
Total Operating Revenue	**5,594**
Gas Purchase	811
Fixed O&M Expense	222
NGL Royalty and Severance	81
Total Operating Expenses	**1,114**
Income Taxes	-
Senior Debt Service	**2,074**
Average DSCR	2.71 x
Minimum DSCR	**2.19 x**
In Year	2020
Subordinated Debt Service	-
Permits Amortization	30
PILT	114
Subordinated Pmt / Tariff Rebate	1,950
Cash to AK and State	**370**

LNG Project Prices ($ / MM Btu)	
LNG Price FOB Valdez	**2.60**
Assumed Shipping Cost	0.60
Implied LNG Price CIF Japan	3.20

Feedgas Purchase Price($ / MM Btu)	
Feed Gas Base Price	0.30
Sub Payment per MM Btu	0.45
Effective Gas Purchase Price[3]	**0.75**

Gas to Canada Price ($ / MM Btu)	
Assumed Chicago Price	3.10
Tariff Alaska-Alberta-Chicago	1.20
Charge for Fuel / Fractination[5]	0.12
Gas Value at Canadian Border	**1.78**

Benefits to State ($ MM)[4]	
Royalty & Severance on Gas	371
Royalty & Sev. on NGLs and Oil	81
State CIT Revenues	148
Total State Tax Revenues	**600**
Project Cash to State	222
Total State Revenues	**822**
Benefits to Communities	
PILT	114
Project Cash to Munis	148
Total Muni Revenues	**262**
Total to AK State & Communities	**1,084**
Total AK State & Muni NPV @ 7.3%	8,855

Subordinated Payment Distribution	
Total Benefit Generated	**1,950**
Benefit per MMBtu[2]	0.72
Allocated to Increasing Netback	1,216
Total Available for Other Stakeholders	**734**

Benefits to Producers ($ MM)[4]	
Revenues from Base Gas Sale	811
Revenues from Sub Payment	1,216
Canada Tolling Netback	-
Valdez Tolling Netback	-
Total Producer Revenues	**2,027**

Present Value of Producer Revenues		
Producer NPV @	12.0%	**9,686**
Valuation Date		Sep-01

Project Returns		
Equity IRR (leveraged)		n/a
Equity NPV(leveraged) @	12.0%	1,689
Valuation Date		Sep-01

Notes:

1. *The numbers presented are annual figures for the fully ramped-up project.*
2. *Total benefit per MMBtu of gas into GCP less CO2 stream.*
3. *Netback and feedgas pruchase prices are calculated based on total gas flow into the GCP, including CO2 stream and gas for fuel consumption.*
4. *Producer benefits are expressed as pre-tax revenues.*
5. *Based on 2.7% pipeline fuel consumption and a $450 MM cost of fractionation plant, amortized over 15 yrs at 12% equity return.*
6. *Based on a sales price of $20/bbl and $3.50 TAPS tariff.*

Intellectual property of Taylor-DeJongh and
Alaska Gasline Port Authority

Summary of Key Assumptions and Results

Last Calculated: 15-Jul-01 11:07 PM

Error Checks: OK

Sufficient Cash Flow: OK

Case: Raw ***Interest Rate Decrease of 50 bp***

Capital Structure	
Debt / Equity	100 / 0
Senior Debt	22,164
Equity	-
Total Financing	22,164
Senior Debt	
JBIC	3,582
Comm Bank 1	2,866
Comm Bank 2	716
Loan 4	-
Loan 5	-
Loan 6	-
Bonds	15,000
Equity	
Sub Debt	-
High-Yield Bonds	-
Share Capital	-
Sub Bond Account Income	-
Internally Generated Cash	
Bond Account Income	158
Project Cash Income	3,043

Project Costs ($ MM)	
EPC	18,000
Owner's Contingency	900
Insurance	189
Land	-
Development Costs	100
Owner Costs DC	84
Line Pack	49
Working Capital	358
Loan IDC	1,543
Bond IDC	2,976
Upfront Fee	72
Commitment Fee	63
Exposure Fee	-
Underwriting Fee	53
Sub Debt IDC	-
Sub Debt Fees	-
Debt Service Reserve	981
Total Project Cost	25,366

Timing Assumptions	
Construction Begins	1-Oct-01
Operations Begin	1-Nov-05
Fully Ramped-Up	1-Nov-06
Operating Period (years)	31.0
Operating Assumptions	
GCP Inlet	
Flowrate (MM scfd)	8,745
HHV (Btu/scf)	1,047
CO2 Returned	
Flowrate (MM scfd)	2,015
HHV (Btu/scf)	676
Gas Purchased	
Flowrate (MM scfd)	6,730
HHV (Btu/scf)	1,158
LNG Production	
Flowrate (MM scfd)	2,307
HHV (Btu/scf)	1,029
Gas to Canada (w/ liquids content)	
Flowrate (MM scfd)	3,161
HHV (Btu/scf)	1,129
Gas to Canada (liquids stripped)	
Flowrate (MM scfd)	2,954
HHV (Btu/scf)	1,022
Liquids Sold by Project (bbl/d)	
LPG	260,000
NGL	81,000
Liquids from Tolled Gas (bbl/d)	
LPG	-
NGL	-

Prices of Liquids ($ / bbl)	
LPG	12.50
NGL[6]	16.50

Cash Flow Results ($ MM)[1]	
LNG Revenue	2,058
Liquids Revenue	1,590
Canada Gas Revenue	1,758
Total Operating Revenue	**5,407**
Gas Purchase	811
Fixed O&M Expense	222
NGL Royalty and Severance	81
Total Operating Expenses	**1,114**
Income Taxes	-
Senior Debt Service	**1,962**
Average DSCR	2.73 x
Minimum DSCR	**2.22 x**
In Year	2020
Subordinated Debt Service	-
Permits Amortization	30
PILT	114
Subordinated Pmt / Tariff Rebate	1,872
Cash to AK and State	**370**

LNG Project Prices ($ / MM Btu)	
LNG Price FOB Valdez	**2.50**
Assumed Shipping Cost	0.60
Implied LNG Price CIF Japan	3.10

Feedgas Purchase Price($ / MM Btu)	
Feed Gas Base Price	0.30
Sub Payment per MM Btu	0.45
Effective Gas Purchase Price[3]	**0.75**

Gas to Canada Price ($ / MM Btu)	
Assumed Chicago Price	3.00
Tariff Alaska-Alberta-Chicago	1.20
Charge for Fuel / Fractination[5]	0.12
Gas Value at Canadian Border	**1.68**

Benefits to State ($ MM)**	
Royalty & Severance on Gas	371
Royalty & Sev. on NGLs and Oil	81
State CIT Revenues	148
Total State Tax Revenues	**600**
Project Cash to State	222
Total State Revenues	**822**
Benefits to Communities	
PILT	114
Project Cash to Munis	148
Total Muni Revenues	**262**
Total to AK State & Communities	**1,084**
Total AK State & Muni NPV @ 7.3%	8,855

Subordinated Payment Distribution	
Total Benefit Generated	**1,872**
Benefit per MMBtu[2]	0.69
Allocated to Increasing Netback	1,216
Total Available for Other Stakeholders	**656**

Benefits to Producers ($ MM)[4]	
Revenues from Base Gas Sale	811
Revenues from Sub Payment	1,216
Canada Tolling Netback	-
Valdez Tolling Netback	-
Total Producer Revenues	**2,027**

Present Value of Producer Revenues		
Producer NPV @	12.0%	**9,686**
Valuation Date		Sep-01

Project Returns		
Equity IRR (leveraged)		n/a
Equity NPV(leveraged) @	12.0%	1,689
Valuation Date		Sep-01

Notes:

1. *The numbers presented are annual figures for the fully ramped-up project.*
2. *Total benefit per MMBtu of gas into GCP less CO2 stream.*
3. *Netback and feedgas pruchase prices are calculated based on total gas flow into the GCP, including CO2 stream and gas for fuel consumption*
4. *Producer benefits are expressed as pre-tax revenues.*
5. *Based on 2.7% pipeline fuel consumption and a $450 MM cost of fractionation plant, amortized over 15 yrs at 12% equity return*
6. *Based on a sales price of $20/bbl and $3.50 TAPS tariff*

Intellectual property of Taylor-DeJongh and
Alaska Gasline Port Authority

Summary of Key Assumptions and Results

Case: Raw ***LPG and NGL Price Increase of $2.50 / bbl***

Last Calculated: *15-Jul-01 11:08 PM*

Error Checks: OK

Sufficient Cash Flow: OK

Capital Structure	
Debt / Equity	100 / 0
Senior Debt	22,403
Equity	-
Total Financing	**22,403**
Senior Debt	
JBIC	3,702
Comm Bank 1	2,961
Comm Bank 2	740
Loan 4	-
Loan 5	-
Loan 6	-
Bonds	15,000
Equity	
Sub Debt	-
High-Yield Bonds	-
Share Capital	-
Sub Bond Account Income	-
Internally Generated Cash	
Bond Account Income	154
Project Cash Income	3,247

Project Costs ($ MM)	
EPC	18,000
Owner's Contingency	900
Insurance	189
Land	-
Development Costs	100
Owner Costs DC	84
Line Pack	49
Working Capital	381
Loan IDC	1,685
Bond IDC	3,189
Upfront Fee	74
Commitment Fee	66
Exposure Fee	-
Underwriting Fee	53
Sub Debt IDC	-
Sub Debt Fees	-
Debt Service Reserve	1,034
Total Project Cost	**25,803**

Timing Assumptions	
Construction Begins	1-Oct-01
Operations Begin	1-Nov-05
Fully Ramped-Up	1-Nov-06
Operating Period (years)	31.0
Operating Assumptions	
GCP Inlet	
Flowrate (MM scfd)	8,745
HHV (Btu/scf)	1,047
CO2 Returned	
Flowrate (MM scfd)	2,015
HHV (Btu/scf)	676
Gas Purchased	
Flowrate (MM scfd)	6,730
HHV (Btu/scf)	1,158
LNG Production	
Flowrate (MM scfd)	2,307
HHV (Btu/scf)	1,029
Gas to Canada (w/ liquids content)	
Flowrate (MM scfd)	3,161
HHV (Btu/scf)	1,129
Gas to Canada (liquids stripped)	
Flowrate (MM scfd)	2,954
HHV (Btu/scf)	1,022
Liquids Sold by Project (bbl/d)	
LPG	260,000
NGL	81,000
Liquids from Tolled Gas (bbl / d)	
LPG	-
NGL	-

Prices of Liquids ($ / bbl)	
LPG	15.00
NGL[6]	19.00

Cash Flow Results ($ MM)[1]	
LNG Revenue	2,058
Liquids Revenue	1,886
Canada Gas Revenue	1,758
Total Operating Revenue	**5,702**
Gas Purchase	811
Fixed O&M Expense	222
NGL Royalty and Severance	93
Total Operating Expenses	**1,126**
Income Taxes	-
Senior Debt Service	**2,069**
Average DSCR	2.77 x
Minimum DSCR	**2.24 x**
In Year	2020
Subordinated Debt Service	-
Permits Amortization	30
PILT	114
Subordinated Pmt / Tariff Rebate	2,052
Cash to AK and State	**370**

LNG Project Prices ($ / MM Btu)	
LNG Price FOB Valdez	**2.50**
Assumed Shipping Cost	0.60
Implied LNG Price CIF Japan	3.10

Feedgas Purchase Price($ / MM Btu)	
Feed Gas Base Price	0.30
Sub Payment per MM Btu	0.45
Effective Gas Purchase Price[3]	**0.75**

Gas to Canada Price ($ / MM Btu)	
Assumed Chicago Price	3.00
Tariff Alaska-Alberta-Chicago	1.20
Charge for Fuel / Fractination[5]	0.12
Gas Value at Canadian Border	**1.68**

Benefits to State ($ MM)**	
Royalty & Severance on Gas	371
Royalty & Sev. on NGLs and Oil	93
State CIT Revenues	147
Total State Tax Revenues	**611**
Project Cash to State	222
Total State Revenues	**833**
Benefits to Communities	
PILT	114
Project Cash to Munis	148
Total Muni Revenues	**262**
Total to AK State & Communities	**1,095**
Total AK State & Muni NPV @ 7.3%	8,950

Subordinated Payment Distribution	
Total Benefit Generated	**2,052**
Benefit per MMBtu[2]	0.76
Allocated to Increasing Netback	1,216
Total Available for Other Stakeholders	**836**

Benefits to Producers ($ MM)[4]	
Revenues from Base Gas Sale	811
Revenues from Sub Payment	1,216
Canada Tolling Netback	-
Valdez Tolling Netback	-
Total Producer Revenues	**2,027**

Present Value of Producer Revenues		
Producer NPV @	12.0%	**9,686**
Valuation Date		Sep-01

Project Returns		
Equity IRR (leveraged)		n/a
Equity NPV(leveraged) @	12.0%	1,689
Valuation Date		Sep-01

Notes:

1. *The numbers presented are annual figures for the fully ramped-up project.*
2. *Total benefit per MMBtu of gas into GCP less CO2 stream.*
3. *Netback and feedgas pruchase prices are calculated based on total gas flow into the GCP, including CO2 stream and gas for fuel consumption*
4. *Producer benefits are expressed as pre-tax revenues.*
5. *Based on 2.7% pipeline fuel consumption and a $450 MM cost of fractionation plant, amortized over 15 yrs at 12% equity return*
6. *Based on a sales price of $20/bbl and $3.50 TAPS tariff*

Intellectual property of Taylor-DeJongh and
Alaska Gasline Port Authority

Summary of Key Assumptions and Results

Case: Raw **$1 bln EPC Cost Reduction**

Last Calculated: 16-Jul-01 9:44 AM

Error Checks: OK

Sufficient Cash Flow: OK

Capital Structure	
Debt / Equity	100 / 0
Senior Debt	21,234
Equity	-
Total Financing	**21,234**
Senior Debt	
JBIC	3,617
Comm Bank 1	2,894
Comm Bank 2	723
Loan 4	-
Loan 5	-
Loan 6	-
Bonds	14,000
Equity	
Sub Debt	-
High-Yield Bonds	-
Share Capital	-
Sub Bond Account Income	-
Internally Generated Cash	
Bond Account Income	143
Project Cash Income	3,042

Project Costs ($ MM)	
EPC	17,000
Owner's Contingency	850
Insurance	179
Land	-
Development Costs	100
Owner Costs DC	84
Line Pack	49
Working Capital	358
Loan IDC	1,674
Bond IDC	2,958
Upfront Fee	72
Commitment Fee	63
Exposure Fee	-
Underwriting Fee	49
Sub Debt IDC	-
Sub Debt Fees	-
Debt Service Reserve	984
Total Project Cost	**24,420**

Timing Assumptions	
Construction Begins	1-Oct-01
Operations Begin	1-Nov-05
Fully Ramped-Up	1-Nov-06
Operating Period (years)	31.0
Operating Assumptions	
GCP Inlet	
Flowrate (MM scfd)	8,745
HHV (Btu/scf)	1,047
CO2 Returned	
Flowrate (MM scfd)	2,015
HHV (Btu/scf)	676
Gas Purchased	
Flowrate (MM scfd)	6,730
HHV (Btu/scf)	1,158
LNG Production	
Flowrate (MM scfd)	2,307
HHV (Btu/scf)	1,029
Gas to Canada (w/ liquids content)	
Flowrate (MM scfd)	3,161
HHV (Btu/scf)	1,129
Gas to Canada (liquids stripped)	
Flowrate (MM scfd)	2,954
HHV (Btu/scf)	1,022
Liquids Sold by Project (bbl/d)	
LPG	260,000
NGL	81,000
Liquids from Tolled Gas (bbl / d)	
LPG	-
NGL	-

Prices of Liquids ($ / bbl)	
LPG	12.50
NGL[6]	16.50

Cash Flow Results ($ MM)[1]	
LNG Revenue	2,058
Liquids Revenue	1,590
Canada Gas Revenue	1,758
Total Operating Revenue	**5,407**
Gas Purchase	811
Fixed O&M Expense	222
NGL Royalty and Severance	81
Total Operating Expenses	**1,114**
Income Taxes	-
Senior Debt Service	**1,969**
Average DSCR	2.74 x
Minimum DSCR	**2.21 x**
In Year	2020
Subordinated Debt Service	-
Permits Amortization	30
PILT	114
Subordinated Pmt / Tariff Rebate	1,866
Cash to AK and State	**370**

LNG Project Prices ($ / MM Btu)	
LNG Price FOB Valdez	**2.50**
Assumed Shipping Cost	0.60
Implied LNG Price CIF Japan	3.10

Feedgas Purchase Price($ / MM Btu)	
Feed Gas Base Price	0.30
Sub Payment per MM Btu	0.45
Effective Gas Purchase Price[3]	**0.75**

Gas to Canada Price ($ / MM Btu)	
Assumed Chicago Price	3.00
Tariff Alaska-Alberta-Chicago	1.20
Charge for Fuel / Fractination[5]	0.12
Gas Value at Canadian Border	**1.68**

Benefits to State ($ MM)**	
Royalty & Severance on Gas	371
Royalty & Sev. on NGLs and Oil	81
State CIT Revenues	148
Total State Tax Revenues	**600**
Project Cash to State	222
Total State Revenues	**822**
Benefits to Communities	
PILT	114
Project Cash to Munis	148
Total Muni Revenues	**262**
Total to AK State & Communities	**1,084**
Total AK State & Muni NPV @ 7.3%	8,855

Subordinated Payment Distribution	
Total Benefit Generated	**1,866**
Benefit per MMBtu[2]	0.69
Allocated to Increasing Netback	1,216
Total Available for Other Stakeholders	**649**

Benefits to Producers ($ MM)[4]	
Revenues from Base Gas Sale	811
Revenues from Sub Payment	1,216
Canada Tolling Netback	-
Valdez Tolling Netback	-
Total Producer Revenues	**2,027**

Present Value of Producer Revenues		
Producer NPV @	12.0%	**9,686**
Valuation Date		Sep-01

Project Returns		
Equity IRR (leveraged)		n/a
Equity NPV(leveraged) @	12.0%	1,689
Valuation Date		Sep-01

Notes:

1. *The numbers presented are annual figures for the fully ramped-up project.*
2. *Total benefit per MMBtu of gas into GCP less CO2 stream.*
3. *Netback and feedgas pruchase prices are calculated based on total gas flow into the GCP, including CO2 stream and gas for fuel consumption.*
4. *Producer benefits are expressed as pre-tax revenues.*
5. *Based on 2.7% pipeline fuel consumption and a $450 MM cost of fractionation plant, amortized over 15 yrs at 12% equity return.*
6. *Based on a sales price of $20/bbl and $3.50 TAPS tariff.*

Intellectual property of Taylor-DeJongh and
Alaska Gasline Port Authority

Summary of Key Assumptions and Results

Case: Raw — **Private Project, 100:0 Debt/Equity**

Last Calculated: 17-Jul-01 12:42 PM

Error Checks: OK

Sufficient Cash Flow: OK

Capital Structure	
Debt / Equity	100 / 0
Senior Debt	23,917
Equity	-
Total Financing	23,917
Senior Debt	
JBIC	4,459
Comm Bank 1	3,567
Comm Bank 2	892
Loan 4	-
Loan 5	-
Loan 6	-
Bonds	15,000
Equity	
Sub Debt	-
High-Yield Bonds	-
Share Capital	-
Sub Bond Account Income	-
Internally Generated Cash	
Bond Account Income	161
Project Cash Income	2,281

Project Costs ($ MM)	
EPC	18,000
Owner's Contingency	900
Insurance	189
Land	-
Development Costs	100
Owner Costs DC	84
Line Pack	49
Working Capital	358
Loan IDC	1,494
Bond IDC	3,787
Upfront Fee	89
Commitment Fee	118
Exposure Fee	-
Underwriting Fee	53
Sub Debt IDC	-
Sub Debt Fees	-
Debt Service Reserve	1,140
Total Project Cost	**26,360**

Timing Assumptions	
Construction Begins	1-Oct-01
Operations Begin	1-Nov-05
Fully Ramped-Up	1-Nov-06
Operating Period (years)	31.0
Operating Assumptions	
GCP Inlet	
Flowrate (MM scfd)	8,745
HHV (Btu/scf)	1,047
CO2 Returned	
Flowrate (MM scfd)	2,015
HHV (Btu/scf)	676
Gas Purchased	
Flowrate (MM scfd)	6,730
HHV (Btu/scf)	1,158
LNG Production	
Flowrate (MM scfd)	2,307
HHV (Btu/scf)	1,029
Gas to Canada (w/ liquids content)	
Flowrate (MM scfd)	3,161
HHV (Btu/scf)	1,129
Gas to Canada (liquids stripped)	
Flowrate (MM scfd)	2,954
HHV (Btu/scf)	1,022
Liquids Sold by Project (bbl/d)	
LPG	260,000
NGL	81,000
Liquids from Tolled Gas (bbl/d)	
LPG	-
NGL	-
Prices of Liquids ($ / bbl)	
LPG	12.50
NGL[6]	16.50

Cash Flow Results ($ MM)[1]	
LNG Revenue	2,058
Liquids Revenue	1,590
Canada Gas Revenue	1,758
Total Operating Revenue	5,407
Gas Purchase	811
Fixed O&M Expense	222
NGL Royalty and Severance	81
Total Operating Expenses	1,114
Income Taxes	516
Senior Debt Service	2,280
Average DSCR	1.86 x
Minimum DSCR	1.55 x
In Year	2020
Subordinated Debt Service	-
Permits Amortization	30
PILT	114
Subordinated Pmt / Tariff Rebate	1,047
Cash to AK and State	370

LNG Project Prices ($ / MM Btu)	
LNG Price FOB Valdez	2.50
Assumed Shipping Cost	0.60
Implied LNG Price CIF Japan	3.10

Feedgas Purchase Price($ / MM Btu)	
Feed Gas Base Price	0.30
Sub Payment per MM Btu	0.39
Effective Gas Purchase Price[3]	0.69

Gas to Canada Price ($ / MM Btu)	
Assumed Chicago Price	3.00
Tariff Alaska-Alberta-Chicago	1.20
Charge for Fuel / Fractination[5]	0.12
Gas Value at Canadian Border	1.68

Benefits to State ($ MM)**		
Royalty & Severance on Gas		346
Royalty & Sev. on NGLs and Oil		81
State CIT Revenues		253
Total State Tax Revenues		679
Project Cash to State		222
Total State Revenues		901
Benefits to Communities		
PILT		114
Project Cash to Munis		148
Total Muni Revenues		262
Total to AK State & Communities		1,163
Total AK State & Muni NPV @	7.3%	9,960

Subordinated Payment Distribution	
Total Benefit Generated	1,047
Benefit per MMBtu[2]	0.39
Allocated to Increasing Netback	1,047
Total Available for Other Stakeholders	0

Benefits to Producers ($ MM)[4]	
Revenues from Base Gas Sale	811
Revenues from Sub Payment	1,047
Canada Tolling Netback	-
Valdez Tolling Netback	-
Total Producer Revenues	1,858

Present Value of Producer Revenues		
Producer NPV @	12.0%	8,469
Valuation Date		Sep-01

Project Returns		
Equity IRR (leveraged)		n/a
Equity NPV(leveraged) @	12.0%	1,689
Valuation Date		Sep-01

Notes:

1. *The numbers presented are annual figures for the fully ramped up project.*
2. *Total benefit per MMBtu of gas into GCP less CO2 stream.*
3. *Netback and feedgas pruchase prices are calculated based on total gas flow into the GCP, including CO2 stream and gas for fuel consumption*
4. *Producer benefits are expressed as pre-tax revenues.*
5. *Based on 2.7% pipeline fuel consumption and a $450 MM cost of fractionation plant, amortized over 15 yrs at 12% equity return*
6. *Based on a sales price of $20/bbl and $3.50 TAPS tariff*

Intellectual property of Taylor-DeJongh and
Alaska Gasline Port Authority

Summary of Key Assumptions and Results

Case: Raw — **Private Project, 70:30 Debt/Equity**

Last Calculated: 15-Jul-01 11:11 PM

Error Checks: OK

Sufficient Cash Flow: OK

Capital Structure	
Debt / Equity	70 / 30
Senior Debt	15,321
Equity	6,566
Total Financing	21,887
Senior Debt	
JBIC	161
Comm Bank 1	128
Comm Bank 2	32
Loan 4	-
Loan 5	-
Loan 6	-
Bonds	15,000
Equity	
Sub Debt	-
High-Yield Bonds	-
Share Capital	6,566
Sub Bond Account Income	-
Internally Generated Cash	
Bond Account Income	469
Project Cash Income	2,270

Project Costs ($ MM)	
EPC	18,000
Owner's Contingency	900
Insurance	189
Land	-
Development Costs	100
Owner Costs DC	84
Line Pack	49
Working Capital	358
Loan IDC	12
Bond IDC	4,176
Upfront Fee	3
Commitment Fee	7
Exposure Fee	-
Underwriting Fee	53
Sub Debt IDC	-
Sub Debt Fees	-
Debt Service Reserve	695
Total Project Cost	**24,626**

Timing Assumptions	
Construction Begins	1-Oct-01
Operations Begin	1-Nov-05
Fully Ramped-Up	1-Nov-06
Operating Period (years)	31.0
Operating Assumptions	
GCP Inlet	
Flowrate (MM scfd)	8,745
HHV (Btu/scf)	1,047
CO2 Returned	
Flowrate (MM scfd)	2,015
HHV (Btu/scf)	676
Gas Purchased	
Flowrate (MM scfd)	6,730
HHV (Btu/scf)	1,158
LNG Production	
Flowrate (MM scfd)	2,307
HHV (Btu/scf)	1,029
Gas to Canada (w/ liquids content)	
Flowrate (MM scfd)	3,161
HHV (Btu/scf)	1,129
Gas to Canada (liquids stripped)	
Flowrate (MM scfd)	2,954
HHV (Btu/scf)	1,022
Liquids Sold by Project (bbl/d)	
LPG	260,000
NGL	81,000
Liquids from Tolled Gas (bbl / d)	
LPG	-
NGL	-
Prices of Liquids ($ / bbl)	
LPG	12.50
NGL[6]	16.50

Cash Flow Results ($ MM)[1]	
LNG Revenue	2,058
Liquids Revenue	1,590
Canada Gas Revenue	1,758
Total Operating Revenue	**5,407**
Gas Purchase	811
Fixed O&M Expense	222
NGL Royalty and Severance	81
Total Operating Expenses	**1,114**
Income Taxes	767
Senior Debt Service	**1,390**
Average DSCR	2.54 x
Minimum DSCR	**1.99 x**
In Year	2030
Subordinated Debt Service	-
Permits Amortization	30
PILT	114
Subordinated Pmt / Tariff Rebate	1,660
Cash to AK and State	**370**

LNG Project Prices ($ / MM Btu)	
LNG Price FOB Valdez	**2.50**
Assumed Shipping Cost	0.60
Implied LNG Price CIF Japan	3.10

Feedgas Purchase Price($ / MM Btu)	
Feed Gas Base Price	0.30
Sub Payment per MM Btu	0.45
Effective Gas Purchase Price[3]	**0.75**

Gas to Canada Price ($ / MM Btu)	
Assumed Chicago Price	3.00
Tariff Alaska-Alberta-Chicago	1.20
Charge for Fuel / Fractination[5]	0.12
Gas Value at Canadian Border	**1.68**

Benefits to State ($ MM)**	
Royalty & Severance on Gas	371
Royalty & Sev. on NGLs and Oil	81
State CIT Revenues	324
Total State Tax Revenues	**775**
Project Cash to State	222
Total State Revenues	**997**
Benefits to Communities	
PILT	114
Project Cash to Munis	148
Total Muni Revenues	**262**
Total to AK State & Communities	**1,259**
Total AK State & Muni NPV @ 7.3%	10,608

Subordinated Payment Distribution	
Total Benefit Generated	**1,660**
Benefit per MMBtu[2]	0.61
Allocated to Increasing Netback	1,216
Total Available for Other Stakeholders	**444**

Benefits to Producers ($ MM)[4]	
Revenues from Base Gas Sale	811
Revenues from Sub Payment	1,216
Canada Tolling Netback	-
Valdez Tolling Netback	-
Total Producer Revenues	**2,027**

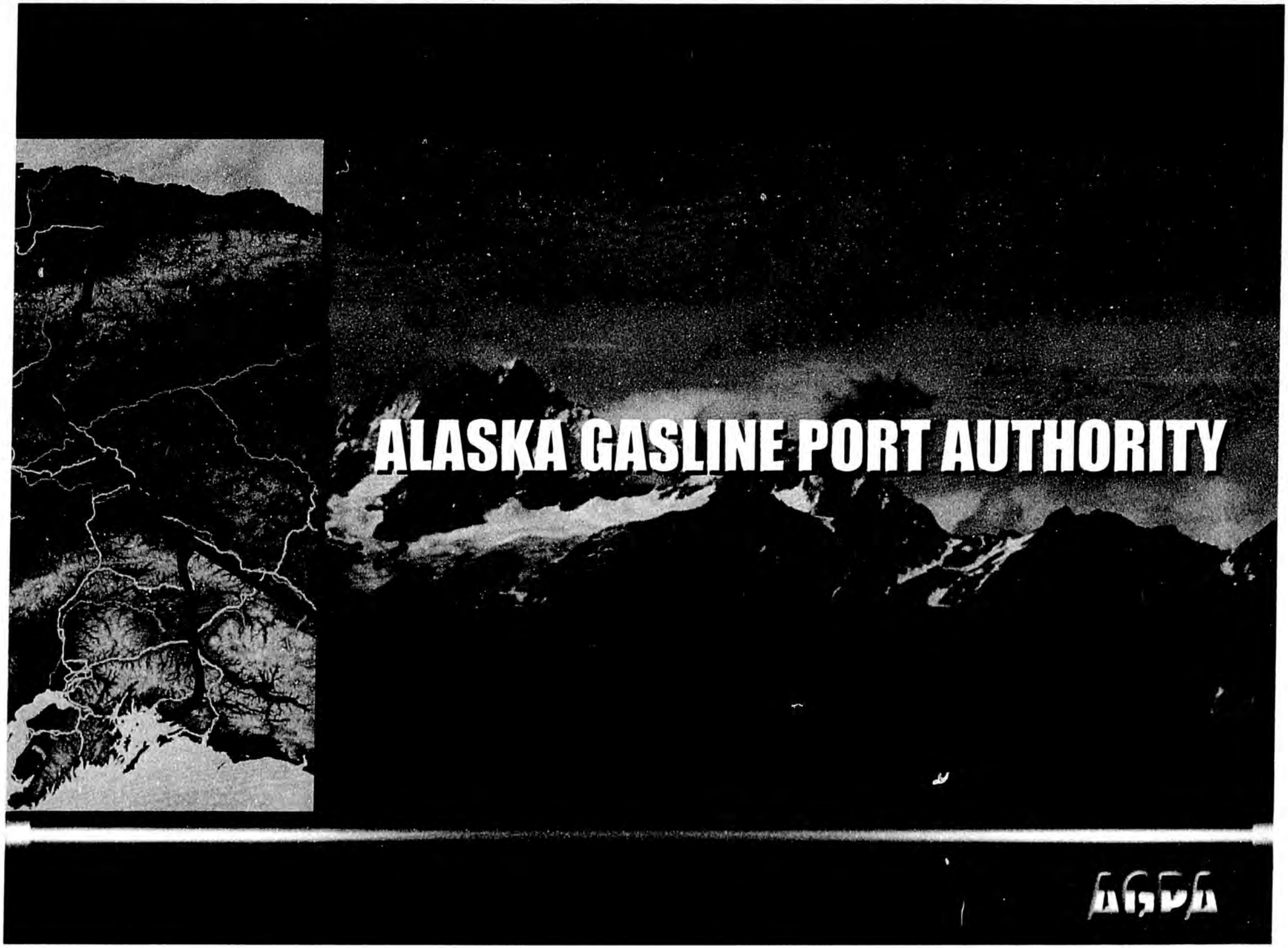
Present Value of Producer Revenues		
Producer NPV @	12.0%	**9,620**
Valuation Date		Sep-01

Project Returns		
Equity IRR (leveraged)		3.1%
Equity NPV(leveraged) @	12.0%	(3,346)
Valuation Date		Sep-01

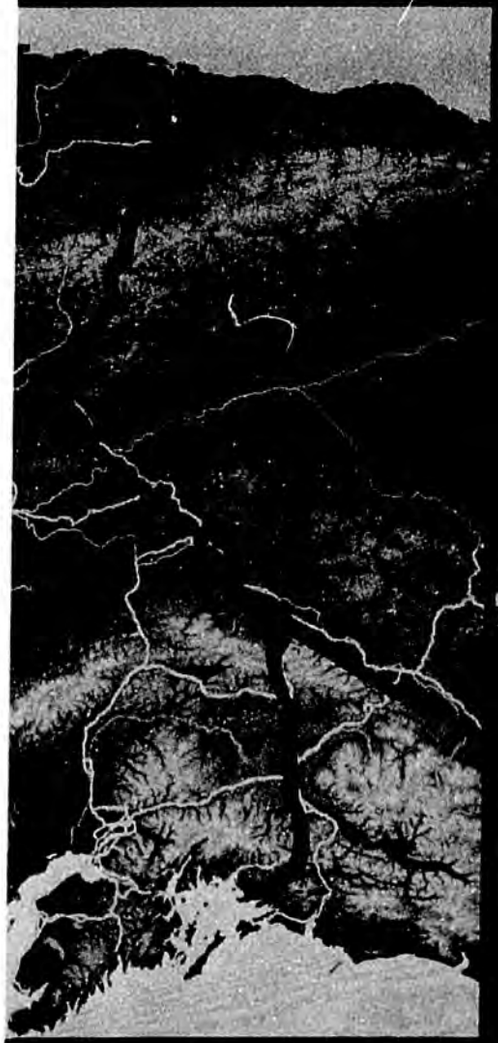
Notes:

1. *The numbers presented are annual figures for the fully ramped-up project.*
2. *Total benefit per MMBtu of gas into GCP less CO2 stream.*
3. *Netback and feedgas pruchase prices are calculated based on total gas flow into the GCP, including CO2 stream and gas for fuel consumption*
4. *Producer benefits are expressed as pre-tax revenues.*
5. *Based on 2.7% pipeline fuel consumption and a $450 MM cost of fractionation plant, amortized over 15 yrs at 12% equity return*
6. *Based on a sales price of $20/bbl and $3.50 TAPS tariff*

Intellectual property of Taylor-DeJongh and
Alaska Gasline Port Authority


ALASKA GASLINE PORT AUTHORITY

Alaska Gasline Port Authority



Board of Directors

North Slope Borough
Mayor George Ahmaogak, Chair
Al Adams
Richard Glenn

Fairbanks North Star Borough
Mayor Rhonda Boyles, Treasurer
Charlie Cole, Vice Chair
Barbara Schuhmann

City of Valdez
Mayor Bert Cottle
Dave Cobb, Secretary
John Kelsey

AGPA

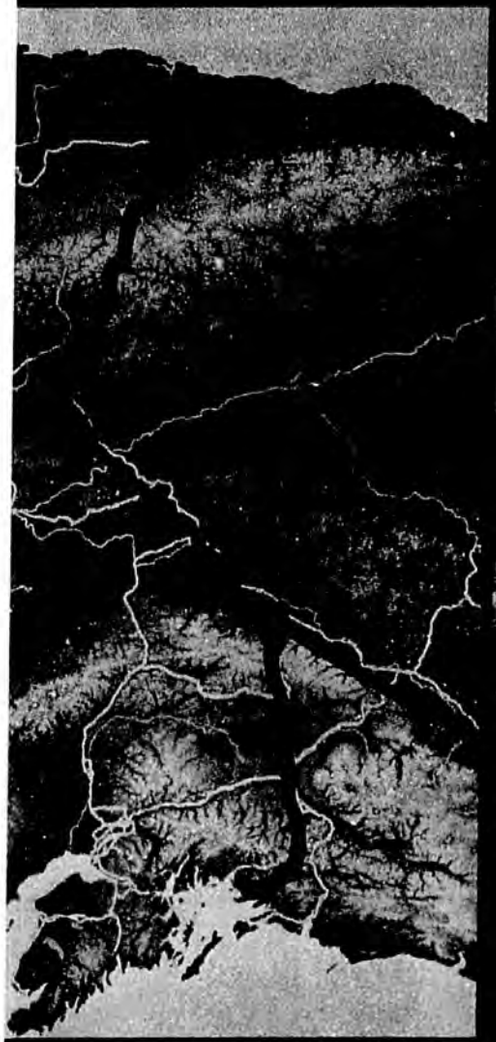
Alaska Gasline Port Authority



The Alaska Gasline Port Authority consists of three municipalities

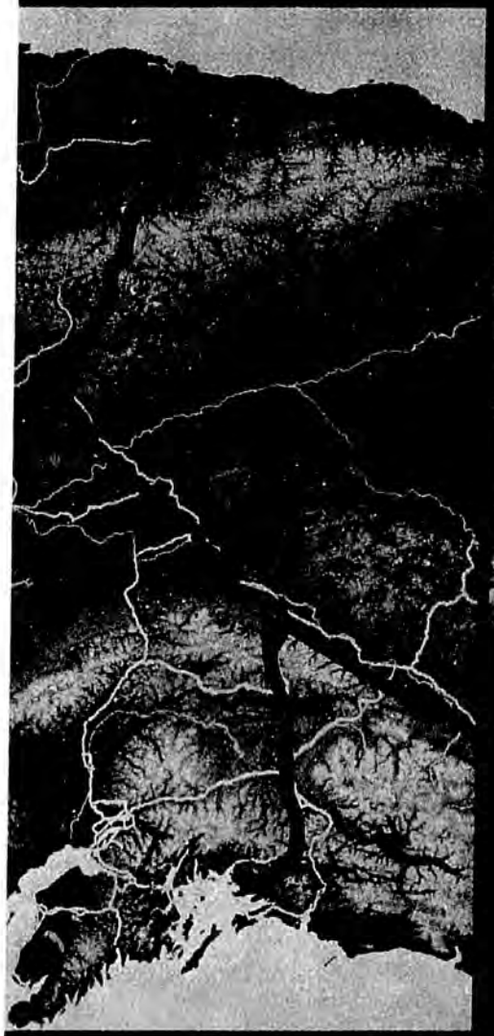
- North Slope Borough
- Fairbanks North Star Borough
- City of Valdez

Alaska Gasline Port Authority's Mission



The mission of the Alaska Gasline Port Authority is to enable the development of Alaska's North Slope gas to the maximum benefit of all Alaskans.

Evolution of the Alaska Gasline Port Authority



- Formed in 1999; ratified by the voters of the three municipalities in October, 1999
- Preparation of the project development plan; engineering, procurement and construction plan; project cost estimate and alternatives analyses
- Preparation of economic and financial models
- IRS granting of federal income tax exemption

The Project Team



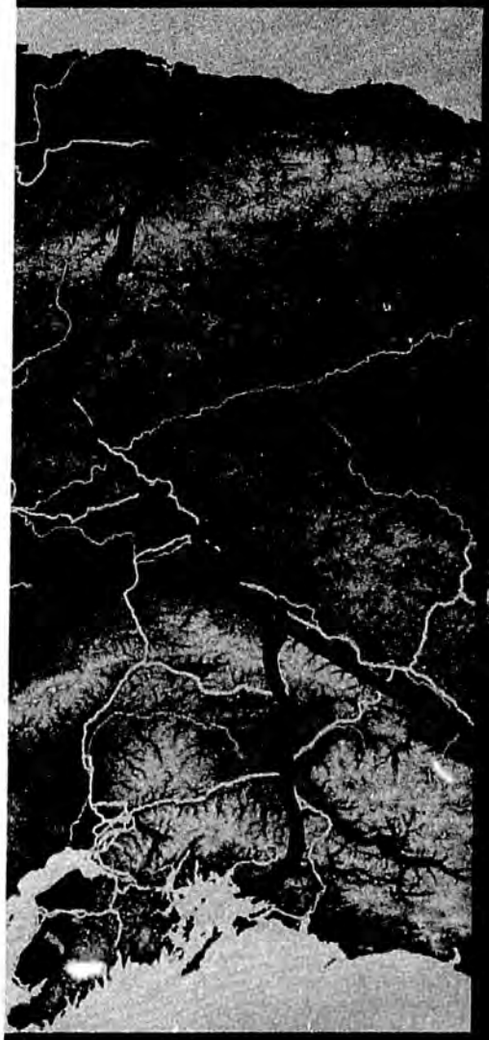
- Alaska Gasline Port Authority
- Bechtel Corporation – technical and development support
- Taylor DeJongh – financial analysis and formation
- O'Melveny and Myers – development counsel
- Walker Walker and Associates – general counsel

Project Scope – Y-Line



- Gas conditioning plant on the North Slope
- 550-mile, 56-inch diameter pipeline from North Slope to Delta Junction
- 150-mile, 44-inch diameter pipeline to Canadian border for interconnect to lower 48
- 256-mile, 46-inch diameter branch line to Valdez
- Spur line to Anchorage from Glennallen
- 15 million ton per year LNG plant, LPG fractionation plant and port facilities in Valdez

Advantages of a Y-Line



Combining a gasline to the lower 48 with a gasline to an LNG and/or GTL project will lower the cost of gas transportation down each branch of the line by approximately 33 percent

Construction Cost



A single line to carry 3 bcf per day = $7.0 billion

A Y-line to carry 3 bcf to the Canadian border and 3 bcf to an LNG/GTL facility = $9.7 billion

$$\frac{9.7}{2} = \$4.85 \text{ billion}$$

Cost of Y-Line for Two Projects



Construction cost

– Conditioning plant (assuming no efficiencies from existing plant)	$ 4.2 billion
– Pipeline (including the two branches)	$ 9.7 billion
– LPG fractionation plant	$ 450 million
– LNG plant and port facilities	$ 3.65 billion
– Construction cost total	$ 18.0 billion

(includes escalation and $1.8 billion contingency)

Cost of Y-Line for Two Projects *(Cont'd)*



Soft costs

– Interest during construction	$ 4.9 billion
– Owner's contingency	$ 900 million
– Debt service reserve	$ 1.0 billion
– Financing fees, working capital, etc.	$ 1.0 billion
	$ 7.8 billion
– Minus pre-completion revenue	-3.2 billion
– Total financing required	$ 22.6 billion

(for both LNG project and pipeline to Alaskan-Canadian border for Lower 48 sales)

Financial Results of the Y-Line



- Producers: $2 billion to $3 billion per year
- State – royalties, severance tax, and corporate income tax: $750 million to $980 million per year
- Payment in lieu of property taxes: $114 million per year
- All Alaskan Community Dividend: $111 million per year
- Assistance to Alaskan communities to lower energy costs: $37 million per year

Benefits – Dr. Pedro van Meurs' Analysis

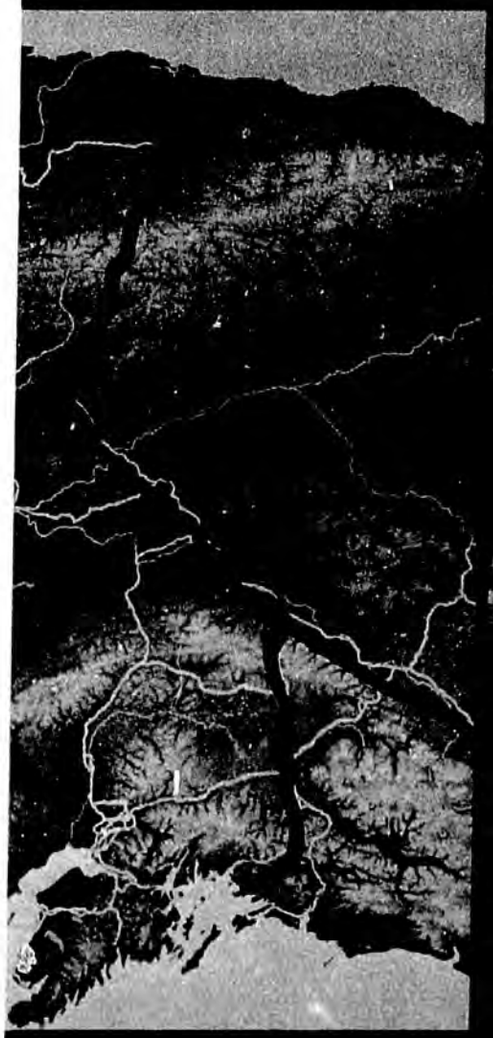


AIDE MEMOIRE
MEETING WITH ALASKA GASLINE PORT AUTHORITY
March 30, 2000
Dr. Pedro van Meurs
Energy Consultant to State of Alaska

VIEW OF THE CONSULTANT

. . . "Based on the above total project configuration, the net benefit of the tax exemptions may range in the order of magnitude of $10 to $20 billion on an undiscounted current dollar basis."

Benefits of Port Authority Ownership



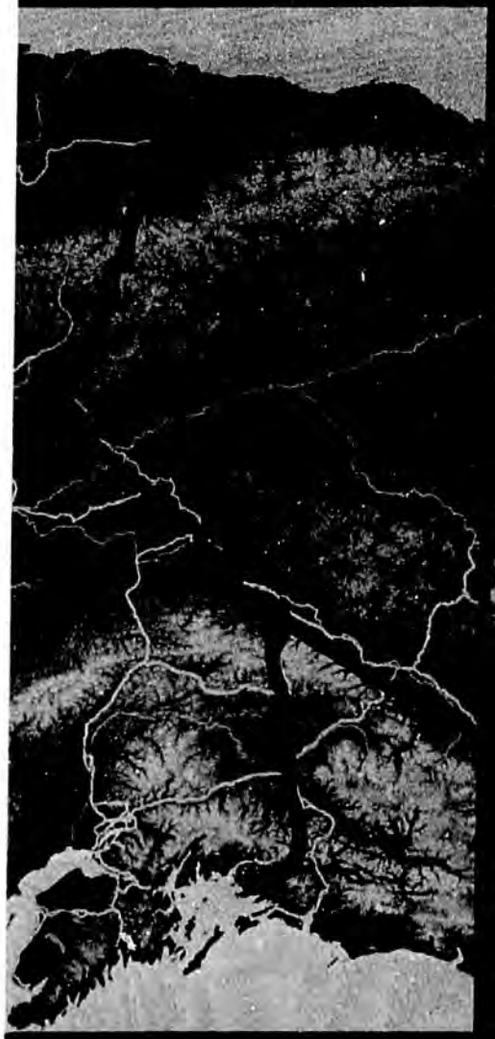
- Guarantees maximum in state usage of North Slope gas
- Income is tax exempt (IRS ruling)
- Port Authority can access 100 percent project financing for the entire project
- Port Authority's required return on investment is substantially lower than a privately-owned project

Benefits of Port Authority Ownership *(Cont'd)*



- Some debt would be financed with tax-exempt bonds
- Port Authority is not subject to FERC regulation
- Annual flow of revenue to state and local communities
- Port Authority creates local ownership of gasline

Benefits of Port Authority Ownership *(Cont'd)*

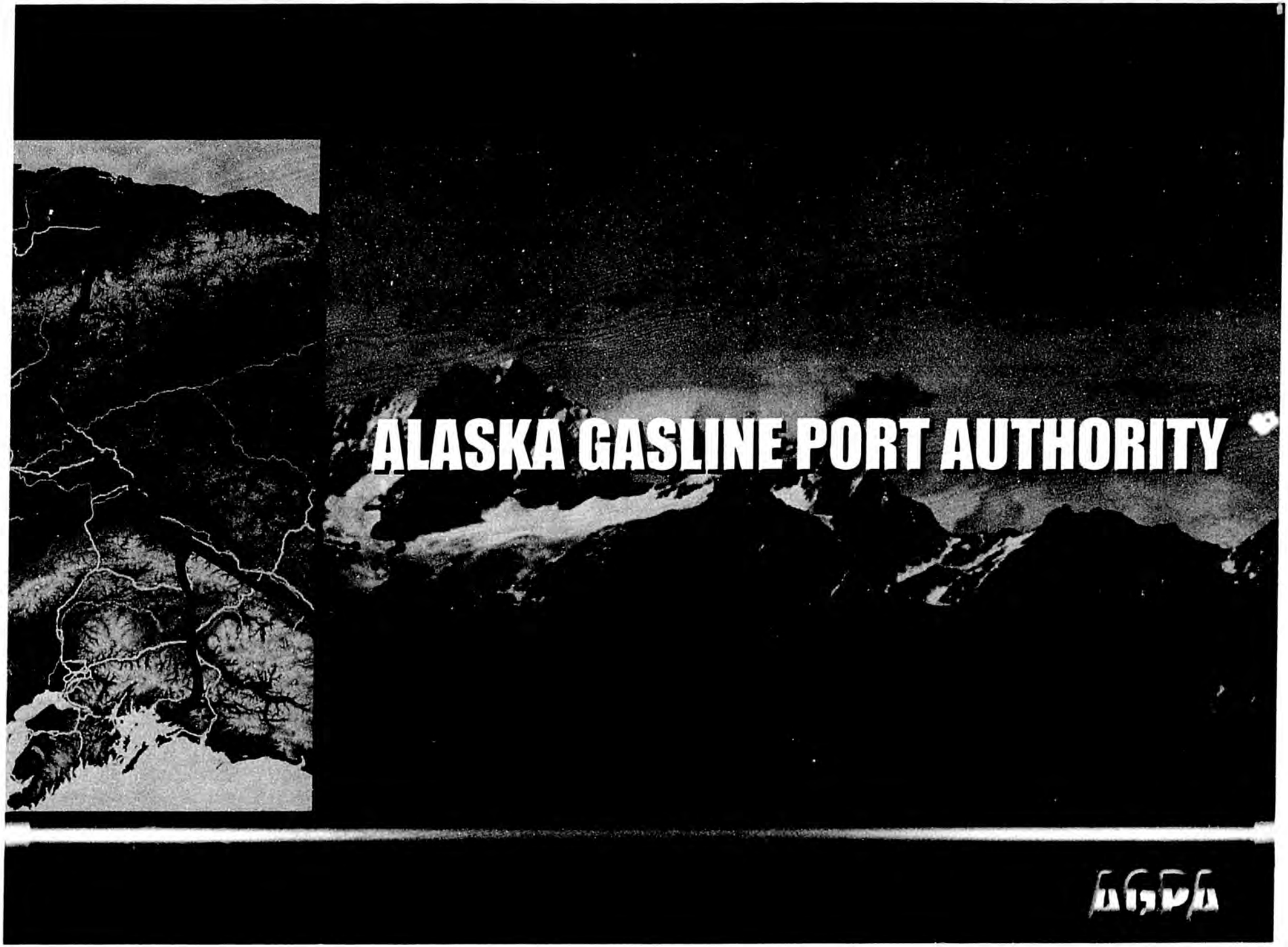


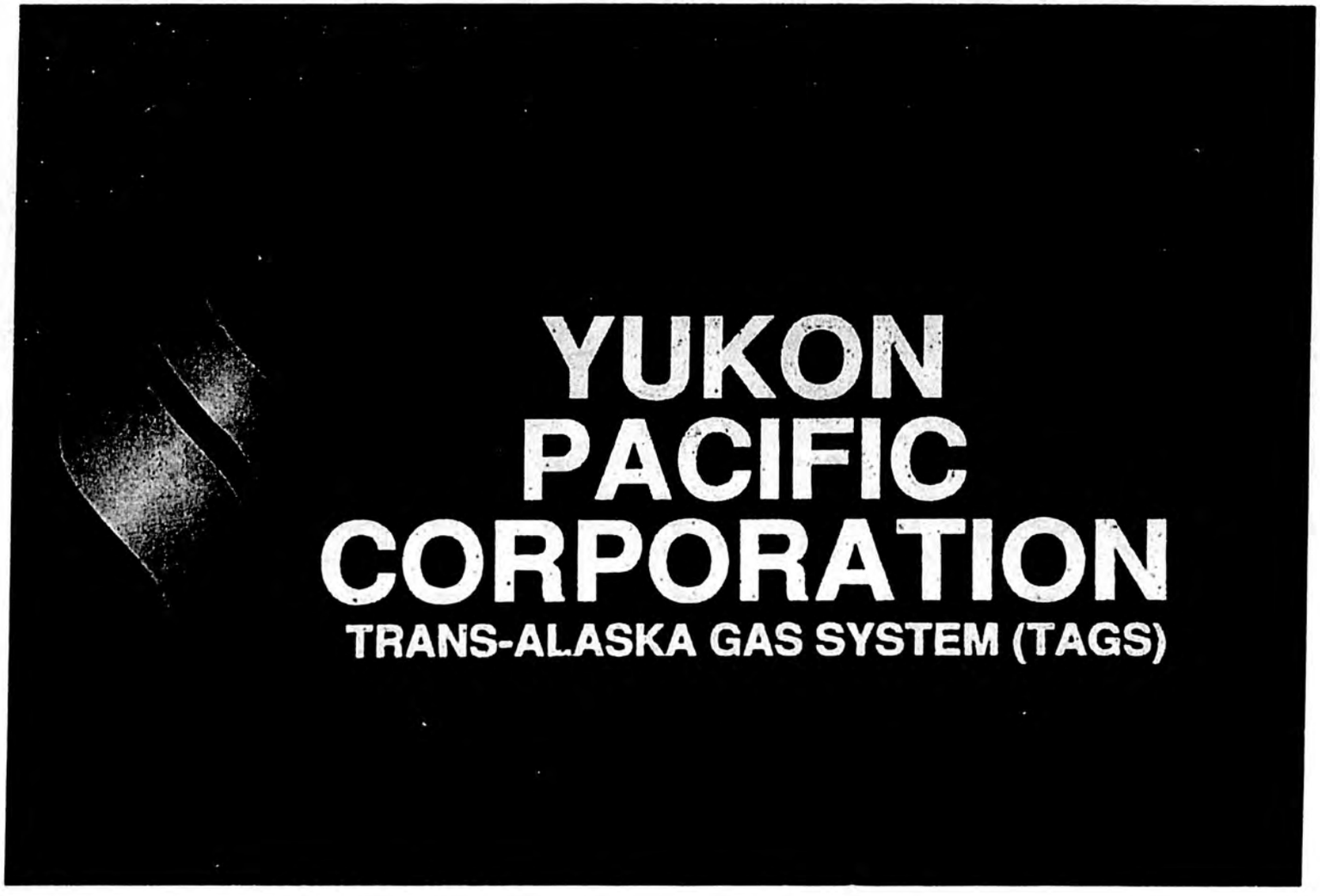
No need to give up state revenue (tax or royalties) to subsidize the project

More certainty of gas available for in-state usage and more control over price

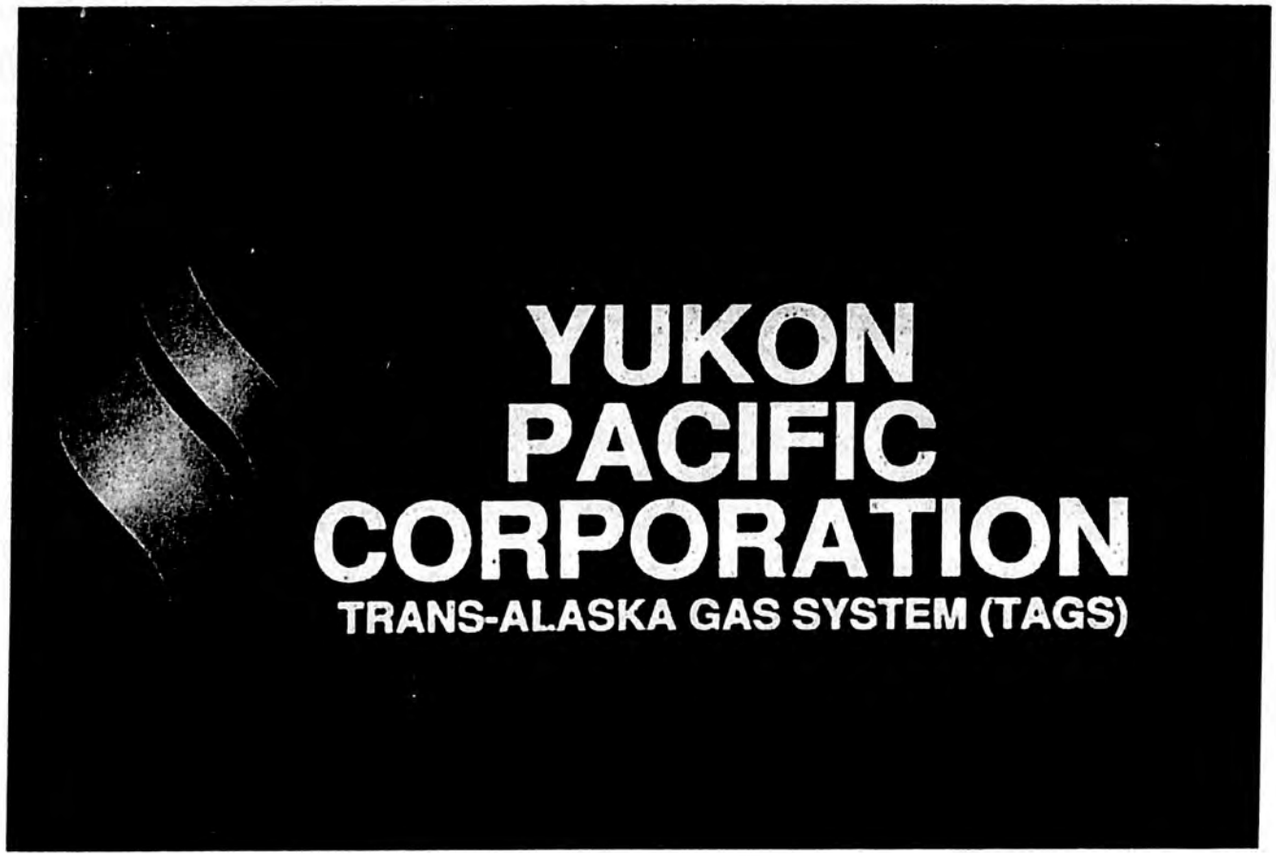
Example:

$3.00	Chicago price per million Btu
-1.20	Transportation cost Alaska-Canadian border to Chicago
$1.80	Total wholesale price to Anchorage or Fairbanks communities

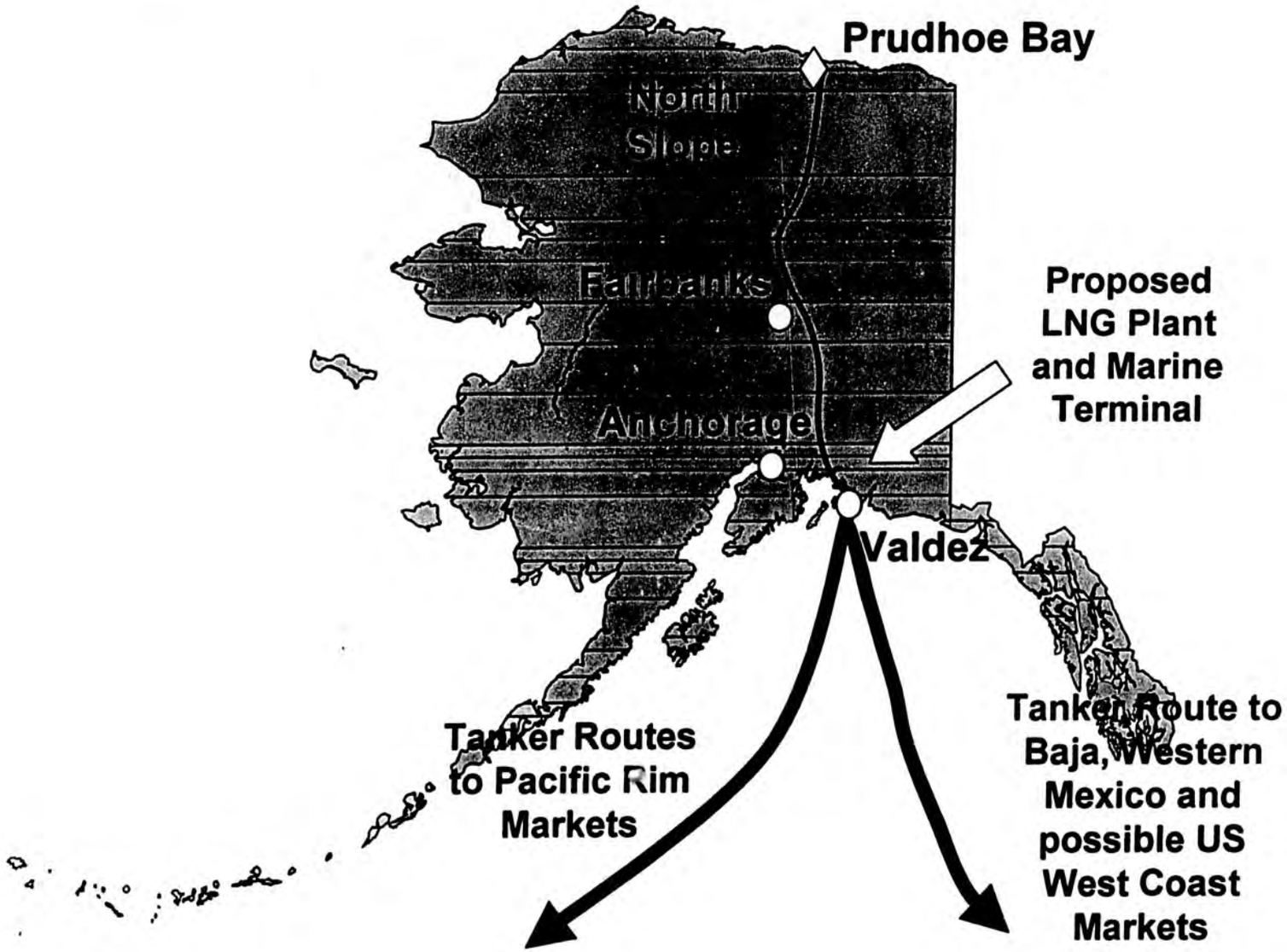

ALASKA GASLINE PORT AUTHORITY


YUKON
PACIFIC
CORPORATION
TRANS-ALASKA GAS SYSTEM (TAGS)

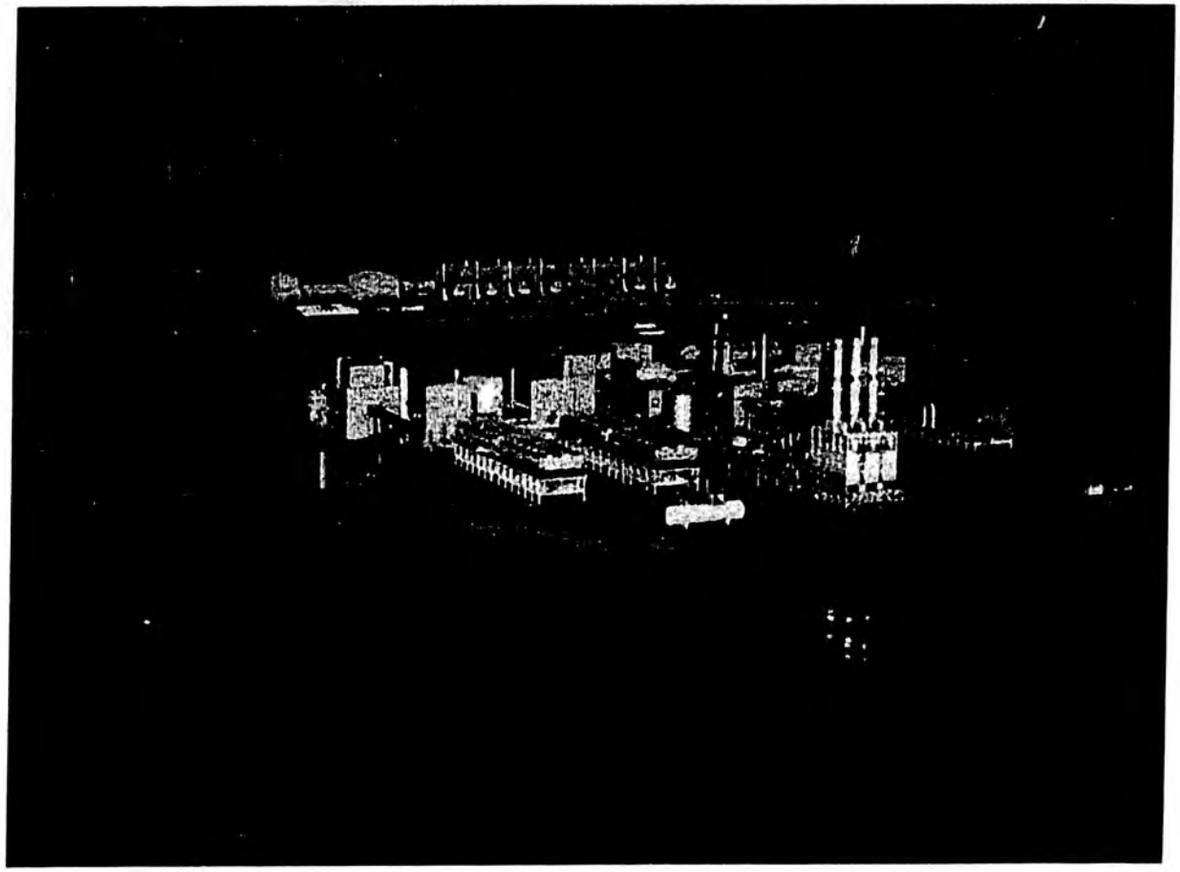
TAGS Components



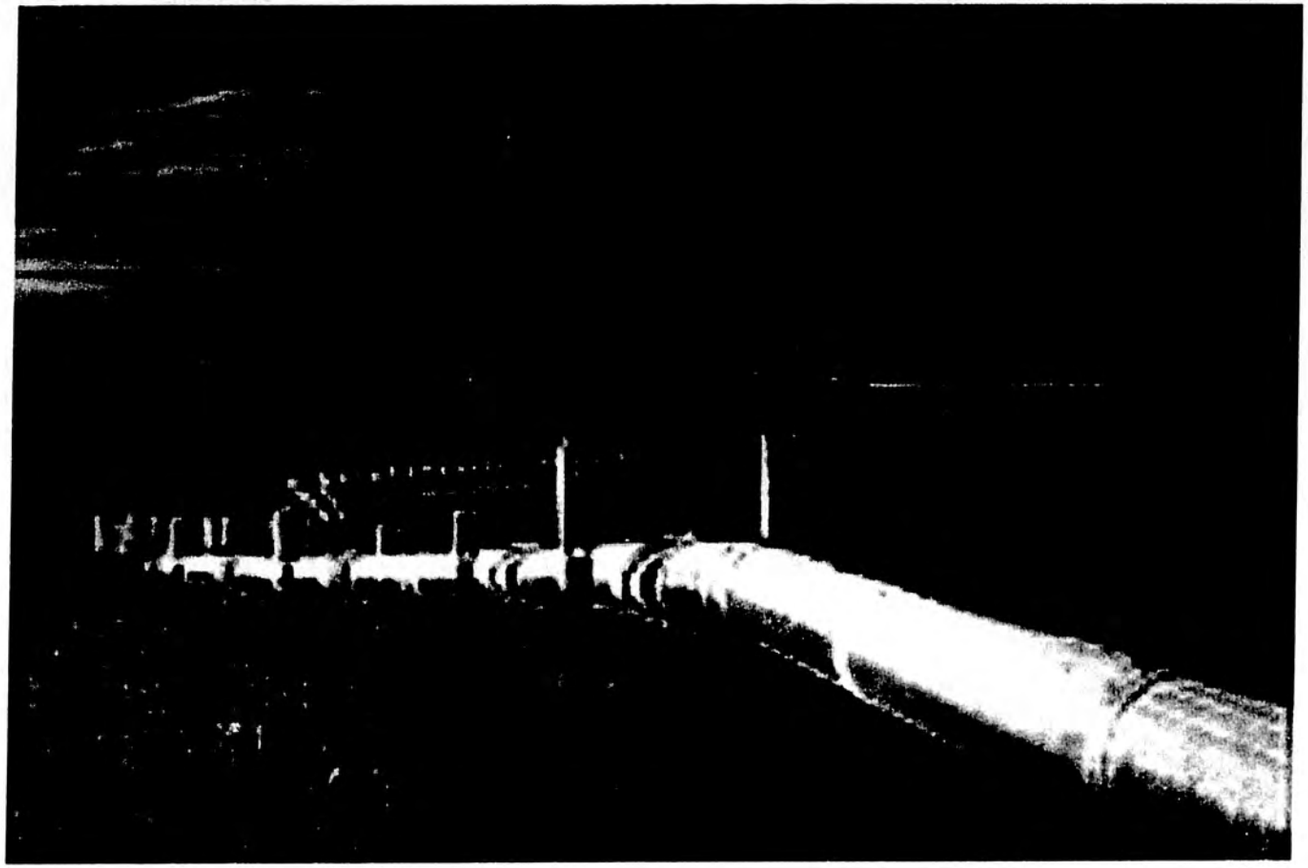
What is the Trans-Alaska Gas System (TAGS) Project?



✓Gas conditioning on the North Slope



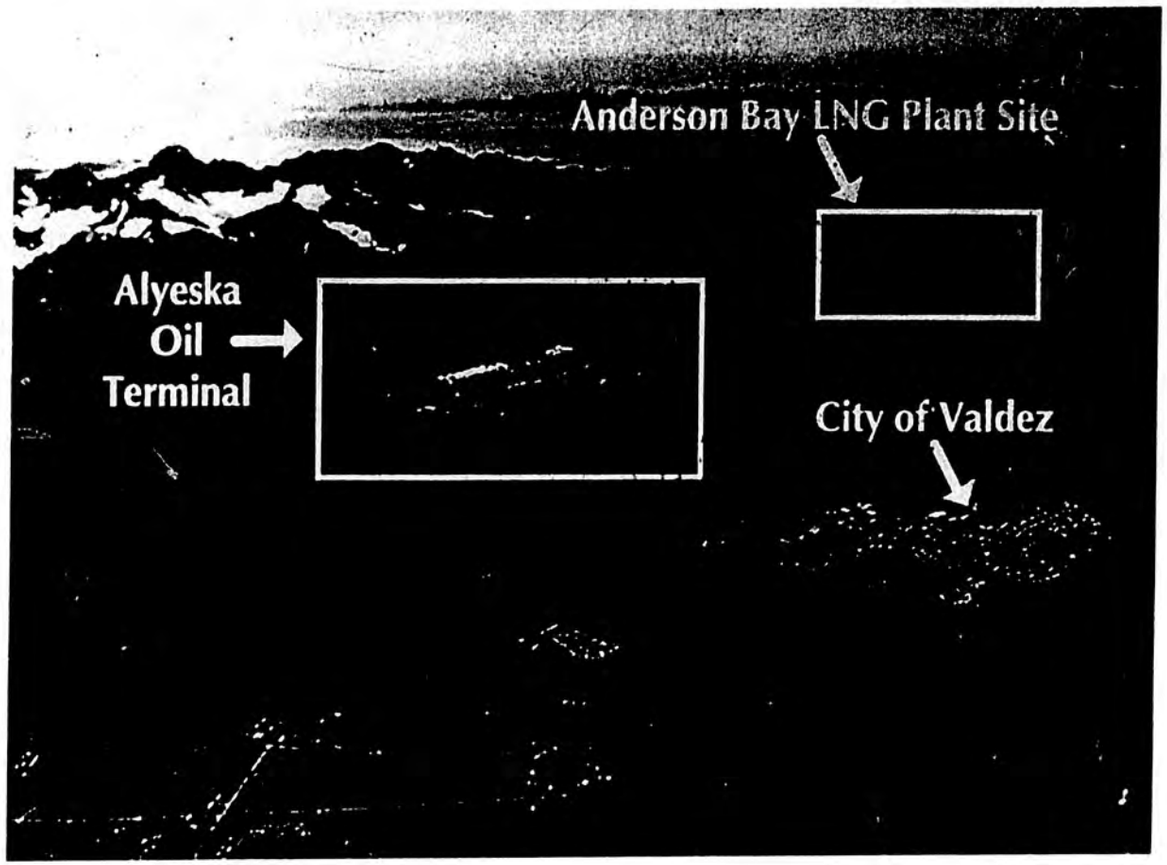
✓Pipeline route to Valdez



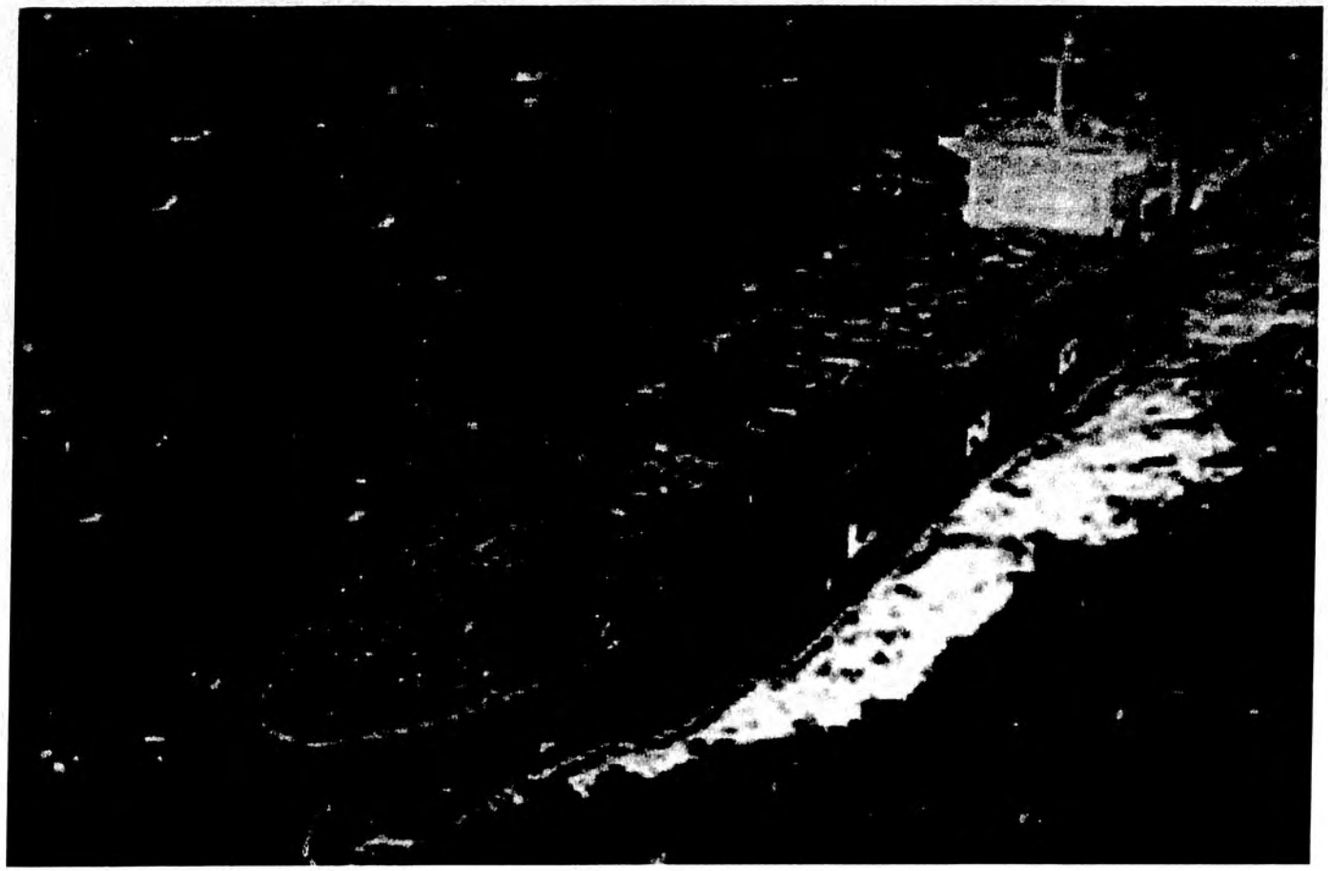
TAGS is in the existing, dedicated pipeline corridor



Port Valdez and Anderson Bay LNG Plant/Marine Terminal



LNG tankers



TAGS Permits and Authorizations

- ✓ Presidential finding approving export of natural gas required under ANGTA
- ✓ Project-wide and site specific (Anderson Bay) final environmental impact statements as required under NEPA
- ✓ Right-of-ways for the 800 miles of pipeline to Valdez
- ✓ US Department of Energy ("DOE") authorization for export of North Slope natural gas
- ✓ Federal Energy Regulatory Commission ("FERC") Anderson Bay final EIS and site license for construction and operation.
- ✓ NPDES Air Permit for LNG site at Anderson Bay

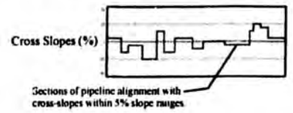
TAGS Permits and Authorizations
(Cont'd)

- ✓ Coastal zone consistency determination
- ✓ Wetlands program continuing

Plan View Abbreviations

Text	Description
TAGS	Trans-Alaska Gas System
TAPS	Trans-Alaska Pipeline System
ANGTS	Alaska Natural Gas Transportation System
MS	Material site
MP	Milepost
APL	Alyeska pipeline access road
AMS	Alyeska material site access road
OMS	Alyeska operations material site access road
PUT	Putilagayuk River material site
CVEA	Copper Valley Electric Association transmission line
GVEA	Golden Valley Electric Association transmission line
JT	Joules-Thompson (Valve)

Cross Slopes



Workpad Type

Code	Description
NO	No workpad
JG	Joint use with gravel
JR	Joint use with rock
SN	Snow
IC	Ice
SG	Structural gravel
SR	Structural rock
FG	Fabric over gravel
FR	Fabric over rock
C	Cut in soil
E	Cut in rock

Ditch Type

Code	Description
CO1	Common ditch, unfrozen, no coarse
CO2	Common ditch, unfrozen, some coarse
CO3	Common ditch, frozen, no coarse
CO4	Common ditch, frozen, some coarse
FP1	Floodplain ditch, unfrozen, <15% coarse
FP2	Floodplain ditch, frozen, <15% coarse
FP3	Floodplain ditch, unfrozen, >15% coarse
FP4	Floodplain ditch, frozen, >15% coarse
BR1	Bedrock ditch in river
BR2	Bedrock ditch in floodplain
BR3	Bedrock ditch in upland area
RC1	River ditch, no coarse
RC2	River ditch, some coarse
SP1	Frost heave ditch design
SP2	Thaw settlement ditch design

Terrain Erosion Potential

- Low
- Medium
- High

Wall Thickness

- Class I (0.713 in.)
- Class II (0.975 in.)
- Class III (1.170 in.)

Stations, Valves & SDA's

- Special Design Area
- Plan view valve location
- Manual ball valve
- Remote ball valve
- Automatic check valve
- JT valve
- Compressor station
- LNG plant & marine terminal

Text	Description
SDA	Special design area
HCA	Highway co-alignment
PDA	Population density area
PCA	Pipeline co-alignment
PAC	Pipeline aerial crossing

Foreign Facility & Stream/River Crossings

Text	Description
TAPS	Trans-Alaska Pipeline System
(A/G)	Above ground mode
(B/G)	Below ground mode
Art	Alyeska river training structure (existing)
Rda	Road, Alyeska access
Rds	Road, secondary (named & unnamed)
Rdp	Road, primary (unnamed)
Sma	Stream major (unnamed)
Smi	Stream minor (unnamed)
Pla	Pipeline (above ground)
Plb	Pipeline (below ground)
Hfl	Human fill
CVEA	Copper Valley Electric Association transmission line
GVEA	Golden Valley Electric Association transmission line

Terrain-Vegetation Type

Text	Description
(GB%)	Percent Grass & Brush
(BT%)	Percent Brush & Small Trees
(LT%)	Percent Light Timber
(MT%)	Percent Medium Timber
(HT%)	Percent Heavy Timber

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This document and the data and information upon which it is based is confidential and/or proprietary to the Yukon Pacific Corporation and neither this document nor the information upon which it is based shall be duplicated, used or disclosed except as authorized in writing by Yukon Pacific Corporation.

Abbreviations and Symbols

None

Civil/Construction Typical Details

Civil-Construction-Typicals(02-01-2000).dwg

No.	DATE	REVISION	BY	APP.
0	12-3-99	Issued for Approval	HMJ	KJM

PAC
HMJ
KJM
Michael Baker Jr., Inc
241068055

TRANS-ALASKA GAS SYSTEM
NATURAL GAS PIPELINE
PRUDHOE BAY TO ANDERSON BAY
YUKON PACIFIC CORPORATION

Not To Scale
Not To Scale
February 1, 2000
3
N/A
N/A
Sheet 01 of 05



Vertical Profile
Vertical Exaggeration = 10:1 Elevation (Feet)

Matchline to Sheet 028 - Station 8319+59.17

Matchline to Sheet 030 - Station 8643+19.95

Station 8320+00 8330+00 8340+00 8350+00 8360+00 8370+00 8380+00 8390+00 8400+00 8410+00 8420+00 8430+00 8440+00 8450+00 8460+00 8470+00 8480+00 8490+00 8500+00 8510+00 8520+00 8530+00 8540+00 8550+00 8560+00 8570+00 8580+00 8590+00 8600+00 8610+00 8620+00 8630+00 8640+00

Terrain Units

Therm. Class

Frost Hv. Pot

Thaw Set. Pot

Moisture Cont

Terrain EP

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Phillip Smith Mountains A-4 & A-5

Upper Atigun River, Atigun Camp

TAGS 1:12000 Orthophoto Based Geotechnical Series

TAGS-1_12-Geol(02-01-2000).dwg

No.	DATE	REVISION	BY	APP.
0	6-15-88	Federal ROW Grant - Exhibit A	ELD	MCM
1	11-1-88	State Cond. ROW Lease - Exhibit C	ELD	MCM
2	2-1-92	Modifications for 42" OD Pipeline	EAW	JDS
3	10-1-99	Environmental alignment revisions	ELD	MCM

MCM
ELD
MCM

YUKON PACIFIC CORPORATION

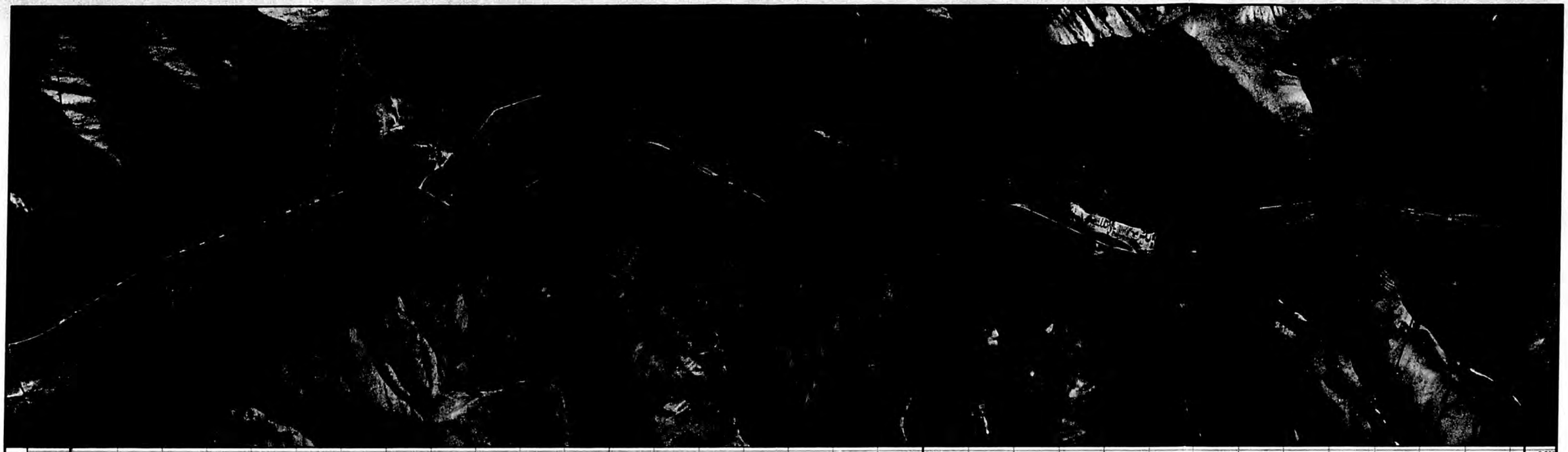
TRANS-ALASKA GAS SYSTEM
NATURAL GAS PIPELINE

PRUDHOE BAY TO
ANDERSON BAY

Horiz. 1" = 1,000 Feet
Vert. 1" = 100 Feet
February 1, 2000 3

8319+59.17 8643+19.95

Sheet 029 of 141



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Project Name: Philip Smith Mountains A-4 & A-5

Project Area: Upper Atigun River, Atigun Camp

Revision Date: TAOS 1 12000 Orthophoto Based Civil/Const. Series

File Name: TAOS-1_12-Civil02-01-2000).dwg

No.	DATE	REVISION	BY	APP.
0	6-15-88	Federal ROW Grant - Exhibit A	FLB	MCM
1	11-1-88	State Const. ROW Lease - Exhibit C	FLB	MCM
2	2-1-92	Modifications for 42" O.D. Pipeline	KAW	JDB
3	10-1-99	Environmental alignment revisions	FLB	MCM

Designed By: MCM

Drawn By: FLB

Checked By: MCM

Approved By:

Revision Number:

TRANS-ALASKA GAS SYSTEM
NATURAL GAS PIPELINE

YUKON PACIFIC CORPORATION

PRUDHOE BAY TO ANDERSON BAY

SCALE: 1" = 1,000 Feet
1" = 100 Feet

Date: February 1, 2000

Begin Station: 8319+59.17

End Station: 8643+19.95

Sheet 029 of 141

Trans-Alaska Gas System
Capital Costs ($US year 2000)

		START-UP	EXPANSION I	EXPANSION II
LNG Delivered	**MTA**	**9.2**	**13.8**	**18.4**
Pipeline Flow	BCFD	1.2	1.8	2.5
LNG Trains		2	3	4
Pipeline and Stations (1)	$billion	3.7	0.2	0.4
LNG Plant & Terminal (2)	$billion	2.3	0.9	0.8
Incremental Capital Cost	$billion	6.0	1.1	1.2
Cumulative Capital Cost	**$billion**	**$6.0**	**$7.1**	**$8.3**

(1) Source: Willbros Engineering and Michael Baker Jr.

(2) Source: Kellogg Brown & Root and Air Products and Chemicals, Inc.

Developing Alaska's North Slope Gas Is A Challenge

The cast of characters. . .

1970 - 2001

Arctic Gas

El Paso

Northwest/Foothills

ACETS

MACPORC

Kivalina/Wainwright

GTL

ARC

LNG Sponsor Group

YPC/TAGS

In the 1970's, Congress considered three project options to supply North Slope gas to the lower 48

- ✓ Arctic Gas ("over the top")
- ✓ El Paso (LNG)
- ✓ Northwest/Foothills (ALCAN)

25 years later the
same three project options
remain,
they are just larger. . .

What has changed in the last 25 years is that large Asian, US and Mexican LNG markets have emerged and North Slope gas can now serve **more than one market!**

Until a year ago people used to talk about 2 bcfd from the North Slope as being a huge project. . .

Now they *routinely* talk about 4 bcfd!!!

So today let's discuss various configurations of a 4 bcfd LNG project, then talk about how North Slope gas can serve **multiple markets**.

First:

A 4 bcfd TAGS LNG project serving North America

(This allows an "apples to apples" comparison with the 4 bcfd "overland" options being discussed)

"Apples to Apples"
Comparative Cost Estimates
Extrapolated from TAGS (US$ yr 2000)

		ALCAN To Alberta	TAGS to North America	TAGS Current
LNG Delivered	MTA		**30**	18.4
Pipeline Flow	BCFD	4	**4**	2.5
LNG Trains			**5**	4
Gas Conditioning (1)	$billion	2.7	**3.5**	
Pipeline and Stations	$billion	10.2	**4.7**	4.3
LNG Plant & Terminal	$billion		**5.4**	4.0
Total Capital Cost (2)	**$billion**	**$12.8**	**$13.6**	$8.3

(1) Rough estimate - difference due to level of CO2 removal

(2) Excludes NGL removal (ALCAN) and LNG receiving terminal(s)

Comparison of 4 bcfd projects: ALCAN and TAGS to North America

- Capital cost of TAGS and ALCAN project to Alberta differ by less than 6 percent (cost-of-service is about the same)
- Pipeline tariff from Alberta to Canadian/US border with Lower 48 is about the same as the LNG tanker tariff (about $0.50/mmbtu)
- Fuel consumption is about the same
- Cost of NGL removal for ALCAN (~$2 billion) assumed the same as cost of LNG receiving terminals

Conclusion:

Cost to deliver 4 bcfd of North Slope gas to west coast of North America as LNG

is about the same as cost to deliver 4 bcfd to Canada/Lower 48 border via ALCAN pipeline

Regulatory issues regarding a 4 bcfd LNG project to North America

- ANGTA benefits are restricted to ALCAN route, Alaskan LNG to North America may involve some ANGTA issues ("over-the-top" route has same issue)

- The Federal Energy Regulatory Agency may have jurisdiction over pipeline where as it currently does not with the TAGS pipeline (intrastate pipeline to LNG export site at Valdez)

- Existing TAGS permits can be used for 4 bcfd project serving Asia, Mexico or US West Coast

In Addition:

A North Slope to Valdez LNG project can serve International as well as Domestic Markets

LNG Market #1:

West Coast of North America

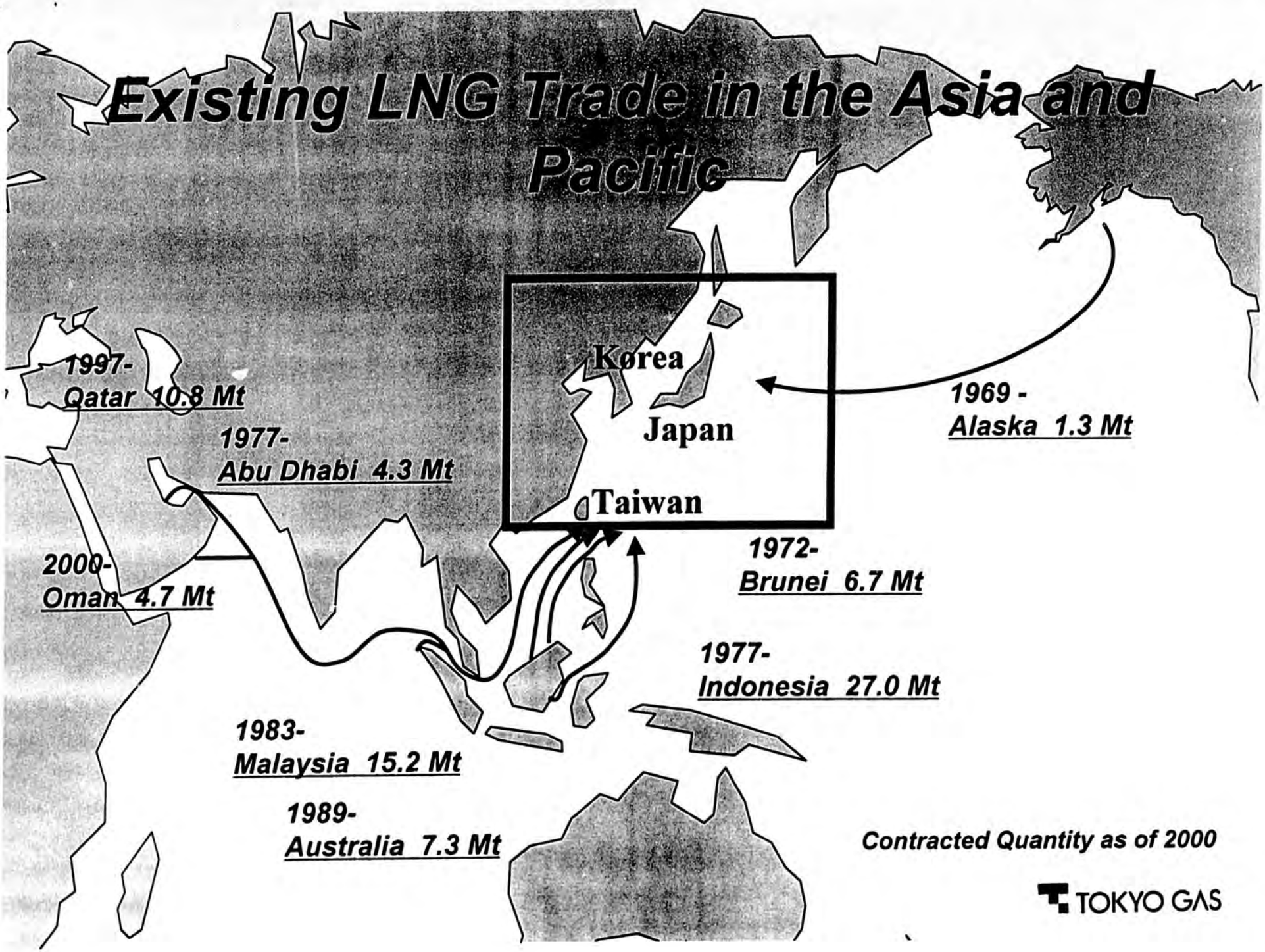
- Numerous LNG projects serving the US West Coast and Mexico have recently been announced – an LNG market exists in the Lower 48

- Similar to the overland pipeline options, increasing the size of the TAGS project (4 bscfd) provides economies of scale to help Alaskan gas compete for the North American LNG/gas market

- Similar to the overland pipeline options, Alaskan LNG represents a secure "domestic" supply to US markets

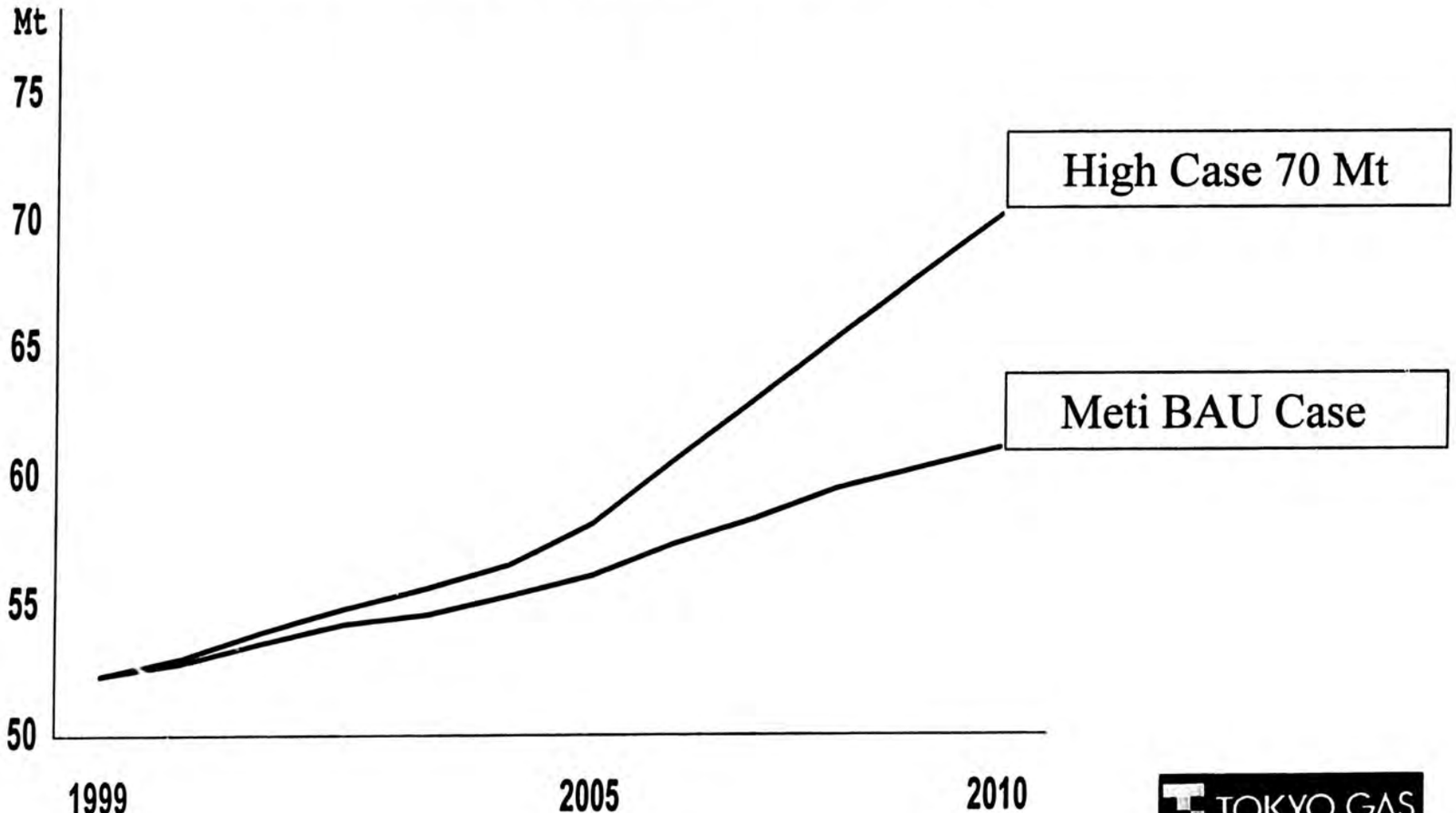
LNG Market #2:

Asia


Existing LNG Trade in the Asia and Pacific
Korea
Japan
Taiwan
1997-
Qatar 10.8 Mt
1977-
Abu Dhabi 4.3 Mt
2000-
Oman 4.7 Mt
1969 -
Alaska 1.3 Mt
1972-
Brunei 6.7 Mt
1977-
Indonesia 27.0 Mt
1983-
Malaysia 15.2 Mt
1989-
Australia 7.3 Mt
Contracted Quantity as of 2000
TOKYO GAS

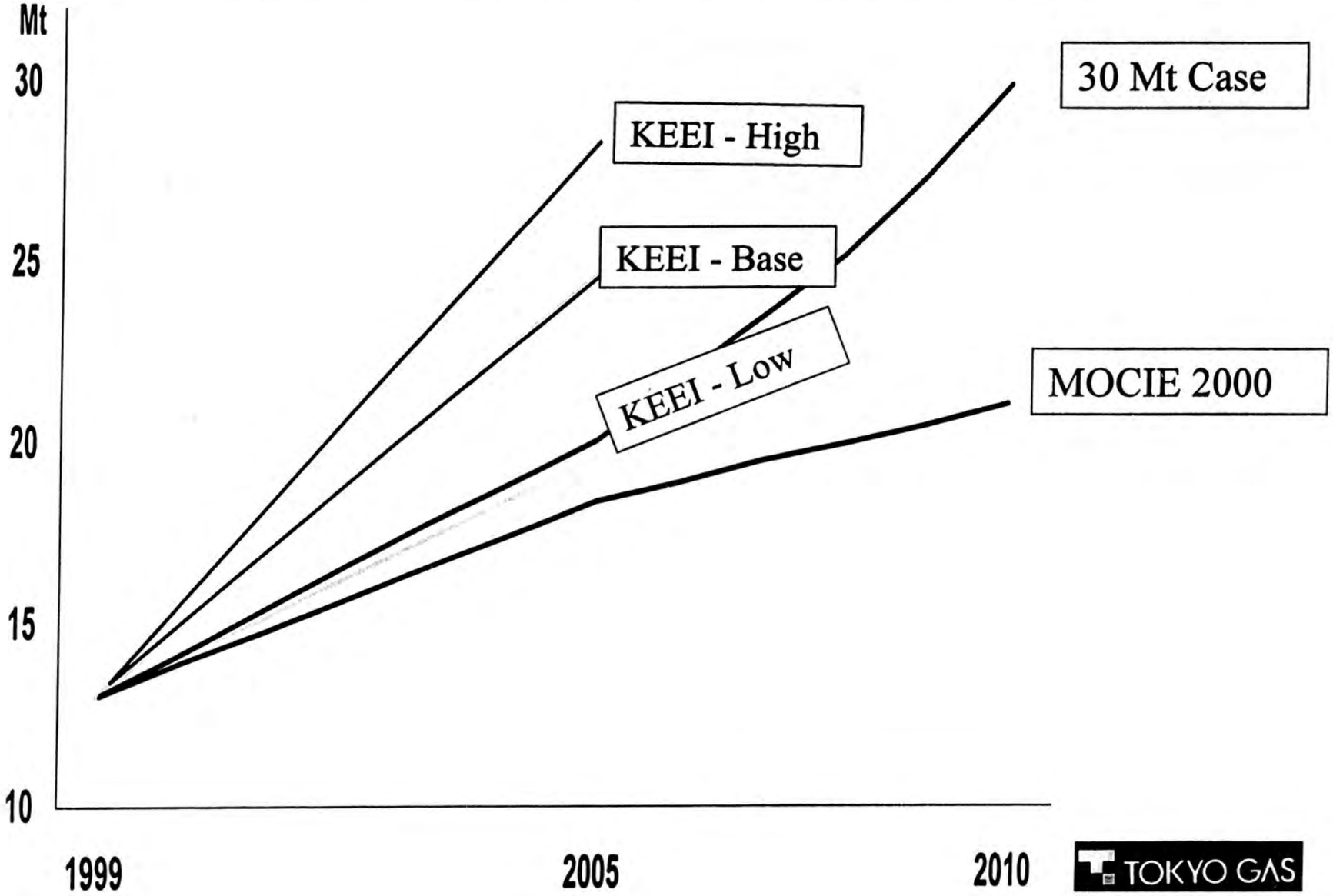
LNG Demand Outlook – Japan

- **Moderate energy demand growth - 1.1%**
- **Slow Development of Nuclear Power**
- **Increased concern on GHG emission**



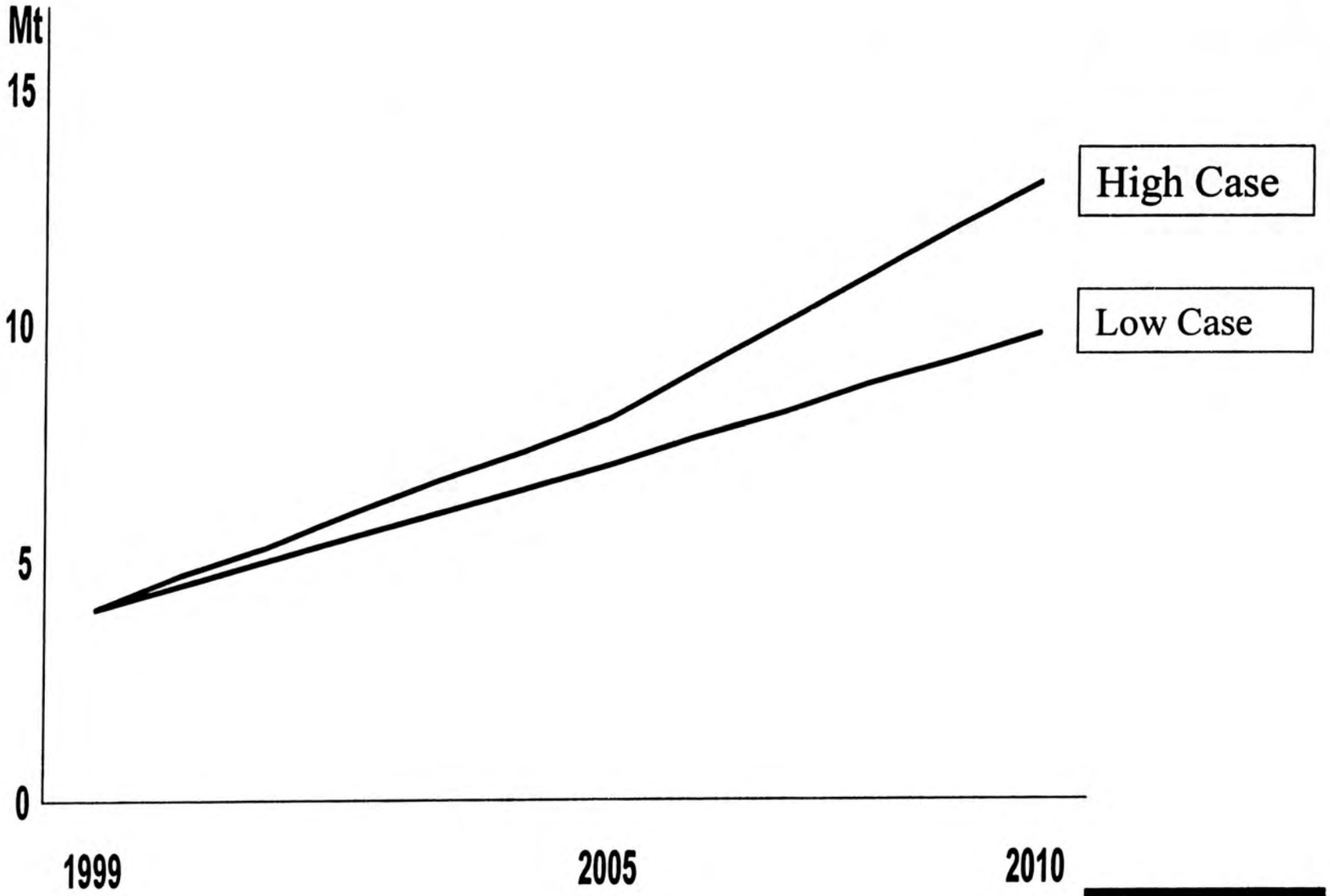
TOKYO GAS

LNG Demand Outlook – Korea



TOKYO GAS

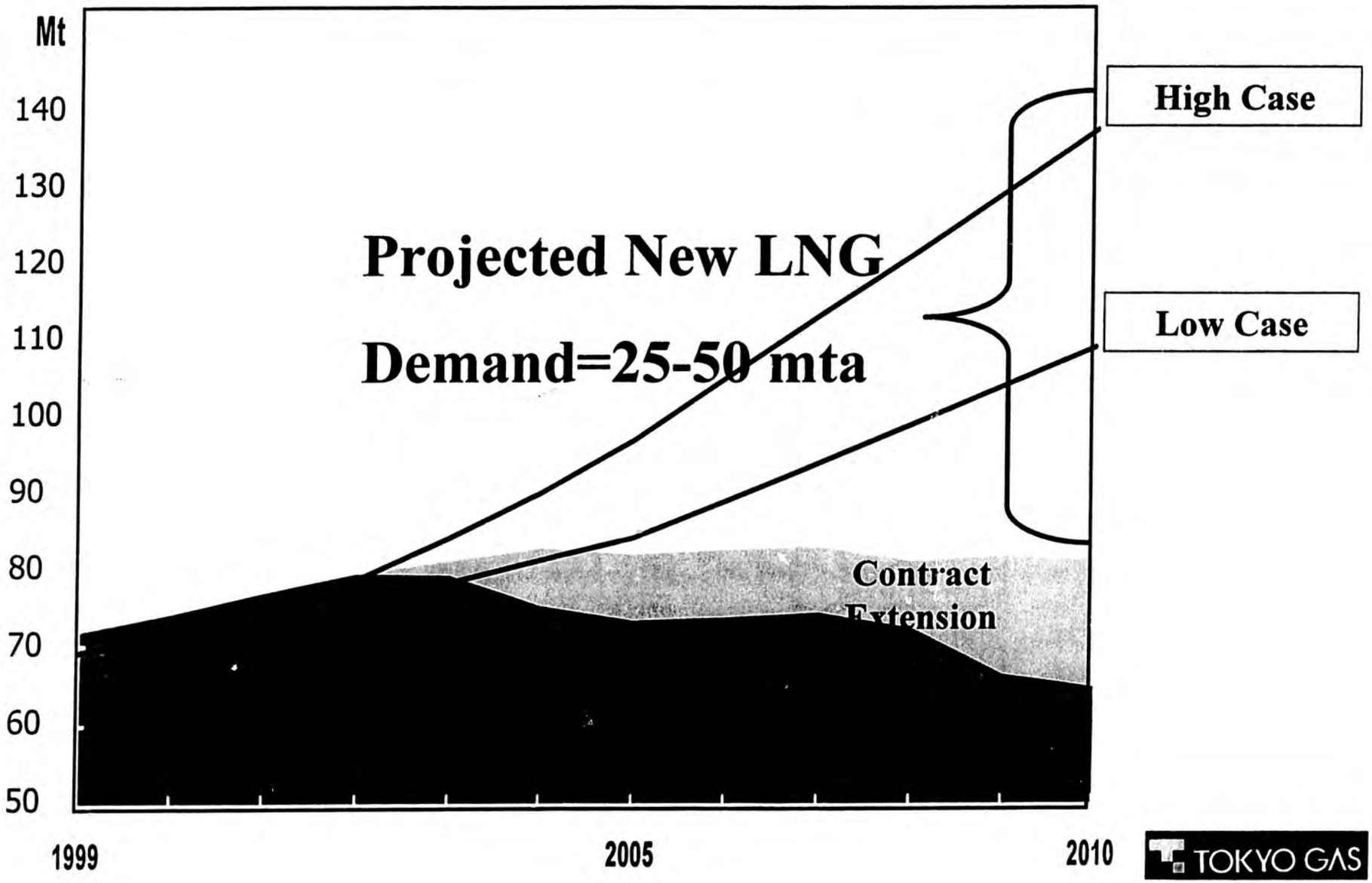
LNG Demand – Taiwan



TOKYO GAS

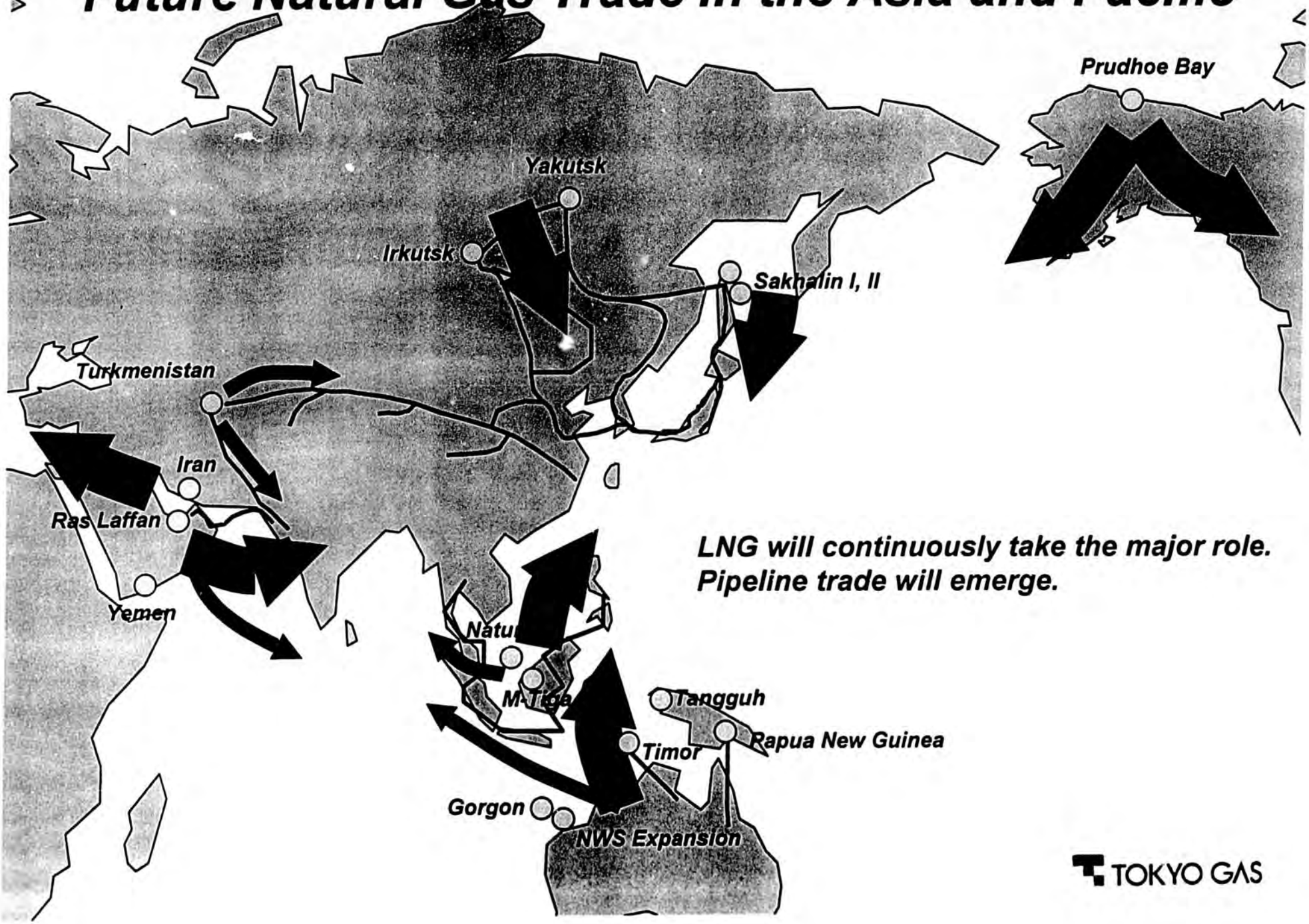
ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672
2947 SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPLINE, 2001-02

LNG Demand Outlook in Asia and Pacific



TOKYO GAS

Future Natural Gas Trade in the Asia and Pacific



LNG will continuously take the major role.
Pipeline trade will emerge.

TOKYO GAS

New Asian LNG demand by year 2010 = 50 mta!

Asia is Alaska's largest trading partner

- Seafood
- Timber
- Coal
- LNG … since 1969!
- Why not more LNG?

Asian LNG Prices

Buyer	Seller	Jan. '01 $/mmBtu
Japan	Abu Dhabi	4.81
	Alaska	4.54
	Australia	4.89
	Brunei	4.65
	Indonesia	4.98
	Malaysia	4.80
	Oman	5.17
	Qatar	5.05
	AVERAGE	***$4.88***

WGI March 8, 2001

- SUSTAINED gas prices in Asia have historically been much higher than in the Lower 48
- When gas prices are high in the Lower 48 they are even higher in Asia

TAGS "Cost of Service" to Asia clearly shows that Alaska gas is commercial

TAGS estimated "cost of service" to Japan (excluding fuel and wellhead price) $/mmbtu delivered, 13.8 MTA/LNG

	Low	High
Alaskan facilities	$1.99	$2.21
LNG tankers	$0.70	$0.70
Total	**$2.69**	**$2.91 mmbtu**

NOTE: January 2001 landed LNG price paid in Japan = **$4.88 mmbtu***

*Average prices in Japan, Korea and Taiwan over the last 6 months are within this same range.

Future Asian LNG Markets and TAGS: A Summary

- ✓ Projected new LNG demand in Asia (Japan, Korea, Taiwan) by 2010 = 50 mta
- ✓ TAGS is commercial at 13.8 mta
- ✓ TAGS "cost of service" (ex. fuel, wellhead price) to Japan = $2.69-$2.91 mmbtu
- ✓ Japan landed LNG price Janurary 2001 = $4.88 mmbtu

LNG Market #3

In State Use

In-State Use:

✓Fairbanks, Valdez, others

✓3 out of 4 Alaskans rely on Cook Inlet gas. . . but the resource is in decline

✓TAGS can still deliver North Slope gas in time to offset this decline

Potential configurations of a Valdez-based LNG project

Potential configurations of the TAGS project

1. Stand alone at Valdez with LNG export only to Asia (current TAGS configuration)

2. Stand alone at Valdez with LNG only to North America (4 bcfd option just discussed)

3. In combination with an ALCAN pipeline project via a Y-line to Valdez from Delta Junction

4. Stand alone at Valdez with LNG delivery to both North America and Asia (LNG supply hub in Valdez)

An LNG "Y" or hub at Valdez has intriguing advantages

- Both smaller Asian and Lower 48 projects can be considered thereby providing benefits of economies of scale while enhancing entry into both markets

  Example: 4 bcfd (30 MTA) LNG project

  - ✓ 1 bcfd (8 MTA) to Asia
  - ✓ 3 bcfd (22 MTA) to North America

- LNG sold to Asia will provide more revenue than sale to Lower 48 thereby improving overall project economics
- Project infrastructure is entirely within Alaska, thus benefits of any US federal or state financial assistance remain in the US
- International political issues are minimized
- Flexibility to accommodate changing market demands over time by simply redirecting LNG tankers

LNG Positives

- It is portable and can serve multiple markets.
- Alaska LNG offers diversity of supply from the world's most stable supplier. Alaska has been an extremely reliable supplier to Japan for 32 years.
- Asian LNG supply projects are backed by very long term contracts with world's largest utilities.
- All potential TAGS configurations can use YPC existing permits.

Three Key Points

1) When "comparing" alternative project economics, always start with the same daily gas volumes entering the pipeline on the North Slope. "Apples to apples."
2) 2005-10 Asian LNG demand is easily large enough to enable TAGS to achieve required economies of scale to be commercial.
3) The Asian LNG market is not based on speculative commodity pricing like lower 48 natural gas. Instead, very long term contracts are standard.

Summary:

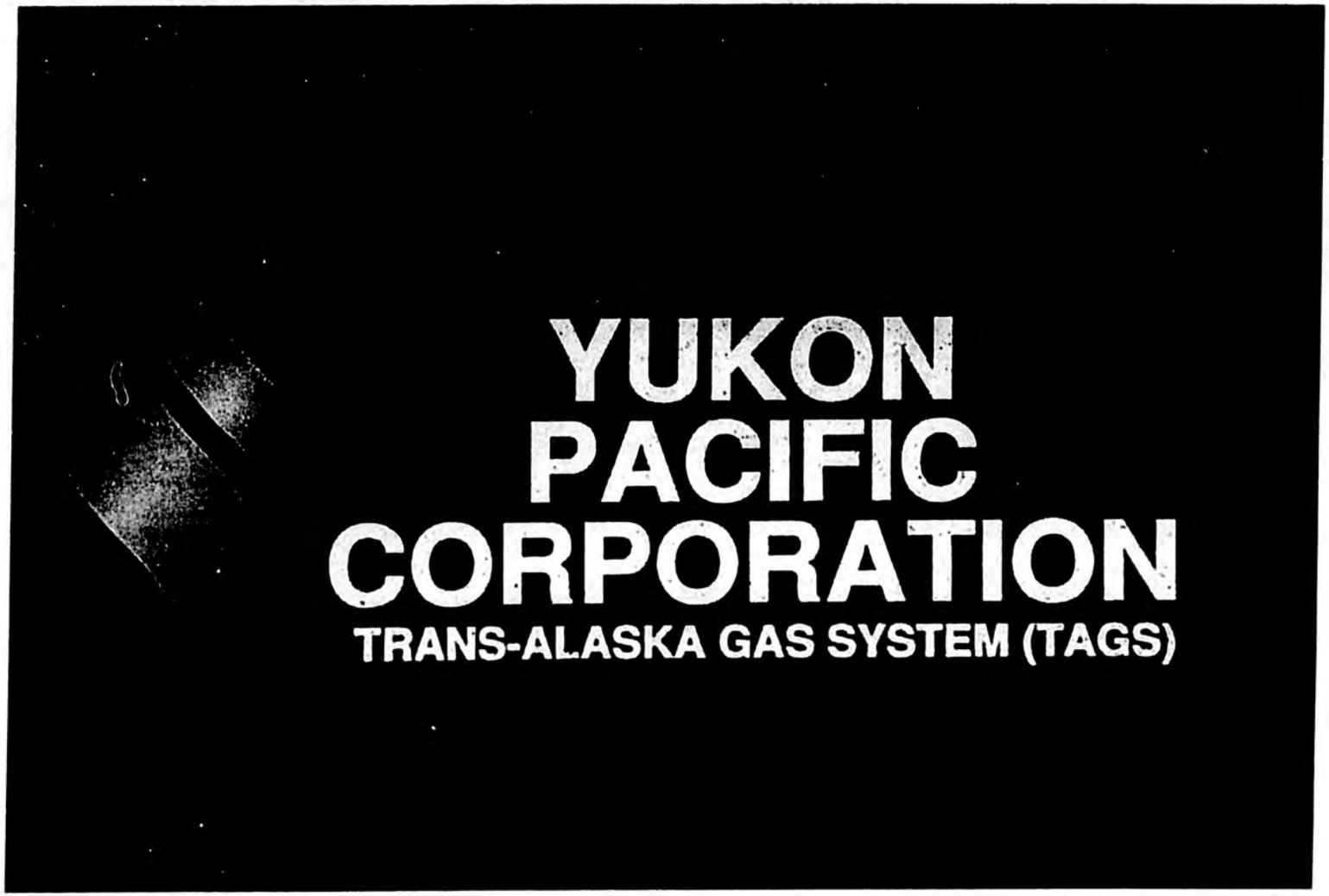
1. **Development of North Slope gas has been and will be challenging; project size has increased to provide benefits of economies of scale.**

2. **The economics for shipping large amounts of gas to the US West Coast as LNG are about the same as for an ALCAN project delivering gas to the Canada/Lower 48 border.**

3. **A LNG project to the US West Coast must address provisions in ANGTA.**

4. **An LNG project is compatible with an ALCAN pipeline project (Y-line at Delta Junction).**

5. **A LNG hub in Valdez allows Alaskan gas to serve multiple markets including the Lower 48, Mexico, Asia and possibly more.**


YUKON
PACIFIC
CORPORATION
TRANS-ALASKA GAS SYSTEM (TAGS)

April 10, 2001

Dear Highway Gas Policy Council Member:

Attached is a seven-page paper prepared by Yukon Pacific Corporation in which we challenge and correct several core assumptions regarding the LNG alternative examined in the Purvin & Gertz report entitled "Alaskan Gas Development Strategies". This report was distributed to a number of paid subscribers and sponsors (including the State of Alaska, several legislators and many private companies) last year and has been cited publicly on a number of occasions following its release.

Since Yukon Pacific was not a subscriber (nor, incredibly, were we ever consulted by Purvin & Gertz in the course of their work on this report in connection with ***any*** of the unique characteristics of a North Slope-sourced LNG project which are the subject of our attached paper), we have only recently reviewed this document and had an opportunity to analyze it and compile these comments. This is extremely unfortunate because we believe that the report was relied on by the Governor and his staff to conclude that "My Way is the Highway." As you will see, had the *true numbers* been included, this might not have been the case.

I know you will find a few minutes to read the attachment to this email. After doing so, please feel free to contact me or my staff with any questions you may have. We are quite convinced that our numbers for OUR project are the most exact and correct available and should be used when analyzing the results of the Purvin & Gertz report.

We sincerely appreciate the time and effort you are devoting to this vital issue. In particular, I want to thank you for inviting me to speak to your group last week on behalf of YPC. I hope my remarks were useful to you and the essential work the Governor has asked you to do.

Sincerely,

Jeff Lowenfels,
President and CEO
Yukon Pacific Corporation

CONFIDENTIAL

The following comments have been prepared by Yukon Pacific Corporation following an extensive review of a confidential report authored by Purvin & Gertz, Inc. (P&G) entitled "Alaskan Gas Development Strategies". The remarks offered and changes proposed below refer to numbers, assumptions and values in the Purvin & Gertz document that are confidential and are provided for the purposes of internal review of the report.

Summary

This analysis shows that several important elements used in the P&G evaluation of the North Slope-sourced LNG project alternative should be changed to properly reflect the potential for a *much higher* netback value (over $1.00 per million Btu, nearly 5 times greater than the $.22 figure used) to Producers and the State of Alaska. These changes are discussed in detail below and involve incorrect assumptions in the P&G report relating to projected LNG prices in Japan, LNG plant operating costs, LNG plant capital recovery costs and pipeline cost of service. ***Except for the issue of projected LNG prices in Asia, this occurred because of P&G's misapplication of "generic" LNG project design and cost factors in its analysis rather than employing the innovative design efficiencies and resulting cost savings benefits unique to the permitted TAGS LNG project.***

Among other gas commercialization alternatives analyzed in the report, P&G assesses the potential netback for a new, generic, world-scale LNG export project requiring an 800 mile natural gas pipeline from the North Slope to a production facility and marine terminal located on the south shore of Alaska. P&G reports the following values, again, for a generic LNG project (Figure VII-18 on page VII-23):

	$/mmbtu
1.) CIF Japan price	3.34
2.) Marine transport	0.65
3.) LNG plant operating costs	0.40
4.) LNG plant capital recovery costs	0.93
5.) Pipeline cost of service	1.14
Producer netback	**0.22**

A. LNG economic analysis

Using the above factors with "corrected" (and most definitely CORRECT) information produces considerably different and *far more positive* results for the Producer (and State) netback for the Alaska LNG project.

1.) CIF Japan price

P&G's projected prices for LNG appear to be low.

The $3.34/mmbtu is the "lower tier price" per P&G. The table entitled "FORECAST DELIVERED LNG PRICE TO JAPAN, EXISTING CONTRACT INDEXATION (2000$)" (page VII-10) shows the following (note: JCC is the abbreviation for "Japan Crude Cocktail"):

Year	2000	2005	2010	2015	2020	
JCC, $/bbl	26.79	20.95	19.40	19.18	19.15	
LNG $/mmbtu	3.82	3.37	3.32	3.31	3.30	
BTU parity $/mmbtu	4.58	3.58	3.32	3.28	3.28	at 5.85 mmbtu/bbl

The JCC $/bbl are lower than the crude oil forecast of the US Department of Energy, EIA published in their AEO 2001 report. Perhaps some further review of world oil price forecasts would be beneficial.

Data from the Sumitomo Corporation shows that LNG price exceeded JCC price (on a $/mmbtu basis) from 1987 through the beginning of 1999. The P&G chart on page VII-10 shows that they analyzed LNG prices during the year of 1999 during which world energy prices increased dramatically. Their analysis thus reflects atypical conditions.

P&G correctly notes that LNG prices are generally indexed to oil price. However, only some of the contracts index immediately with changing oil prices. Those contracts with a delayed indexing would tend to slow the rate at which LNG prices would catch up with a change in oil price. P&G does not address this lag in LNG price indexing, thus one would expect the LNG price determined per their analysis for 1999 to be too low.

The above data shows that the $3.34/mmbtu "lower tier price" used by P&G is actually closer to the oil btu parity price. Based upon P&G's oil price forecast, an LNG price more representative of current and historical LNG pricing would be $3.72/mmbtu (112% of Btu parity $3.32/mmbtu). P&G uses the $3.34/mmbtu "lower tier price" as the base price for reporting the economics for an LNG project. The low sensitivity LNG price (pages VII-24 and VII-25) is 90% of their "lower tier price".

P&G (page VII-12) develops an "upper tier price" that they report in their report (page VII-13). The high sensitivity price (pages VII-24 and VII-25) is the average of the "lower" and "upper" tier price ($3.61/mmbtu).

The following ranks the respective LNG prices in $/mmbtu.

P&G low sensitivity price	$3.00
P&G lower tier price	$3.34
P&G economic report for LNG	**$3.34**
BTU parity with P&G oil price	$3.34
P&G higher sensitivity price	$3.61
Est. LNG price historical per Sumitomo	**$3.74**
P&G upper tier price	$3.89

Adjusting the P&G economic analysis to reflect the historical relationship between delivered LNG prices to Japan and JCC and using P&G value for JCC produces the following result:

	$/mmbtu	change
CIF Japan price	**3.72**	**+0.38**
Marine transport	0.65	
LNG plant operating costs	0.40	
LNG plant capital recovery costs	0.93	
Pipeline cost of service	1.14	
Producer netback	**0.60**	**+0.38**

2.) Marine transport

P&G assumes use of 137,500 CM tankers at $200 million each (page VII-20). P&G assumes one tanker per 1 MTA of LNG production. These assumptions are essentially the same as YPC.

3.) LNG plant operating costs

The P&G includes fuel in their plant operating costs. They give credit for colder ambient air in Alaska and reduce the fuel from 10% typical of an equatorial plant to 8% (Page VII-18). They did not go far enough however to reflect the benefits of high pressure low temperature feed to the plant. The following is a summary of fuel for various plants:

Typical equatorial	10-11%
P&G Alaska	8%
YPC with 2200 psi pipeline (Bechtel 1991)	6%
YPC with 2600 psi pipeline (KBR 2000)	4%

The YPC data is based upon heat and material balances provided by Air Products and Chemicals Inc. with minor engineering adjustments by Bechtel and Kellogg, Brown & Root. YPC's numbers are sound.

YPC designed the pipeline using our thermal-hydraulic simulation software and chose a high operating pressure that, for a number of reasons, minimized frost heave and thaw settlement concerns. Since we condition the gas on the North Slope there is no need to drop the pressure from the pipeline to liquefaction. Liquefaction efficiency and thus fuel vary with the inlet pressure to the plant. We took advantage of the higher pressure and optimized the LNG plant to improve the thermal efficiency.

I believe P&G used a 2200 psi pipeline design. They should reduce their fuel consumption to at least 6% in order to be consistent with their premises for the pipeline. YPC would use 4% fuel consistent with our design.

The premise used by virtually every party looking at a North Slope-sourced LNG project is that a single owner will purchase gas at the North Slope and sell LNG FOB Valdez. Incremental

economics regarding fuel consumption are thus based upon North Slope price. Typically, operating costs for the project are reported as non-fuel values with fuel costs are determined as the difference in BTUs sold versus purchased.

P&G says that fuel is a "major" expense. We don't have line item details of their operating costs. Assuming that "major" translates to "more than half", let's assume that fuel is 60% of the P&G operating costs of $0.40/mmbtu. Reducing the fuel from 8% to 6% would reduce the operating expense by $0.06/mmbtu [$0.40*60%*(8-6)/8].

Adjusting the P&G economic analysis to reflect 6% fuel produces the following result:

	$/mmbtu	change
CIF Japan price	**3.72**	**+0.38**
Marine transport	0.65	**0.0**
LNG plant operating costs	**0.34**	**-0.06**
LNG plant capital recovery costs	0.93	
Pipeline cost of service	1.14	
Producer netback	**0.66**	**+0.44**

4.) LNG plant capital recovery costs

In the year 2000, YPC developed capital costs for the LNG plant and marine terminal based upon our new high pressure design. The excavation and plot plan were developed for YPC by Michael Baker, Jr. The heat and material balances were developed by APCI. CBI provided a design and cost for the LNG tanks. Moffatt & Nichol developed the design and cost estimate for all marine facilities. KBR developed the design of the liquefaction plant (based upon the APCI balances), utilities and other attendant facilities based upon their database of costs for other base load LNG facilities. KBR rolled all of the costs together in a turnkey estimate of a 2 train (9.2 MTA), 3 train (13.8 MTA) and 4 train (18.4 MTA) facility. The KBR estimate includes contingency for a 75% probability of cost under run. YPC added costs for owner management of the project.

The cost of a YPC's 9.2 MTA and 13.8 MTA liquefaction plant and marine terminal scenarios in US2000$ are $2.3 and $3.1 billion respectively. P&G's estimate for a 14 MTA facility is $5.3 billion.

YPC estimate for a 14 MTA facility is 42% less than P&G's estimate. Again it must be noted that P&G's design is based upon a fuel consumption twice that of YPC's (8% vs. 4%). One would expect the P&G design to cost more since there is twice as much fuel consuming equipment.

The following reflects a somewhat arbitrary adjustment of the P&G capital costs for the LNG plant referenced to YPC's costs using a ratio of 6% fuel to 4% fuel (42% * (1-0.33) = 28% less):

	$/mmbtu	change
CIF Japan price	**3.72**	**+0.38**
Marine transport	0.65	**0.0**
LNG plant operating costs	**0.34**	**-0.06**
LNG plant capital recovery costs	**0.67**	**-0.26**
Pipeline cost of service	1.14	
Producer netback	**0.92**	**+0.70**

5.) Pipeline cost of service

On page V-21, the following COS in $/mmbtu are reported for a pipeline from Prudhoe to the south shore (Valdez):

BSCFD	COS
0.8	1.27
1.0	1.14
1.6	0.84
2.0	0.76
3.0	0.72

The pipeline cost of service reported in the economics is for 1.0 BSCFD, however, the LNG plant COS reported is for 2.0 BSCFD (approximately 14 MTA). P&G notes that the flow ramps up from 1 to 2 BSCFD. Using the COS for a 1 BSCFD scenario for a project ramping to 2 BSCFD is very conservative.

P&G does not have a pipeline COS for a ramp-up scenario. Perhaps some value between the COS for a 1 and 2 BSCFD scenario should be used in the economics. The following reflect the P&G economics adjusted (somewhat arbitrarily) for a pipeline COS ramped from 1 to 2 BSCFD [0.95 = (1.14 + 0.76)/2]:

	$/mmbtu	change
CIF Japan price	**3.72**	**+0.38**
Marine transport	0.65	0.0
LNG plant operating costs	**0.34**	**-0.06**
LNG plant capital recovery costs	**0.67**	**-0.26**
Pipeline cost of service	**0.95**	**-0.19**
Producer netback	**1.11**	**+0.89**

6.) Alaska income tax

P&G assumes a 9.4% income tax rate for Alaska. The oil companies use worldwide accounting that reduces their effective Alaska income tax rate to about 3.6% in 1999. Assuming international oil company ownership of all or part of the facilities, the tax of an Alaskan project appears overstated by 5.8%. Obviously, this would not apply to a Canadian project.

B. Summary on economics for the LNG alternative

P&G's approach was to apply a consistent set of criteria to various gas project options to generate comparative economics. It appears that their economic comparison was done to assess the relative merits of the project as opposed to endorsing the viability of any one project.

The above analysis shows that combining the P&G analytical approach with YPC cost estimates and view of market pricing would result in a LNG project netback price in excess of **$1.00/mmbtu**. ***This netback is higher than any of the pipeline options to the lower 48 states***. This value exceeds the value YPC considers as a probable wellhead value and is somewhat suspect.

The assumptions used by P&G differ significantly fror those used by YPC for the TAGS project. It is possible for people to have different opi..ons. P&G should consider reviewing their assumptions regarding LNG for the following reasons:

1 – Their capital cost estimate for the LNG plant and marine terminal is significantly larger than estimates produced by the licensor of the process technology used in over 80% of the worldwide base load capacity (APCI) in conjunction with an EPC firm that designs and builds LNG plants (KBR).

2 – P&G did not complete a cost of service for a pipeline ramping up to a design volume of 2 BSCFD (14 MTA). Use of the COS for a 1 BSCFD is a very conservative assumption. Any gas project from Alaska, whether overland or LNG, will have to ramp-up to the market entry volume within 2 years. P&G assumes quick or instantaneous ramp-up of the overland pipeline options (i.e., 4 BSCFD scenarios). On page II-1 P&G acknowledges that unless the LNG project is "piggy-backed" with another project, the LNG project must be massive in order to reduce the unit gas transportation costs. Uniform application of P&G's premises does not support use of a COS for a 1 BSCFD line for the LNG option.

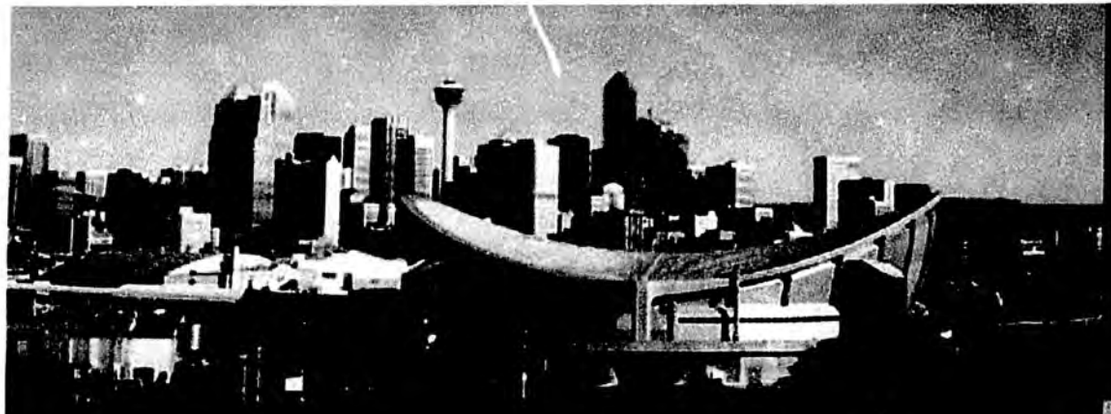
3 – P&G's use of an LNG price at BTU parity with oil is not supported by historical data regarding LNG imported to Japan. Recognizing that people can differ regarding speculating about the future, it still seems reasonable to set the base economics at the historical condition (i.e., 112% of BTU parity with oil) then complete a sensitivity analyses above and below the base. P&G's price in the higher sensitivity case is less than the historical base condition experienced in the LNG market. It seems overly pessimistic to run all economics below the historical average condition especially since worldwide gas demand appears to be dramatically increasing (i.e., low cost of gas turbine combined cycle plants, quick installation time of these plants and environmental benefits regarding energy produced per molecule of CO2 released).

C. Piggy-backing LNG with GTL

P&G recently issued work regarding piggy-backing an LNG project with a GTL project located on the south shore of Alaska. Unfortunately, this scenario is not included in their report of Alaskan gas pipeline options. Piggy-backing LNG with GTL will not only reduce the unit transportation costs, but will increase the throughput per unit of installed capital for the LNG. The liquefaction plant can be designed for an extended end flash with the flash gas going to the feed of the GTL plant. This will reduce the specific horsepower (Hp per unit of LNG produced) and increase the efficiency of use of capital expenditure.

D. Asia Pacific LNG Supply and Demand

P&G shows that there is sufficient incremental demand for a 14 MTA LNG project from Alaska. However, the P&G values for incremental demand are less than those of YPC, Standard & Poors DRI, and Tokyo Gas.



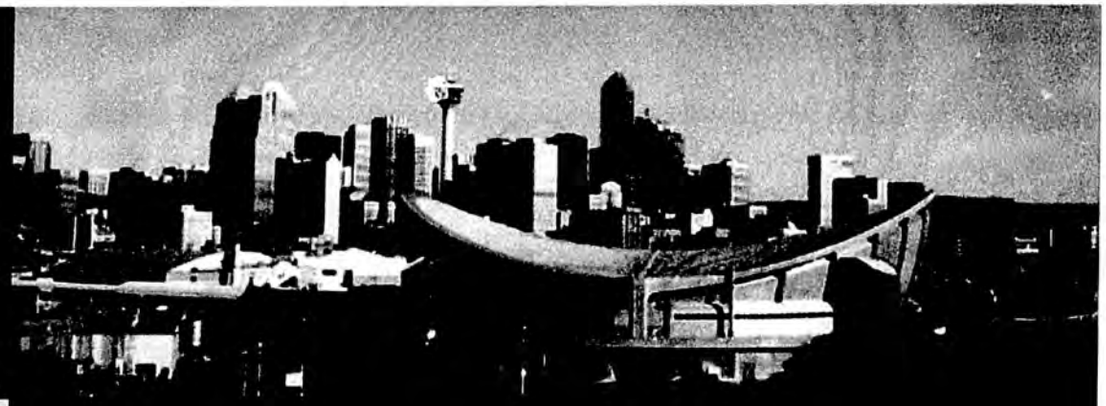
Duke Energy

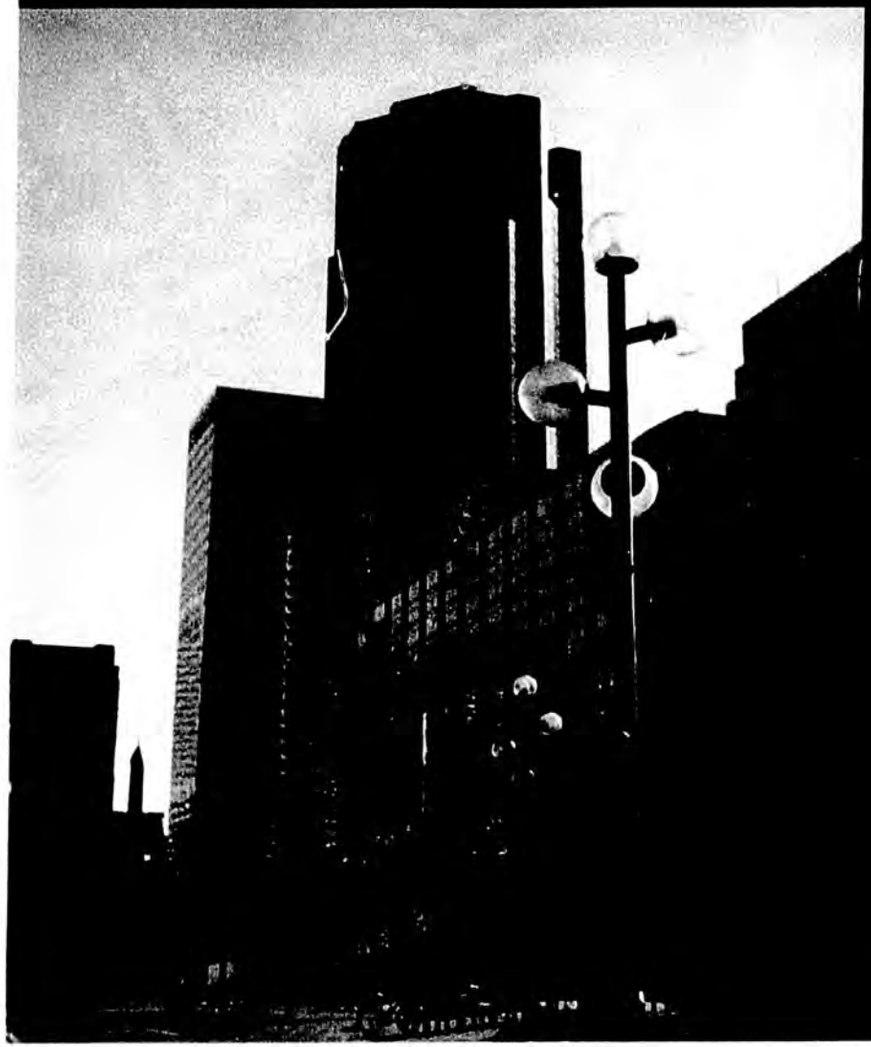
Northern Development



Spring 2002

Duke Energy





Duke Energy Gas Transmission

Brad Reese

Sr. VP Northern Development and Co-CEO Foothills Pipe Lines Ltd.

Duke Energy Acquisition of Westcoast Energy

Duke Energy

① Who is Duke Energy?

② Why did we acquire Westcoast?

③ What are our plans?

④ What are our capabilities?

⑤ What does this mean for the energy industry and Northern Development?

J204-0136

Duke Energy

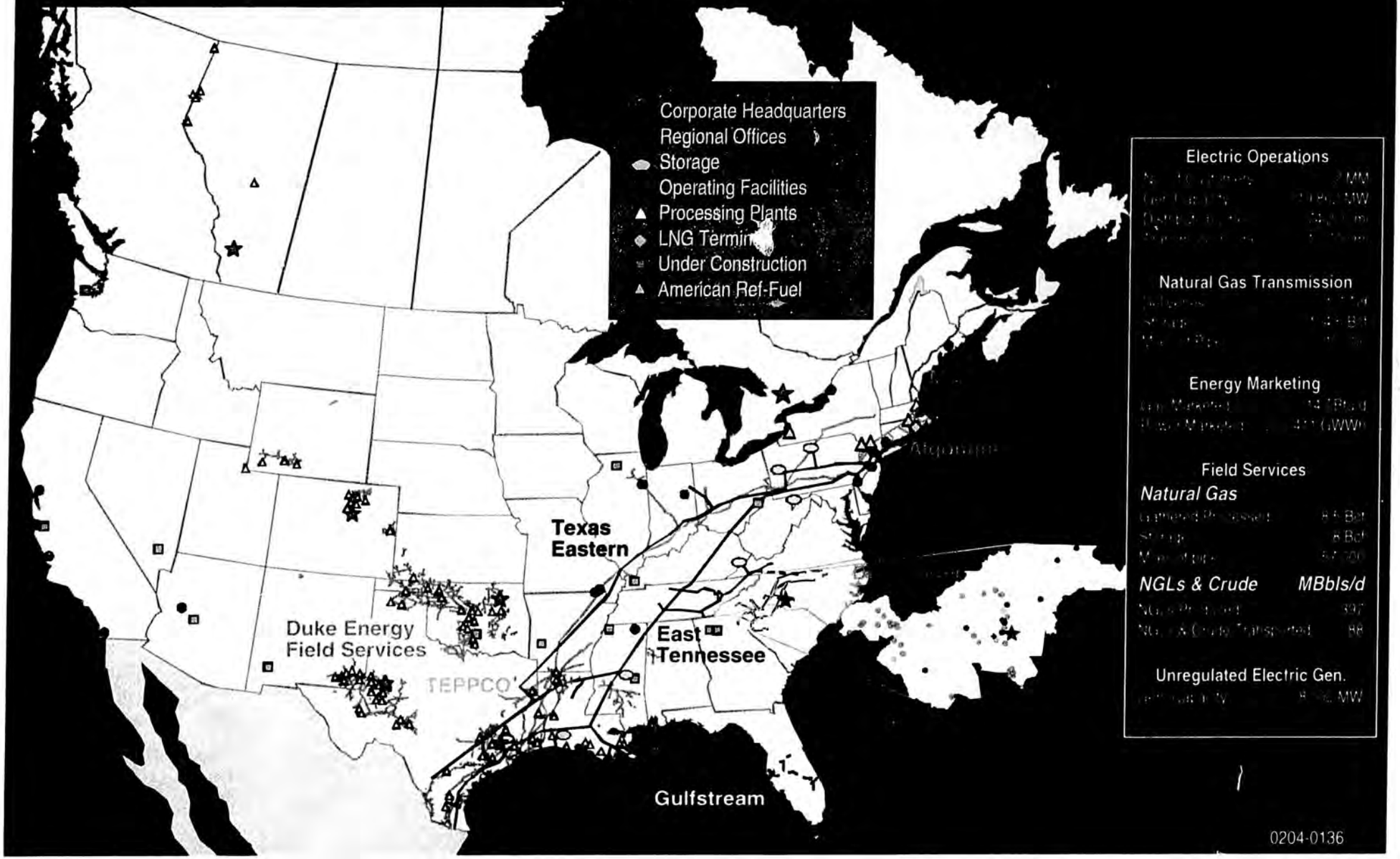
Who is Duke Energy?

- Named the nation's most admired company in the Energy Sector by Fortune Magazine 2001
- #14 on Fortune's 'Top 100 List in 2001
- Revenues of US $59 billion / earnings US $4.3 billion (2001 year end)
- 23,000 employees worldwide
- Assets of US $49 billion
- #2 gas marketer in U.S.
- #3 power marketer in U.S.
- 30,000 megawatts of generation

0204-0136

Current Duke Energy North America Operations

Duke Energy

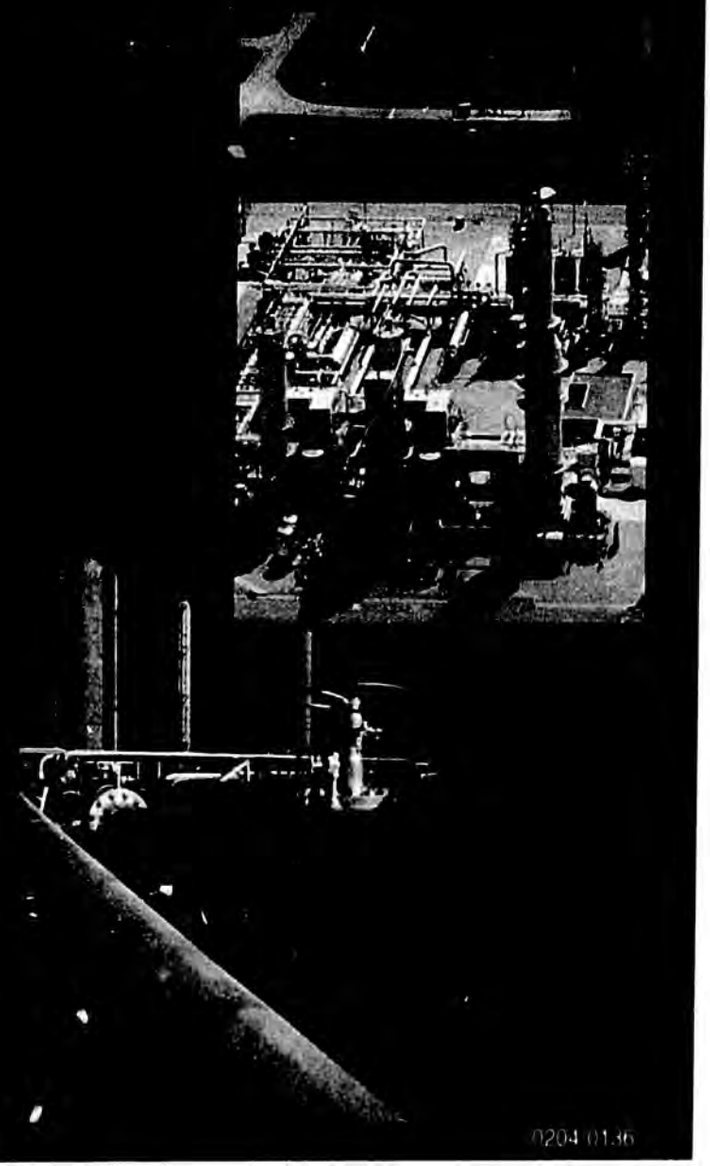


Duke Energy

Duke Energy Gas Transmission

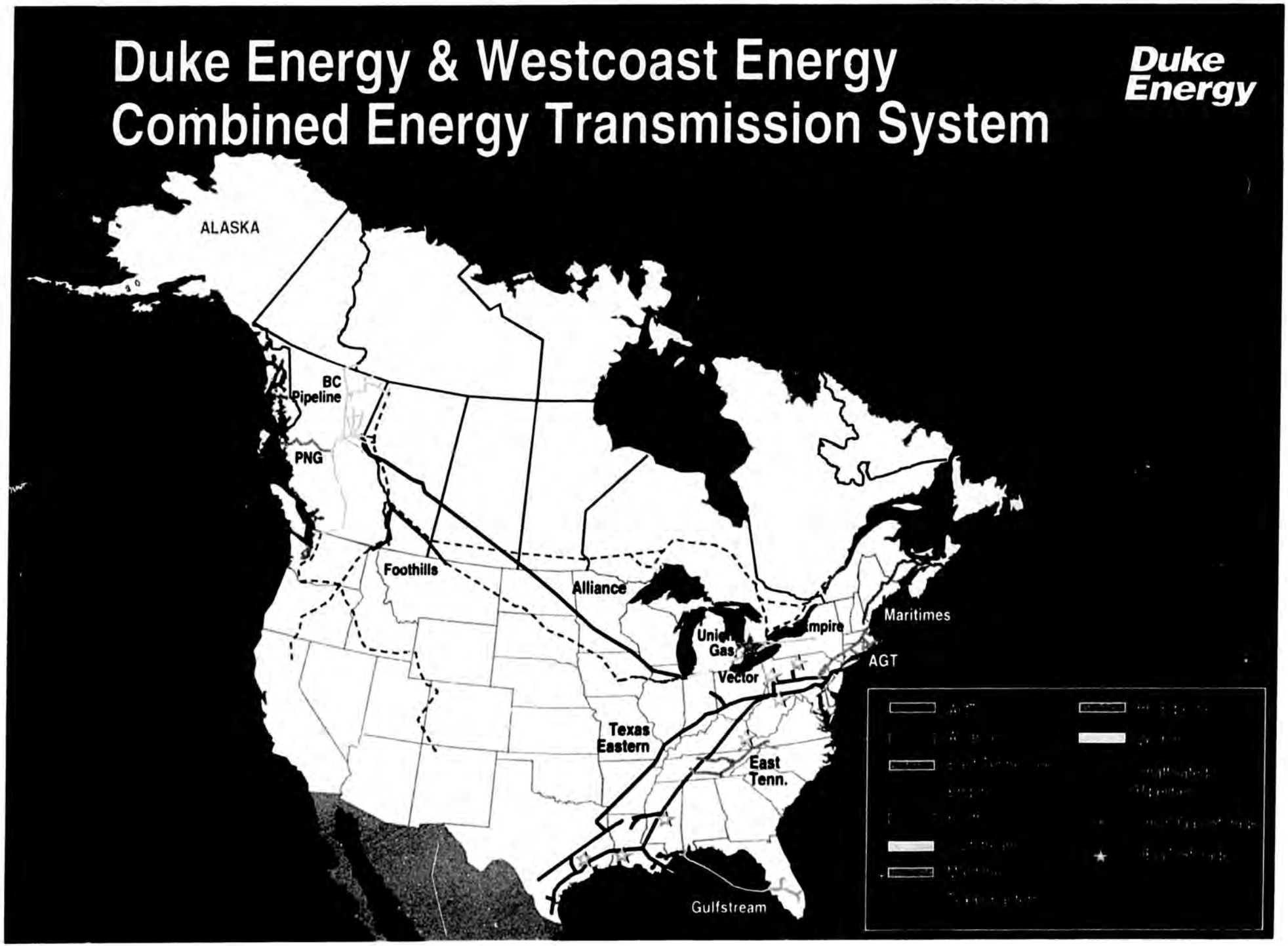
Gas Transmission —

Connecting supply and high-growth markets



Duke Energy & Westcoast Energy
Combined Energy Transmission System

Duke Energy



Duke Energy Acquisition of Westcoast Energy

Duke Energy

1. Who is Duke Energy?
2. **Why did we acquire Westcoast?**
3. What are our plans?
4. What are our capabilities?
5. What does this mean for the energy industry and Northern Development?

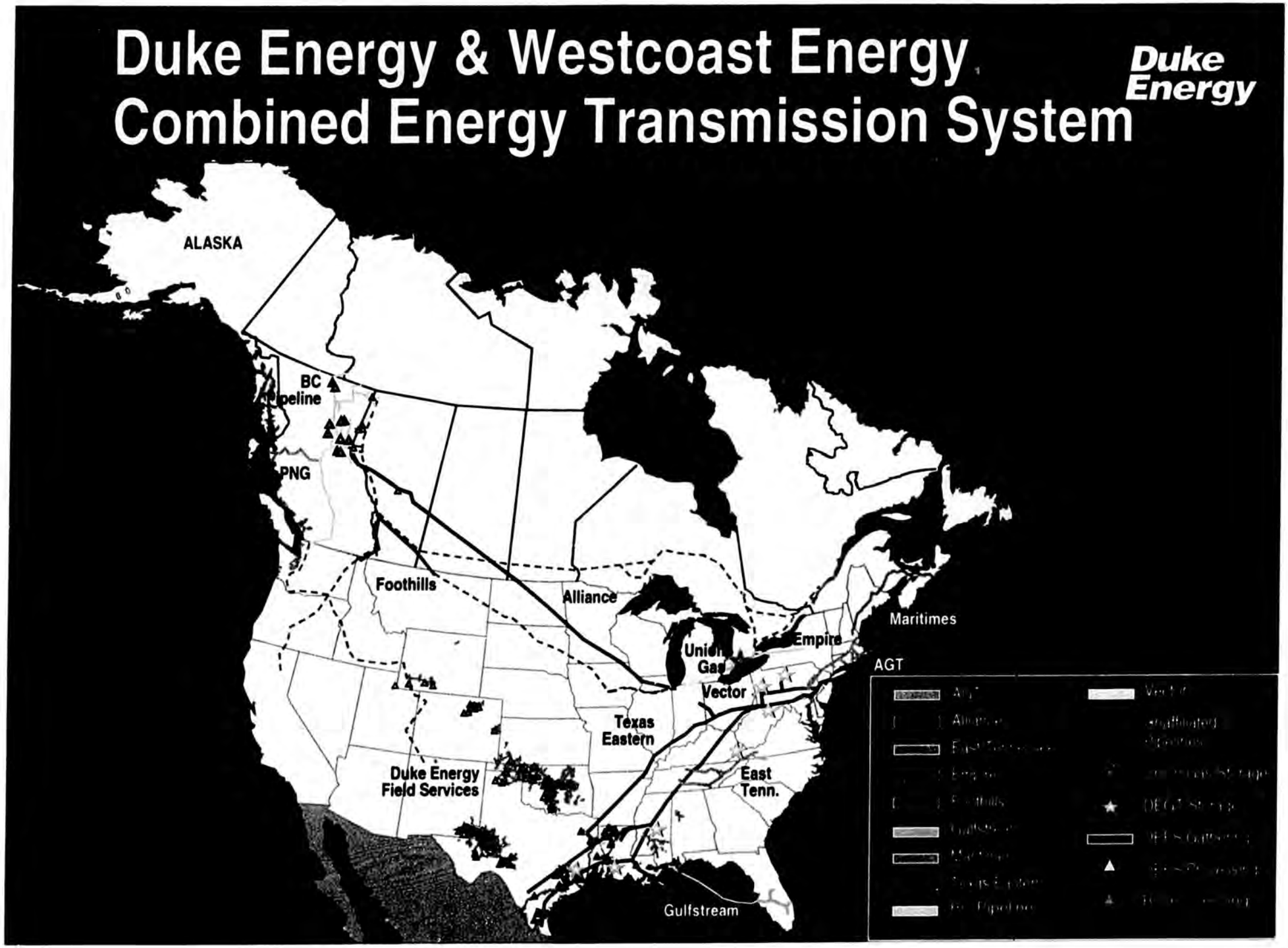
Duke Energy

Why Westcoast Energy?

- A major step (US $8.5 billion) in Duke Energy's growth and evolution
- An industry leader in North America
- A company we respected and knew well
- Excellent operational and strategic fit
- Combination realizes growth potential, synergies and cost savings
- Strategic supply position

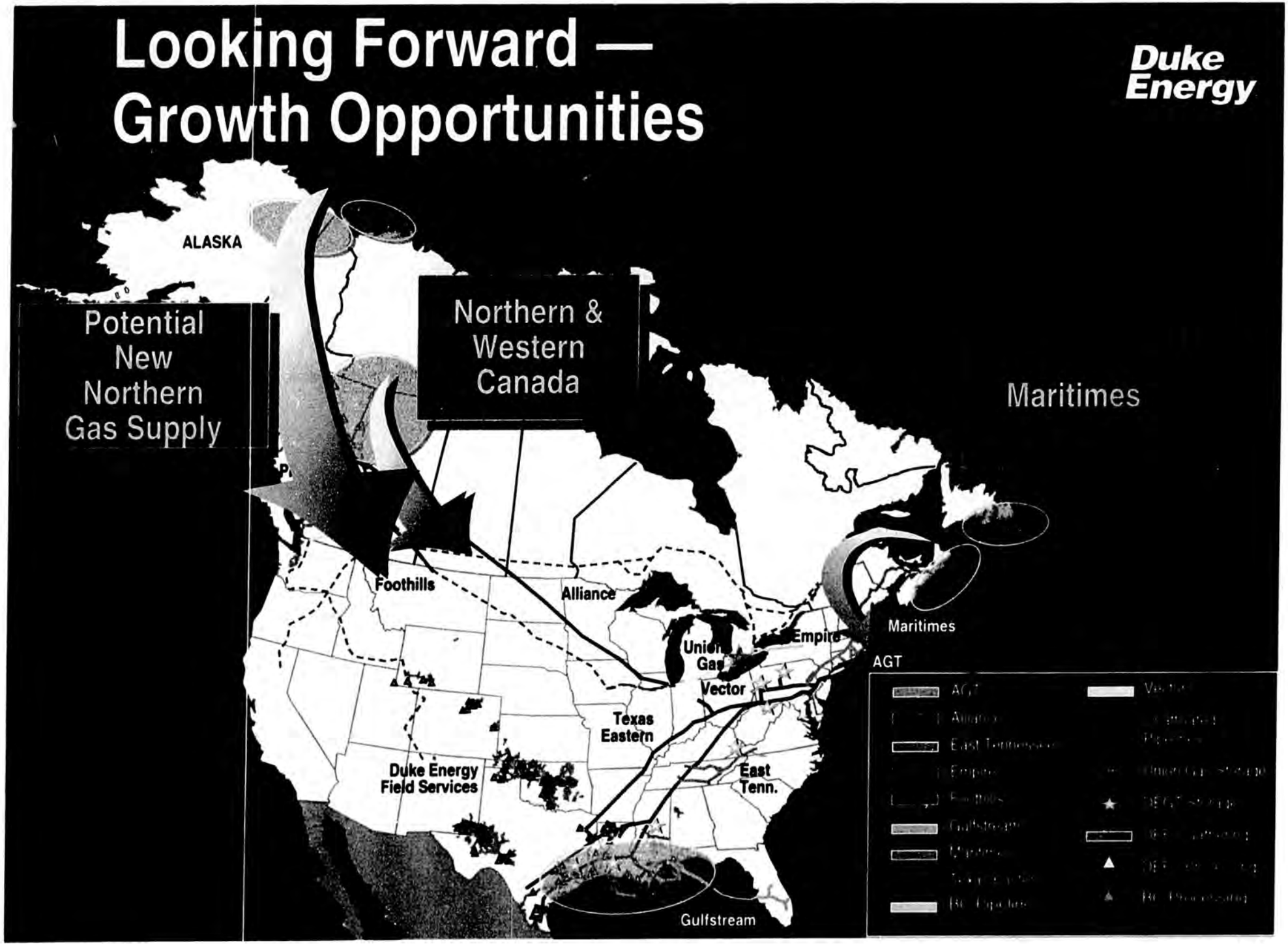
Duke Energy & Westcoast Energy Combined Energy Transmission System

Duke Energy



Looking Forward — Growth Opportunities

Duke Energy



Duke Energy Acquisition of Westcoast Energy

Duke Energy

1. Who is Duke Energy?
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5. What does this mean for the energy industry and Northern Development?

Duke Energy

What Are Our Plans?

- Extend North American integrated network of natural gas infrastructure
- Increase the portfolio of growth opportunities
- Connect key supply sources and growing markets
- Add storage and transportation assets at a growing Eastern supply hub
- Pursue significant opportunities to leverage Duke Energy's merchant expertise

0204-0136

Duke Energy Acquisition of Westcoast Energy

Duke Energy

1. Who is Duke Energy?
2. Why did we acquire Westcoast?
3. What are our plans?
4. **What are our capabilities?**
5. What does this mean for the energy industry and Northern Development?

Maritimes & Northeast Pipeline Project

Duke Energy

New 650-mile greenfield pipeline serving first offshore Nova Scotia commercial gas development commissioned in December 1999

Duke Energy's U.S. segment crosses 1,400 wetlands, 400 water bodies and 4 major rivers with no environmental citations, violations or penalties

M&NE pipeline coordinated NEB and FERC process, successfully acquired ROW with minimal landowner issues, and worked cooperatively with First Nations

FERC requested DEGT make presentations at its Facility Planning Seminars and used model as Best Practice for pre-filing procedures and construction

Committed to Environmental and Social Balance

Duke Energy

Successful consultation with First Nations

Legacy of aboriginal economic development reaching beyond the project

8 different stream crossing techniques used

Construction scheduled with no interruptions to wading bird habitats and deer wintering areas



0204-0136

Committed to Environmental and Social Balance

Duke Energy

No major injuries or OSHA violations – exemplary safety record

Significant public issues and constituent concerns handled timely, professionally and satisfactory to agencies and landowners

Gained public confidence through trust and respect for the environment and safety first for all!



0204-0136

10 Keys to Success

Duke Energy

- Maximize use of existing corridors
- Pro-active early involvement with key stakeholders
- Commitment to deliver on promises
- Maintain communications with all stakeholders
- Resolve issues quickly
- Employ partnering / collaborative relationship with agencies
- Utilize local knowledge and expertise
- Give back to the community
- Manage your contractors
- Treat each project like you expect to come back soon and build again





0204-0136

Duke Energy Acquisition of Westcoast Energy

Duke Energy

1. Who is Duke Energy?
2. Why did we acquire Westcoast?
3. What are our plans?
4. What are our capabilities?
5. **What does this mean for the energy industry and Northern Development?**

Duke Energy's Potential Contribution to Northern Development Efforts

Duke Energy

- Advanced pipeline development capabilities (2200 miles of new pipeline in U.S., Maritimes-Canada, & Australia)
- Electric generation development and gas demand in U.S.; plus capacity on various interstate pipelines including PGT and Alliance
- Effective management of commercial, regulatory and field operations
- Engineering and construction success in complex, multi-jurisdictional, environmentally sensitive projects
- Facilitate alignment with producers, pipeline partners, government and communities





What Does This Mean for the Energy Industry in Canada

Duke Energy

GROWTH

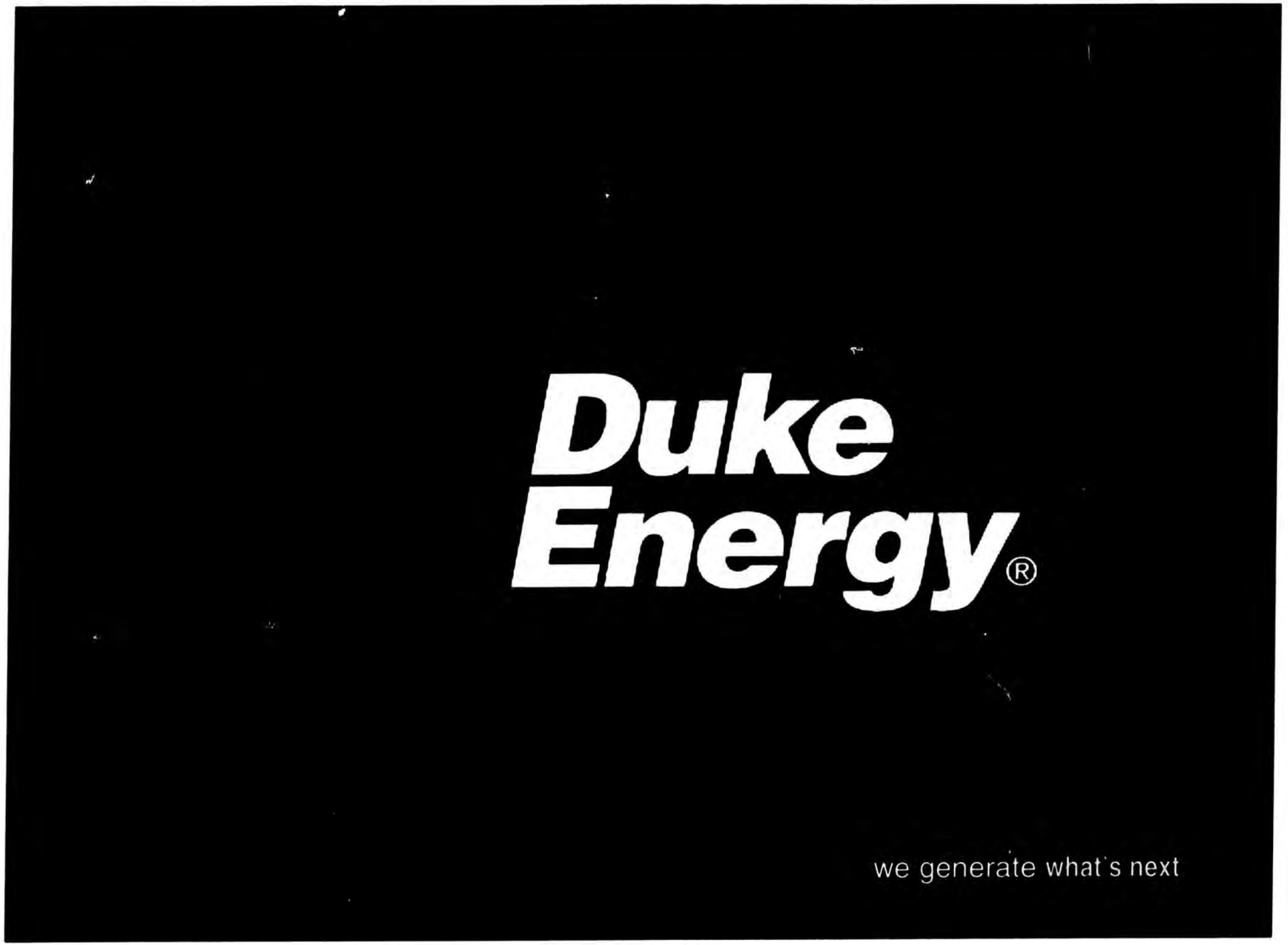
Balance sheet strength and capital expenditure capacity

Future investment and timely connection of new supply sources

- East Coast
- Northeast B.C.
- Southern NWT & Yukon
- Alaska North Slope
- Mackenzie Delta

North American best practices

Efficiency, cost control and customer service


Duke
Energy®
we generate what's next

SCOMM

129:2

Sen. Ted Stevens Speaks to Committee on Gas Pipeline, ANWR

(FAIRBANKS) - The Joint Committee on Natural Gas Pipelines heard testimony Wednesday on some of the issues in bringing Alaska's natural gas to market, including regulatory jurisdiction and proposed federal legislation.

Sen. Ted Stevens (R-Alaska) was the final presenter on Wednesday, speaking to the committee during the period allowed for public testimony. Stevens congratulated Rep. Don Young (R-Alaska) on House passage of the Energy Bill, which includes a provision to allow oil and gas exploration on the coastal plain of the Arctic National Wildlife Refuge, and commended the efforts of Sen. Frank Murkowski (R-Alaska) to pass the bill through the Senate.

Stevens also told the committee that he continues to believe the highway route is the best route for a natural gas pipeline as it allows the possibility of both in-state use and outside marketing for Alaska's gas. He mentioned legislation proposed by BP Exploration, ExxonMobil and Phillips, saying that at this time he is not happy with the bill and that Senator Murkowski's office is currently reviewing it.

Following the scheduled testimony, the committee held a brief meeting and discussed the logistics of the protocol trip to western Canada scheduled for Aug. 20-24. Committee delegates will meet with national and provincial/territorial government representatives in British Columbia, Alberta, Yukon and Northwest Territories.

The committee announced that it will hold hearings in Anchorage on September 19 to address federal natural gas legislation and in Kenai on Oct. 2 - 3 to hear updates on natural gas pipeline issues and Cook Inlet natural gas production and use.

For Immediate Release: Aug. 14, 2001
Contact: Sen. John Torgerson, (907) 260-3041

Committee Hears of Progress on Pipeline
State and Federal Agencies Provide Updates on Pipeline Issues

(Fairbanks) – On Tuesday the Joint Committee on Natural Gas Pipelines heard from state representatives on some of the legal and practical aspects surrounding construction of a natural gas pipeline and future gas sales.

Department of Revenue Commissioner Wilson Condon spoke to the committee on the status of a report to the Legislature regarding state ownership or involvement in a pipeline, and introduced Bill Gardner with Petrie Perkman, which has been hired to help prepare the report. Petrie Perkman is an investment and advisory firm that focuses on the oil and gas industry, providing information and analysis to private groups and governments around the world. Gardner outlined the process that the firm will take to make their final evaluation, and described some of the projects that they are currently working on for their clients.

Cammy Taylor and Julie Heusser, two of the three commissioners of the Alaska Oil and Gas Conservation Commission (AOGCC), provided information on the conservation orders that would apply to North Slope gas sales, as well as the conclusions of a study on the effects of gas production on oil field life. They explained that some of the conservation rules are based on outdated information but can not be revised until AOGCC obtains current technical data. Currently Conservation Rule Nine limits the production of natural gas from the Prudhoe unit to 2.7 billion cubic feet a day.

Jack Griffin, head of the Oil and Gas Division of the Department of Law, addressed legal questions from the committee regarding overlifting and underlifting by producers who hold interest in production fields. Overlifting and underlifting describes when a producer takes more or less than its allocated share from a field during a specific period of time. Griffin discussed how current leases would affect natural gas production as well as Prudhoe Bay Unit amendments. The committee also questioned Grifffin about the procedures for terminating leases if producers do not produce and market the gas.

State Pipeline Coordinator Bill Britt updated the committee on the activities of the Gas Pipeline Office has engaged in since it last reported to the committee in July. The office has received signed memorandums of understanding from Foothills Pipe Lines and the oil and gas producers agreeing to reimburse the state for any costs incurred in preparing for and evaluating right-of-way permits for a gas pipeline. The office has held meetings with El Paso Gas, Williams Petroleum and Anadarko, and is establishing relationships with all of the federal agencies that would be involved in the construction of a pipeline.

8/14-15

ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

Official Business

Senator John Torgerson, Chair
Senator Rick Halford
Senator Pete Kelly
Senator Johnny Ellis

Representative Joe Green, Vice-Chair
Representative Brian Porter
Representative Scott Ogan
Representative John Davies

AGENDA

FAIRBANKS NORTH STAR BOROUGH ASSEMBLY CHAMBERS
809 PIONEER ROAD

AUGUST 14TH AND 15TH, 2001
Fairbanks, Alaska

Tuesday, August 14

1:30 p.m. - 1:35 p.m. Call to Order and Introductions

1:35 p.m. - 2:30 p.m. Department of Revenue

SB 158 directs the Department of Revenue to analyze the state's role in financing a natural gas pipeline. Commissioner Condon and Bill Gardner with Petrie Perkman will present the Committee with an update on the status of this report.

2:30 p.m. - 3:30 p.m. Alaska Oil and Gas Conservation Commission

Commissioner Cammy Oechsli Taylor will discuss various issues related to the role of the AOGCC in the development and production of Alaska North Slope natural gas, i.e. current status of Conservation Orders, status of permit discussions with Prudhoe Bay lessees, findings of AOGCC consultant report to study effects of gas production on oil recovery, and funding for the report.

Session: January - May
State Capitol, #427
Juneau, AK 99801
Phone: 907-465-2828
Fax: 907-465-4779

Interim: May - December
35477 Kenai Spur Hwy., Suite 101A
Soldotna, AK 99669
Phone: 907-260-3041
Fax: 907-260-3044

3:30 p.m. - 4:15 p.m. Department of Law

Jack Griffin, Assistant Attorney General, will address legal questions regarding overlifting, underlifting, lease termination, and Prudhoe Bay Unit amendments.

4:15 p.m. - 5:00 p.m. Legislative Legal Counsel

Jack Chenoweth, Legislative Legal Counsel, will address legal questions regarding overlifting, underlifting, lease termination, and Prudhoe Bay Unit amendments.

5:00 p.m. - 5:30 p.m. Joint Pipeline Office

Bill Britt, State Pipeline Coordinator, will present an update on JPO activities and the status of MOUs with producer groups.

5:30 p.m. - 6:00 p.m. Public Testimony (limit 3 minutes per speaker)

6:00 p.m. - 7:00 p.m. Reception in the Fairbanks News Miner Building sponsored by the Fairbanks North Star Borough and the Fairbanks Chamber of Commerce

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Wednesday, August 15

9:00 a.m. - 9:05 a.m. Call to Order and Introductions

9:05 a.m. - 9:30 a.m. Congressional Report

Congressional delegation staff will update the Committee on Congressional action regarding energy policy.

Dyer, Ellis & Joseph, a Washington D.C. law firm under contract with the Legislature to monitor federal energy legislation, will also update the Committee on Congressional activity.

9:30 a.m. - 10:00 a.m. John Katz, Director of State/Federal Relations and Special Counsel to the Governor

Update on Canadian political actions regarding Alaska's natural gas, in particular, their reaction to the ban imposed by the U.S. Congress on the over-the-top route and Prime Minister Chretien's comments during the G-8 summit regarding Alaska's natural gas.

10:00 a.m. - 10:30 a.m. Robert Loeffler, Attorney with Morrison & Forrester

Robert Loeffler will comment on general FERC issues including state tariffs and prices, mid-route delivery points, regulation of an all-Alaska pipeline, regulation of common carriers, and general terms of regulations under NGA or ANGTA.

10:30 a.m. - 12:00 p.m. Regulatory Agencies

a) 10:30 a.m. - 11:00 a.m. Federal Energy Regulatory Commission (by teleconference or written testimony)
b) 11:00 a.m. - 12:00 p.m. Nan Thompson, Commissioner and Chair, Regulatory Commission of Alaska

At the last meeting of the Joint Natural Gas Pipeline Committee, there were a lot of unanswered questions and confusion concerning the authority of FERC and our Regulatory Commission of Alaska. These issues include state tariffs and prices, mid-route delivery points, regulation of an all-Alaskan pipeline, regulation of common carriers, and general terms of regulations under NGA or ANGTA. FERC and RCA will discuss their respective jurisdictions over a natural gas pipeline, upstream access to the pipeline, and downstream access to a pipeline.

12:00 p.m. - 1:00 p.m. Lunch Break

1:00 p.m. - 1:30 p.m. Alaska Highway Natural Gas Policy Council

An update on recent activities conducted by the Governor's Council.

1:30 p.m. - 2:30 p.m. Department of Revenue, tax issues

Commissioner Condon will present information regarding Alaska's gas royalty and tax system.
Update on market conditions by Cambridge Energy.

2:30 p.m. – 2:45 p.m. **Alaska Natural Gas to Liquids Company**

Richard Peterson, President and CEO, will give an overview of his company's natural gas to liquids project.

2:45 p.m. – 3:45 p.m. **Alaska Gasline Port Authority**

The port authority was created under Alaska statutes allowing separate port authorities to be formed by municipal governments. Voters in the City of Valdez, Fairbanks North Star Borough and North Slope Borough approved its creation in October 1999. The purposes of the port authority include creating jobs, providing gas to Alaskan communities and helping stabilize the state economy by helping commercialize stranded North Slope gas. The port authority plans to use tax-exempt public debt financing for a portion of the project to lower costs and dramatically increase the economic viability of a large gas project, and maximize benefits to both Alaska and the producer companies. Bill Walker, general counsel for the port authority, will describe the port authority and its activities to the committee.

3:45 p.m. – 4:30 p.m. **Producer Groups**

Representatives from the producer groups will provide an analysis of proposed federal legislation submitted to Alaska's Congressional Delegation and a general discussion on advalorem tax.

4:30 p.m. – 5:00 p.m. **Foothills Pipe Lines**

Representatives from Foothills Pipe Lines will provide an analysis of proposed federal legislation submitted by the producer groups to Alaska's Congressional Delegation and an update on the withdrawn partner issue.

5:00 p.m. – 5:15 p.m. **Joint Committee on Natural Gas Pipelines meeting (agenda to follow)**

5:15 p.m. – 5:30 p.m. **Additional Testimony by Invitation of the Chair**

5:30 p.m. – 6:00 p.m. **Public Testimony (limit to 3 minutes per speaker)**

SCOMM

129:3

ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

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Senator Rick Halford
Senator Pete Kelly
Senator Johnny Ellis

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Representative Brian Porter
Representative Scott Ogan
Representative John Davies

NOTES ON WESTERN CANADA MISSION
Joint Natural Gas Pipeline Committee
August 19 – 24, 2001

Alaska Delegation Membership:

Sen. Torgerson, Chair
Sen. Ellis
Sen. Olson
Rep. Green, V. Chair
Rep. Chenault
Rep. Davies
Rep. Fate
Rep. Joule
Rep. Ogan

Mr. Charles Brower, N. Slope Borough
Mr. Jim Mendenhall, ASRC
Mr. Jack Laasch, Natchiq, Inc.
Mr. Bill Stamps, PEAK

Ms. Ronda Thompson, Staff
Mr. David Gray, Staff

WHITEHORSE, YUKON TERRITORY, Monday, Aug. 19

11:30 – 1:00 pm, Meeting with Yukon Territory government officials in the airport conference room.

Yukon Delegation:

Hon. Pat Duncan, Premier
Hon. Scott Kent, MLA, Minister of Development & Econ. Expansion
Mr. Greg Komaromi, Director of Oil and Gas
?
?

Session: January – May
State Capitol, #427
Juneau, AK 99801
Phone: 907-465-2828
Fax: 907-465-4779

Interim: May – December
35477 Kenai Spur Hwy., Suite 101A
Soldotna, AK 99669
Phone: 907-260-3041
Fax: 907-260-3044

Premier Duncan reported on the recent meeting of the Western Governors and Premiers Conference and energy discussions with U.S Secretary of Interior Gale Norton. Said there is another meeting of the Yukon, Alberta, BC and Alaska governments on issues of common concern scheduled for Aug. 30 (subsequently cancelled). The premier also announced that the next Western Govs and Premiers Conference is in Dawson City, June 4 – 6, 2002.

Sen. Torgerson related the activities and efforts of the committee. Spoke to the reasons that the over-the-top route to the Mackenzie was unacceptable, listing Alaskan development opportunities and in-state energy needs.

Torgerson observed that the Alaska Hwy route would pass through at least four governmental jurisdictions, each with their own particular desires, needs and responsibilities. He stated that there needed to be some forum where all participants could exchange information and address issues of mutual concern. The exchange of information was even more pressing because of the rapid approach of decisions and commitments. He noted recent proposed legislation by the producers in Washington, D.C. Thus, a closer interaction between the different governments would benefit all parties and ultimately the project itself. This was the basis for inviting Yukon, NWT, Alberta, and BC to establish and international gas pipeline committee with Alaska.

Premier Duncan welcomed the invitation and thanked the delegation for taking the initiative. She agreed that there was a need for closer cooperation and coordination between the governments and offered to advance the proposal with her Western Canada colleagues. She proposed that the first meeting of the international committee by held in Whitehorse. She stated that Minister Kent would be the principal lead for the Yukon government.

Other topics discussed: ANWR and NWT's Mackenzie delta developments.

Meeting ended at 1:05. Premier Duncan and Sen. Torgerson held a joint press conference. Individual members of the delegation talked with Mr. Alan Edzerza and Rick OBrian of the Kaska Tribal Council to hear the status of their land claims and pipeline involvement.

Left for Yellowknife at about 2:00 pm.

YELLOWKNIFE, NORTHWEST TERRITORIES, Tuesday, Aug. 21.

9:00 am – 11:00 am Briefing on the NWT diamond industry and tour of the Arslanian processing facility. Since the discovery of diamonds in NWT in 1991, one mine is developed and operating, another will start production in 2003 (at an investment of $1.3 billion CA), and two others are in the beginning stages of development. It is estimated that Canada with supply 12% of the world's diamond production by 2005. NWT retains a percentage of the diamonds mined

and have contracted a diamond manufacturing facility (cut and polish) in Yellowknife. Imported Armenian artisans are employed to produce jewelry grade gemstones and train Canadian apprentices.

1:30 – 4:30 pm Meeting with NWT government officials in the Legislative Assembly building.

NWT delegation:

Hon. Joe Handley, Minister of Finance, Minister of Resources, Wildlife and Economic Development
Mr. John Bayly, Principal Secretary to the Executive
Mr. Doug Dallman, Dep. Commissioner
Mr. Cal Brackman, Oil and Gas
Mr. Scott Ray, Resource Economist
Mr. Ross Bower, NWT Housing Corporation
Mr. Doug Cardinal, First Nations representative

After exchange of greetings and introductions, Sen. Torgerson noted Premier Kakfwi's letter declining to join an international committee because of actions in the Ak. Legislature and US House of Representatives against "alternative pipeline routes." Torgerson said he thought this meeting important to preserve a good neighbor policy, to explain why Alaskans are so opposed to the over-the-top route, and to ask for reconsideration to joining the committee because there are other issues of Arctic gas pipeline developments that necessarily involve NWT.

Sen. Torgerson went on to list development opportunities and in-state energy needs that Alaskans were hopeful about. He noted that the state is the owner of 12 ½ percent of the gas.

Sen. Olson, Rep. Joule, and Mr. Brower explained how important whales and whaling was to the Inupiat people of the North Slope and that they were adamantly opposed to any activities that would disturb or threaten the whales. They also noted that North Slope people share a long history with people of NWT and there are many extended family connections.

Rep. Green presented the limited life of current gas reserves for Anchorage and the Southcentral region energy needs. The gas pipeline project offers the possibility to secure the energy future for the state's largest population. Rep. Davies said the legislature's action against the over-the-top route was not against NWT and Mackenzie development per se, but rather the desire for the economic benefits of value added processing of the resource in state. He noted that this was no different then the territory's laudable efforts to establish a diamond manufacturing industry in the region and promote a "Canadian Diamond" market. Rep. Chenault observed that if a proposed development of Mackenzie delta featured an over-the-top route to Prudhoe and down to Valdez, NWT

would face a similar situation as Alaska and would be expected to act the same. Other representatives made comments in the same vein.

Minister Handley responded that it was always clear that the route was Alaska's decision. All points made on value added, the environment, and animal protections are shared by them. But their primary focus is how to get Canadian gas to market. If over-the-top was the cheapest way, then there was an argument that everyone could benefit. They felt that Alaska's action in prohibiting this route was premature and without consultation. Now, they will continue to work with producers and aboriginal groups to advance a Mackenzie pipeline project.

Handley went on to explain economic activities occurring in NWT and the potential for strengthening ties and increased partnership with Alaska. NWT economy is in great shape. Mining, oil and gas field development, transportation services from the Mackenzie, Arctic housing sales, tourism are some of the areas to work together on.
Suggested the NWT may be open to a broader international committee on trade.

Mr. Doug Cardinal of the First Nations aboriginal group related the activities and agreements that they are pursuing for part ownership of a Mackenzie delta pipeline, as a stake hold for their future.

A wide ranging discussion of a two pipeline scenario ensued about which could go first, the potential of one stranding the other, market availability, et al. The discussion underlined that even if the decision is to send Alaskan gas down the highway route, there still was linkage to a Mackenzie gas line project.

Sen. Torgerson said some information and issues he would expect the international committee to address are:

1) Sharing Arctic gas for the benefit of Arctic communities.
2) Taxes: How to handle with different jurisdictions.
3) Net back to well head.
4) Local hire issues.
5) FERC and Canadian National Regulatory issues.
6) Producer requirements.

Minister Handley said he was appreciative of the frank discussions, would take the proposal under advisement and speak with the Premier Kakfwi.

5:00 p.m. Reception in the Great Hall of the Legislative Assembly with Ministers, Members of the Legislative Assembly and Yellowknife civic leaders.
Delegation's contribution of Alaska crab to the buffet table was well received.
Hon. Tony Whitford , Speaker of the House served as Master of Ceremonies.
Sen. Torgerson and Minister Handley spoke on the merits of the meeting.

YELLOWKNIFE, Wed., Aug 22

10:45 – Noon Tour the Legislative Assembly, hosted by Speaker Whitford.

1:00- 4:30 Private meetings.

Rep. Chenault, Rep. Joule as well as Brower, Mendenhall, and Laasch returned to Alaska.

EDMONTON, ALBERTA, Thur., Aug. 23

9:00 – 11:30 am Meeting with Alberta government officials.

Alberta Delegation:

Hon. Murray Smith, Minister of Energy
Hon. Pearl Calahasen, Minister of Aboriginal Affairs & Northern Development
Mr. Mel Knight, MLA
Mr. LeRoy Johnson, MLA
Mr. Luke Ouellette, MLA
Mr. Jamie Davis, Office of the Premier
Mr. Ricardo Shillingford, Ex. Assistant to Minister of Energy
Mr. Ken Smith, Deputy Minister, Energy
Mr. Stan Wenger, ADM, Electricity and Gas
Mr. Rory Campbell, ADM, Trade & Investment, Economic Development
Mr. Wayne Clifford, ADM, International & Intergovernmental Relations
Ms. Melanie McCallum, Director US/Latin America
Mr. Marvin Schneider, Director, Asia-Pacific

Minister Smith welcomed the delegation and said he was excited to be working with President Bush's energy plan. He said the politics of the gas pipeline could be complex but he was ready to help in any way. He acknowledged the presence of Minister Calahasen and the importance of aboriginal involvement in resource developments. He expects the next 10 years to be a very active and exciting time for the Northwest corner of the continent.

Senator Torgerson said that in the next 6 to 8 months decisions and relationships will be established that will substantially determine the manner and conditions by which Arctic gas will be brought market. This was his motivation for proposing an international committee of the participating Canadian governments and Alaska to exchange information and work on issues of mutual concern.

Sen. Torgerson and other members of the delegation went on to explain Alaska's 12 ½ percent ownership share of North Slope gas and the need for in-state use of some of these resources. This is why the state objects to any over-the-top route proposal. The tenor of the discussions with NWT officials was related and

questions that arose surrounding a two-pipeline strategy to bring Mackenzie delta gas to market.

A presentation of Alberta's gas field developments and related infrastructure was presented. Alberta supplies 25 percent of total US-Canadian gas production. Its pipeline network reaches the US Pacific Coast, Midwest, and Northeast markets. They project in increase in the North American demand for gas at 20 Bcf/c by year 2010. This would adequately accommodate 4 Bcf/d of Alaskan gas. In question and answer exchanges, it was observed that other natural gas resources in the far east and Mexico could be developed to supply California energy needs by companies that are also prominent in the North.

Minister Calahasen said the Alberta government is committed to respecting treaty obligations to First Nations aboriginal groups. It is the government's policy that the First Nations are involved to the maximum benefit possible in gas resource developments. This is usually accomplished through the encouragement of joint venture arrangements. They have on going consultation with the First Nations on the progress of pipeline plans.

Minister Smith said they were developing a proposal for Alberta to be a hub for the transportation of northern gas resources to North American markets. Stan Wenger outlined the concept which relies on the existence of an interconnected pipeline network with excess capacity and the ability to store large amounts of gas. The hub operates much like a bank. Once a supplier puts gas into the pipeline network, he may instantly deliver to any outlet although it is unlikely to be the supplier's actual gas product. Such an operation allows suppliers the maximum trading flexibility where they can quickly adjust to market changes and respond to new market opportunities for economic benefit. It also provides the least cost expandability.

Currently, there is 1.5 Bcf/d excess capacity in the Alberta network. Pipeline companies are studying the proper mix of increased capacity to their own systems (to West Coast, Midwest, and Northeast US markets) necessary to handle the 4 Bcf/d of Alaskan gas as well as Alberta gas production increases and other Canadian new production. There was some questioning of how tariffs, net back calculations, and resolving the value between a supplier's input and outtake gas would work. Since the meeting time was at an end Minister Smith said Stan would be available to the state at anytime for a further presentation and additional information. He observed that this was the first time that they had publicly presented this proposal and planned a broader discussion with interested parties in the near future.

Minister Smith thanked the delegation for its efforts to establish closer cooperation between the various governments on pipeline developments. He agreed that was a need for better exchange of information and would pursue the idea of establishing an inter-governmental committee.

11:30 am – 1:00 p.m. Working lunch with University of Alberta Chancellor John Ferguson and nine faculty members engaged in academic and research disciplines pertaining to industry relations, regulatory economics, petroleum engineering, international relations, circumpolar research and Native and anthropological studies.

Chancellor Ferguson welcomed the opportunity to have faculty members meet with the delegation and describe the university's involvement the development activities of the North. This occurred as individual discussions between members of the two groups. Sen. Torgerson thanked Chancellor Ferguson for the hospitality and hoped to encourage University of Alaska President Mark Hamilton to reciprocate at a future meeting.

1:30 pm – 3:00 pm. Meeting with Alberta gas supplier and producer associations sponsored by the Ministry of Economic Development.

Delegation:

Mr. Rick Sloan, Asst. Deputy Minister, Alberta Economic Development
Ms. Jan Reurink, Alberta Economic Development
Mr. Greg Stringham, Canadian Association of Petroleum Producers
Mr. Brad Lock, Canadian Gas Processors Association
Mr. Grant Monsour, Canadian Gas Processors Suppliers

Deputy Minister Sloan introduced the other participants and they presented a composite description of the growth and current status of Alberta's natural gas production, handling and transportation facilities, and value added processing. Greg Stringham said his association was neutral on which route should be chosen. Other aspects emphasized were the new technologies successfully developed for application in northern geologic and climactic conditions. Presenters also described the associations' training programs that supply the work force for Alberta's gas production and processing.

6:30 pm – 9:00 pm Informal barbecue hosted by Minister Smith with approximately 24 attendees invited from government and the private sector. Delegation members benefited from a variety of individual conversations with industry and government leaders. Minister Smith again thanked the delegation for initiating the discussions.

VANCOUVER, BRITISH COLUMBIA, Fri., Aug. 24

11:00 am – 2:00 pm Meeting in an airport conference room

Delegation:

Hon. Greg Halsey-Brandt, Minister of State for Intergovernmental Relations
Mr. Andrew Wilkinson, Deputy Minister, Intergovernmental Relations
Mr. Jack Ebbels, Deputy Minister of Energy and Mines
Mr. Keith Ogilvie, Senior Advisor, International Relations
Ms. Karen Koncohrada, Director, Minerals, Oil and Gas Branch

Sen. Torgerson presented the reasons Alaska was seeking face to face meetings with Canadian governments involved in a gas line project to Alaska's arctic coast. He also related some of the discussions with the other Canadian governments.

Minister Halsey-Brandt observed that the current British Columbia government is only 90 days old and is just getting established. Their present attitude is to support whatever the producers determine as the most feasible. Deputy Minister Ebbels stated the B.C. has gas production activities in its northern area. This is also an area that has pending Native land claims and the government is working with the different groups for settlements and participation in gas resource developments. He noted that there already was a gas line coming down from that area, through the province, and into the US Pacific Northwest. He suggested that this line could be linked with the Alaska gas line going to Alberta. There were wide ranging exchanges on different aspects of Alaskan and Canadian gas developments and transportation questions. The ministers agreed that there was merit in a closer cooperation with the other governments and would give Alaska's proposal serious consideration.

6:00 pm Alaska delegation departs for Alaska.

SCOMM

129:4

9/19

ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

Official Business

Senator John Torgerson, Chair
Senator Rick Halford
Senator Pete Kelly
Senator Johnny Ellis

Representative Joe Green, Vice-Chair
Representative Brian Porter
Representative Scott Ogan
Representative John Davies

AGENDA

Anchorage Legislative Information Office
Basement Conference Room

September 19, 2001
9:00 a.m. – 6:00 p.m.

Topic: Producer's Legislation

Wednesday, September 19

9:00 a.m. – 9:05 a.m. Call to Order and Introductions

9:05 a.m. – 11:00 noon Section by section overview/discussion of Producer's Legislation

Patrick Coughlin, Special Consultant to the Senate Resources Committee

Producer's Team

Foothills Pipe Lines, Ltd.

Anadarko/ Alberta Energy

Alaska Gasline Port Authority

Session: January – May
State Capitol, #427
Juneau, AK 99801
Phone: 907-465-2828
Fax: 907-465-4779

Interim: May – December
35477 Kenai Spur Hwy., Suite 101A
Soldotna, AK 99669
Phone: 907-260-3041
Fax: 907-260-3044

11:00 a.m. – 12:00 noon	Public Testimony (limit to three minutes unless previously arranged by chair)
12:00 p.m. – 1:30 p.m.	Lunch Break
1:30 p.m. – 1:45 p.m.	Nan Thompson, Chair of Regulatory Commission of Alaska
1:45 p.m. – 2:00 p.m.	John Katz, Director of State/Federal Relations and Special Counsel to the Governor
2:00 p.m. – 6:00 p.m.	Committee discussion on federal legislation

Alaska State Legislature

Senator John Torgerson, Chair
Phone (907) 260-3041
Fax (907) 260-3044

Representative Joe Green, Vice Chair
Phone: (907) 269-0123
Fax (907) 269-0124

Joint Committee on Natural Gas Pipelines

FOR IMMEDIATE RELEASE: Sept. 12, 2001
CONTACT: Sen. John Torgerson, (907) 260-3041; Rep. Joe Green, (907) 269-0123

Chairman Restates Pipeline Route Preference

Producer Threats Won't Sway Legislature From Southern Route

(ANCHORAGE) – Responding to published threats that natural gas producers would abandon their pipeline feasibility studies if government ruled any route off-limits, the chairman of the Joint Committee on Natural Gas Pipelines on Monday strongly restated the Legislature's opposition to an "over-the-top" route that would deny Alaska the greatest benefits of North Slope gas development.

"The 'over-the-top' line is just not going to happen," said Sen. John Torgerson (R-Kasilof), chairman of the joint pipeline committee. "The Legislature passed a law against it last session, Rep. Don Young inserted language in the energy bill the House passed opposing it, Sens. Ted Stevens and Frank Murkowski oppose it in the Senate, the North Slope Borough opposes it, the Eskimo whalers oppose it and folks all over Alaska oppose it. How much clearer do we have to be?"

"Bringing North Slope gas through a southern pipeline is our best chance to fuel Alaska's economy into the 21st century," said Rep. Joe Green, vice chairman of the joint pipeline committee. "It means more construction and operations jobs for Alaskans, a reliable source of power for countless Alaska communities, and a source of hydrocarbon feed stock that could nurture a home-grown petrochemical industry in the North."

Following full and frank discussions on the issue with Torgerson and Green, BP's Gas Business Unit Leader Ken Konrad said Monday that the consortium understands and respect the Legislature's responsibility to advocate for gas development that benefits all Alaskans. He said the group is continuing its studies, and would work with the Legislature to find mutually acceptable solutions to any challenges that arise.

"We are not going to do a project that Alaska doesn't want," Konrad said.

While producers claim an over-the-top route would be shorter and could cost less to build, Green said it carries significant negatives, including: the environmental hazards of building undersea pipeline in an Arctic marine zone with massive ice scouring; concerns for the bowhead whales that are the foundation of the Inupiat Eskimo culture and subsistence hunting; and the long delays, high costs and low probability of winning government permits to build along the coast.

(MORE)

In a related development, a gas industry trade paper on Monday quoted a consortium employee as saying that neither of the two routes under consideration is economically viable because "the state is unwilling to give us a tax structure for our modeling." Konrad said that statemen resulted from a miscommunication.

"We are working productively with the State to understand the many issues and options," Konrad said. "It's in the best interest of both the State and investors to have fair and certain rules around taxes before major commitments are made."

The joint pipeline committee will continue working energetically to address and resolve any issues that might impede progress on one of the most important economic issues before the state, Torgerson said. He noted that Committee members recently concluded an official protocol mission to solicit cooperation with Western Canadian governments on pipeline issues, and that the committee would continue its statewide meetings to take testimony from industry experts and the public with a meeting in Anchorage on Sept. 19.

"Following that meeting, I will be traveling to Washington, D.C. on behalf of all Alaskans, to make clear the state Legislature's opposition to the over-the-top route," Torgerson said.

"Alaska's natural gas is the energy of the future, and finding a way to get this gas to market is one of the most important development prospects on Alaska's economic horizon," Green said. "The people want it, the Legislature wants it and the industry wants it. I have every confidence that we can all work together for a gasline project that will benefit everyone."

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ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

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Representative Brian Porter
Representative Scott Ogan
Representative John Davies

SEP 14 2001

MEMORANDUM

To: Members of the Joint Committee on Natural Gas Pipelines

From: Senator John Torgerson, Chair

Re: Backup Material for September 19 meeting of the Joint Committee on Natural Gas Pipelines regarding Producer's legislation.

Date: September 11, 2001

TABLE OF CONTENTS

1) Alaska Gas Pipeline Status Report
2) Producer's Legislation
3) Sectional Analyses of the Producer's Legislation
   a) Producers
   b) Senate Resources Committee, prepared by Patrick Coughlin
   c) Foothills Pipe Lines, Ltd.
   d) Anadarko
   e) Mike Macy
4) Foothills Pipe Lines, Ltd. letter dated September 11, 2001 regarding possible alternative federal legislation.
5) Van Ness Feldman, Attorneys for Foothills, letter to Senator Murkowski
6) Foothills Pipe Lines, Ltd. withdrawn partner list
7) Floor remarks by Senator Bingaman, Chair of the U.S. Senate Energy and Natural Resources Committee.

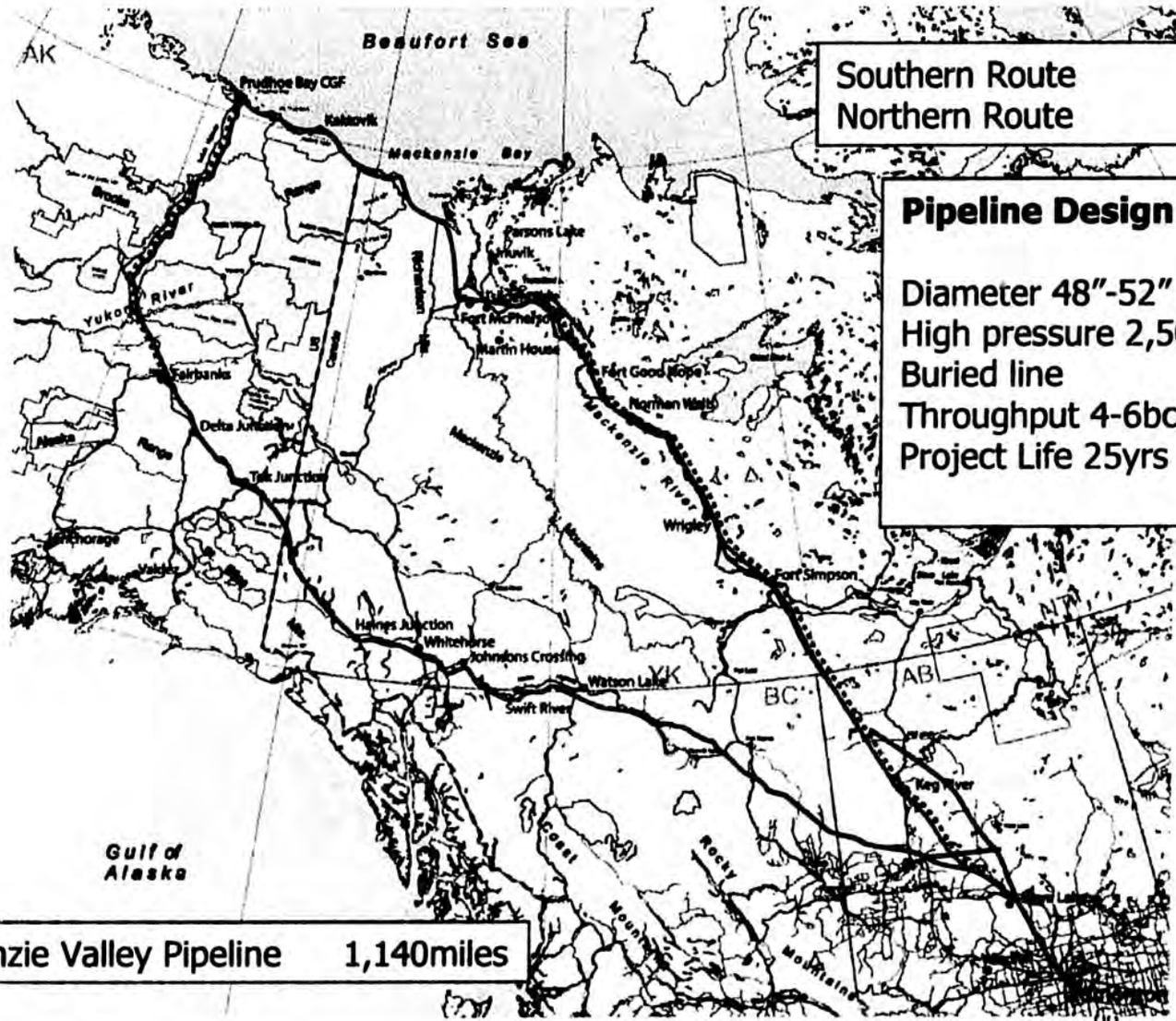
Session: January – May
State Capitol, #427
Juneau, AK 99801
Phone: 907-465-2828
Fax: 907-465-4779

Interim: May – December
35477 Kenai Spur Hwy., Suite 101A
Soldotna, AK 99669
Phone: 907-260-3041
Fax: 907-260-3044

Alaska Gas Pipeline Status Report

- Feasibility study underway – expect engineering to be completed by year-end.
- Sharing interim/preliminary data.
  - Comparison of route attribute elements
- Many issues are being evaluated, including:
  - Technology and constructability (costs)
  - Beaufort Sea construction
  - Expandability
- Current analysis indicates project is not presently economic.
  - Cost uncertainty
  - Market volatility
  - Regulatory/political risks
  - Fiscal risks

Preliminary Comparison of Two Pipeline Routes



Southern Route	2,139miles
Northern Route	1,803miles

Pipeline Design Basis

Diameter 48"-52"
High pressure 2,500-3,000psi
Buried line
Throughput 4-6bcf/d
Project Life 25yrs

Note: Mackenzie Valley Pipeline 1,140miles

ExxonMobil

Outline of Information

- Comparison of route attribute elements.
  - Economics
  - Government Revenues
  - Alaska Gas Access
  - Jobs
  - Environment
  - Safety
  - Timing
- Continued joint producer study only justified if:
  - Federal enabling legislation (regulatory efficiency) enacted.
  - State of Alaska fiscal certainty progressed.
  - Route not mandated.
- Summary of Current Status
  - Recap and conclusions.

Element 1: Economics

Neither Route Is Economic

Total Project Cost ($bn)
(4.0bcf/d from Alaska, 0.8bcf/d from MD)

	South	North
Gas Treatment Plant	2.6	2.7
Alaska to Alberta	9.0	6.8
Alberta to Market	5.3	5.3
NGL Extraction Facilities	0.3	0.3
Alaska Project Total	**17.2**	**15.1**
Mackenzie Delta Line	2.3	0.9
Pt.Thomson Development	1.3	1.3

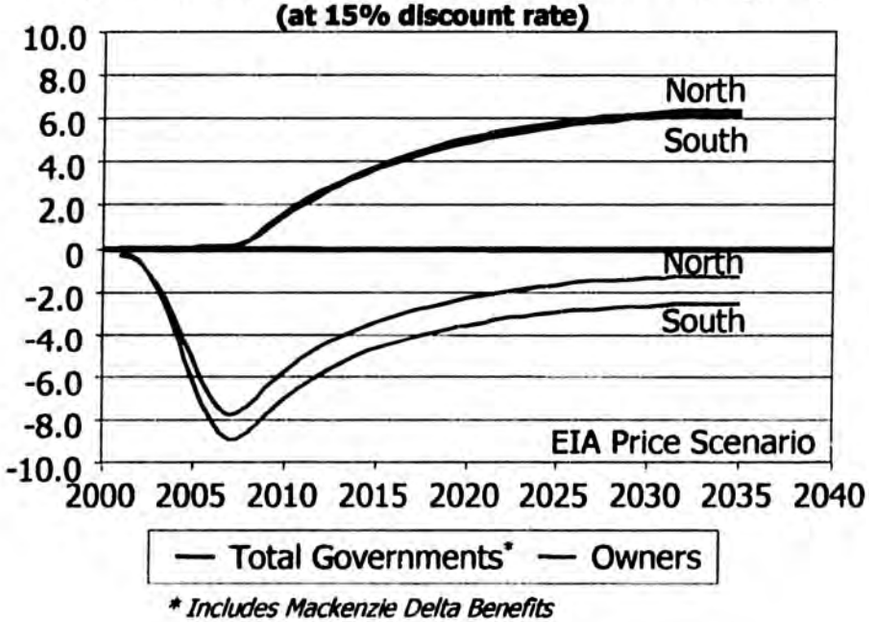
Notional Toll ($/mcf)
(Alaska North Slope to US L-48 Market)

	South	North
Gas Treatment Plant	0.30	0.32
Alaska to Alberta	1.31	0.97
Alberta to Market	0.78	0.78
Total	**2.39**	**2.07**

Price Assumptions

- Based after EIA, ~$3.00/mmbtu, escalating with inflation.
- View 2000 price spike as an anomaly.

Project Discounted Cumulative Cash Flows ($bn)
(at 15% discount rate)



** Includes Mackenzie Delta Benefits*

- Owner's investment not repaid.
- Additional risk from price and cost uncertainty.
- Team is still working to improve economics by lowering costs.

bp ExxonMobil Phillips 66

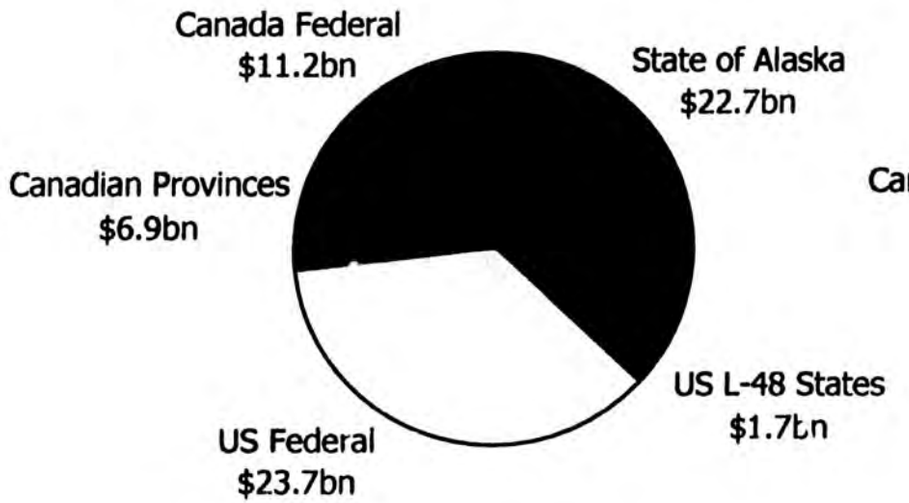
ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2948 SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPLINE, 2001-02

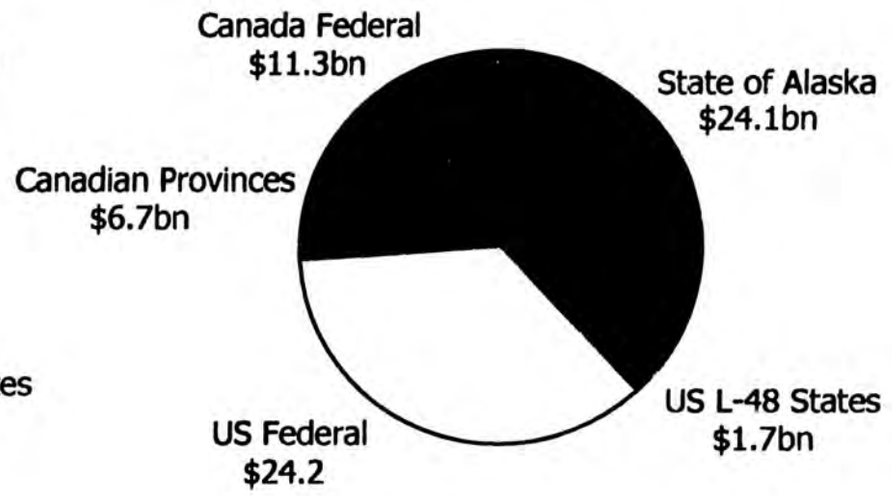
Element 2: Revenues

Substantial Government Revenues Regardless of Route

Total Undiscounted Revenue
South
$66.2bn, MoD



Total Undiscounted Revenue
North
$68.0bn, MoD



Assumptions:

- Both routes include MD upstream and midstream revenues.

Element 3: Gas Access

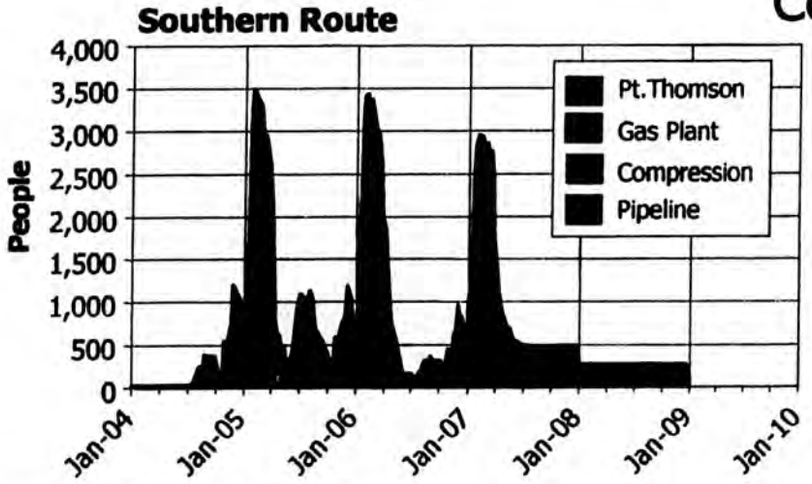
Gas to Alaska Is Important to State

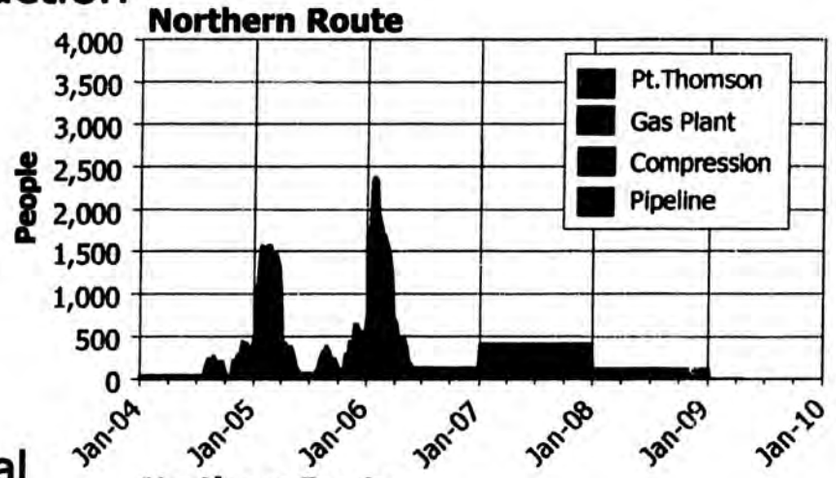
- We understand this issue is a priority for the State.
  - Looking for positive solution regardless of route.
- Alaska gas demand is small relative to overall project throughput.
  - Mid-term South Central demand could be met through Cook Inlet.
  - Fairbanks energy demand would require significant investment to convert to gas; initial volumes 10-20mmscf/d.
  - Desire to meet potential future gas demand is understood.
- Alaska demand can be met with either route.
  - Southern route will run through Alaska.
  - A third-party or government funded trunk line to Fairbanks for Northern route could provide similar access to gas in Alaska as a Southern route.
- A lower-cost Northern Route generates sufficient incremental revenue for participating governments to fund building of a trunk line from Pump Station 4 to Fairbanks.

Element 4: Jobs

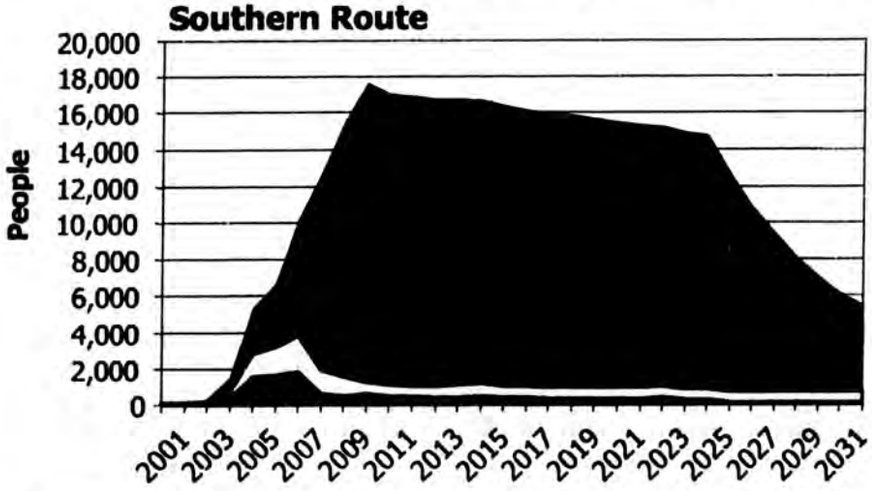
Massive Number of Alaska Jobs for Either Route

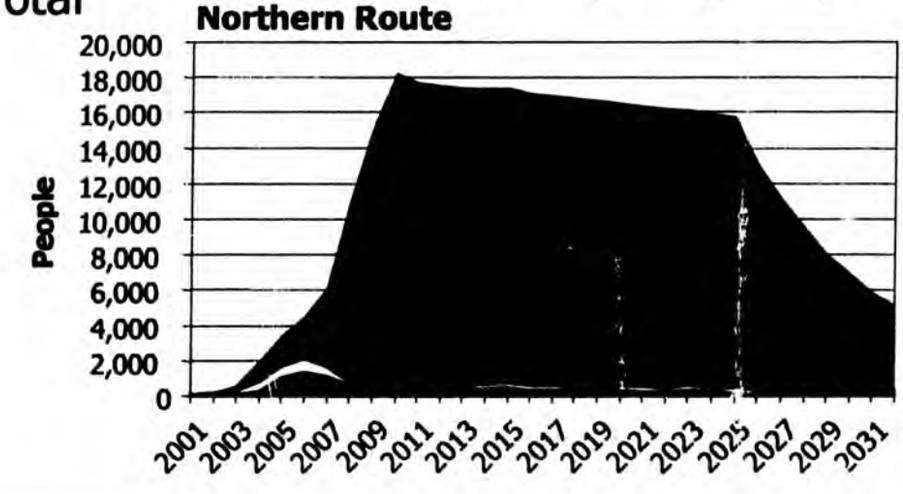
Construction





Total





Direct Jobs	- Jobs directly associated with construction, installation, and operation.
Indirect Jobs*	- Support industry jobs including activities such as hauling, catering, etc.
Induced Jobs*	- Jobs created by increased government and household spend.

Pt.Thomson | Project Direct | Project Indirect | Project Induced

** Per Northern Economics, 2001.*

bp ExxonMobil Phillips 66

Element 5: Environment

Footprint and Beaufort Sea Considerations

	South	North
New Infrastructure (acres)	19,800	17,200
Threatened or Endangered Species Along Route (#)	4	5
Important Wildlife Habitat (miles)	340	440
Environmentally Managed Areas (miles)	300	0
Previously undisturbed corridor (miles)	200	450 Land, 240 Sub-sea
Total CO_2 Emissions (million tons/year)	2.5	2.0
Compressor Stations (#), horsepower (thousands)	11/512	12/532
Overall Length (miles)	2,139	1,803

- If they occur, gas "spills" vaporize and have significantly less of an environmental challenge than oil spills
- Operation of Beaufort Sea pipeline does not present a known impact to Bowhead whales
  - Possible impact of noise not yet studied
  - Whale migration could be impacted if maintenance or repairs required
- Construction of Beaufort Sea pipeline presents point-source turbidity and noise issues for whale migration
  - May be mitigated by 80-day annual construction window
  - Construction spreads planned to minimize potential interaction with whales (managed same as historic seismic survey activity).
- Northern Route follows same ROW as proposed Mackenzie Delta pipeline.
  - North impacts less than shown if assume MD pipeline built.

Element 6: Safety

Both Routes Are Safe

	South	North
Potential Ice Scour	0 miles	240 miles
Steep Slopes	300 miles	-
Seismic Zones	780 miles	-
Water Crossings (#)	950	650
Continuous Permafrost	250 miles	260 miles
Discontinuous Permafrost	1,470 miles	1,140 miles

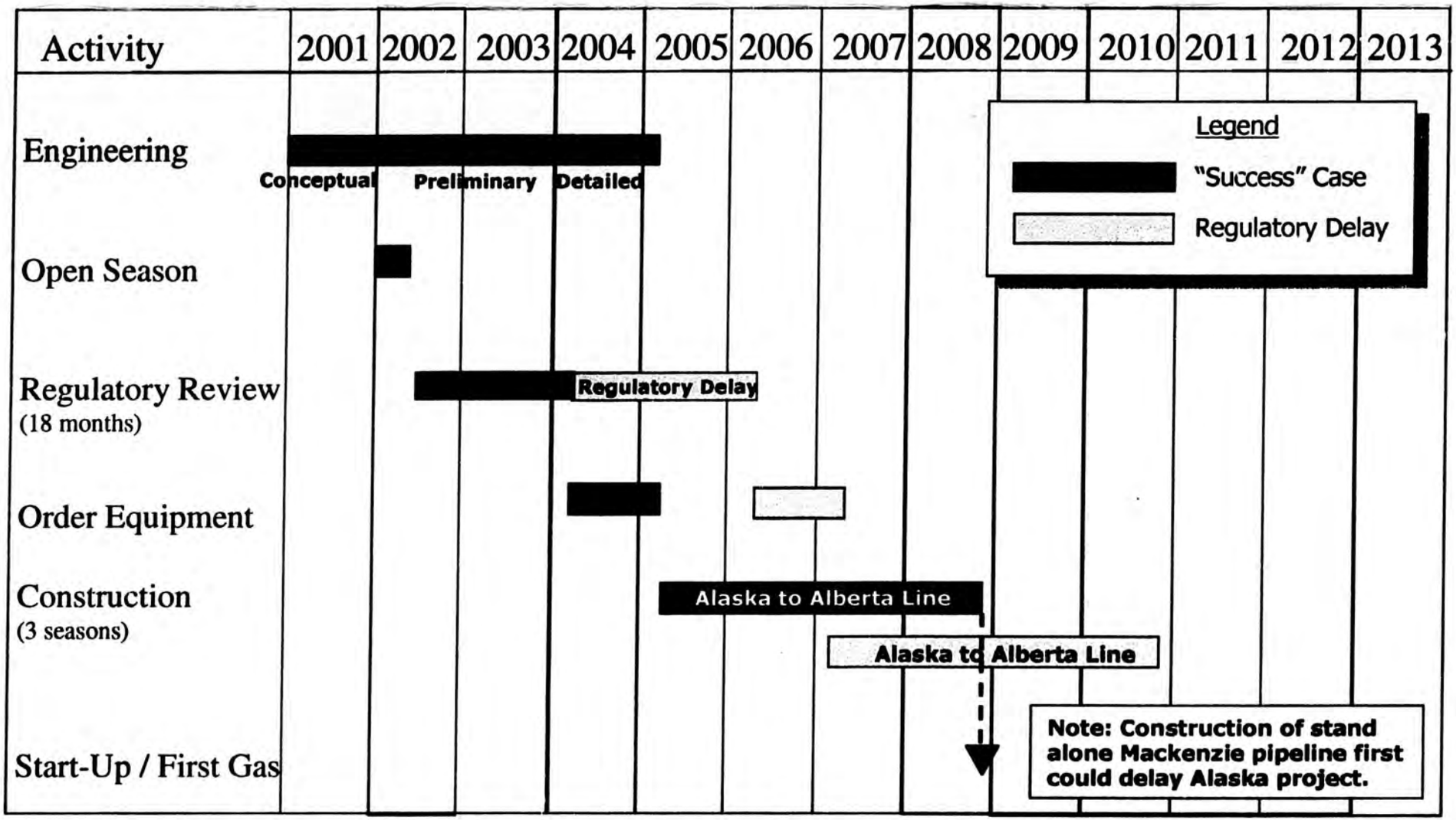
- No show stoppers at present
  - State-of-the-art technology and design, inherently safe and reliable
  - Extensive pre-installment testing
  - Design for permafrost and discontinuous permafrost
  - Aggressive monitoring (smart pigs, etc)

- Seismic activity
  - Design pipeline to tolerate movement in 3 dimensions (ductile design, expansion joints, etc)
  - Bury in soft "bedding"

- Ice gouging and strudel scour
  - Survey to identify depth of historical scours and subsea geotechnical environment
  - Identify where scour is minimized as much as possible and subsea is suitable for trenching; bury below scour depth

Element 7: Timing

Challenges for Both Routes, Regulatory Efficiency Key to Success



U.S. Regulatory Enabling Legislation

- New legislation does not alter ANGTA; ANGTA remains in place
  - Does not preclude Foothills project proceeding under ANGTA
- Creates market-driven, expedited regulatory process for <u>any</u> viable project(s)
  - Subject to FERC regulation; fair and reasonable terms and conditions; open access
  - Subject to all environmental laws and regulations; 18 month EIS completion
- Creates Office of Federal Pipeline Director in executive branch to coordinate all related government activity
- Provides timely judicial review
- Mitigates regulatory uncertainty/risk
- Essential for continued joint producer study

Alaska State Fiscal Certainty

- Predictability / certainty are vital. Not possible to commit to project if State can later revise project economics
  - Simplification of Royalty / Severance tax valuation
  - Ad valorem tax
  - Royalty-in-value vs Royalty-in-kind – long term commitment - every 6 months commitment
- Potential vehicle:
  - Fiscal contract endorsed by legislature
  - 3rd Party dispute resolution.

Closing / Re-cap

- Current analysis indicates project is not presently economic
- Work continues on engineering & design, field work. $50 million spent to date. Year end target.
- No route decisions have been made; options must not be mandated.
- Governments can help:
  - Enact regulatory enabling legislation – 1st Priority
  - Accelerated depreciation (US and Canada)
  - State of Alaska fiscal certainty
  - Do not foreclose options
  - Work cooperatively (US, Alaska, Canada, First Nations) and be supportive
- Continued joint producer study only justified if:
  - Federal enabling legislation (regulatory efficiency) enacted.
  - State of Alaska fiscal certainty progressed.
  - Route not mandated.
- Successful project = Large benefit for consumers and governments.

S._____

IN THE SENATE OF THE UNITED STATES

A BILL

To Expedite the Approval, Construction, and Initial Operation of One or More Economically Viable and Environmentally Sound Transportation Systems for the Delivery of Alaska Natural Gas to the Lower 48 States.

Be it enacted by the Senate and the House of Representatives of the United States of America in Congress assembled,

SEC. 1. SHORT TITLE.

This Act may be cited as the "Alaska Natural Gas Pipeline Act of 2001."

SEC. 2. CONGRESSIONAL FINDINGS.

(a) The Congress finds and declares that —

(1) Over the next 20 years, the demand for natural gas in the United States is expected to increase by more than 50 percent, and the nation's anticipated production, at current growth rates, will fall far short of that level of demand.

(2) One of the largest known reserves of natural gas in the United States, estimated at over 35 trillion cubic feet, is located in Alaska, in the vicinity of Prudhoe Bay. In addition, it is estimated that there may be up to 100 trillion cubic feet of natural gas on the North Slope of Alaska.

(3) If delivered to the Lower 48 States, the known and expected natural gas resources on the North Slope of Alaska would make an important long-term contribution to the nation's energy supplies. At present, however, there is no natural gas pipeline system connecting the North Slope of Alaska to the Lower 48 States.

(4) In 1976, Congress enacted the Alaska Natural Gas Transportation Act (ANGTA), 15 U.S.C. § 719, to expedite completion of a pipeline system connecting the North Slope of Alaska to the Lower 48 States. ANGTA authorized the President and Congress to designate a single project as the Alaska Natural Gas Transportation System (ANGTS), which would be entitled to the benefit of a streamlined regulatory approval process and limited judicial review.

(5) In 1977, the President and the Congress designated an ANGTS project, and the southern portion of that project (known as the "pre-build") was completed between Alberta and the Lower 48 States in the 1980s and early 1990s.

(6) Despite the passage of more than 20 years, parties seeking to develop the Alaska-to-Alberta section of the ANGTS project have been unable to

obtain the regulatory approvals or attract the financing necessary to permit construction of the project to begin.

(7) As a result of the passage of time, some design features mandated for the Alaska-to-Alberta section of the ANGTS project would have to be modified to take full advantage of current technological capabilities, and other changes also may be needed to ensure an economically, environmentally, and technically sound approach.

(8) The nation's energy supply situation has changed in recent times, thereby triggering renewed interest in a variety of proposals to construct transportation facilities to move Alaska Natural Gas to markets in the Lower 48 States.

(9) In concert with this renewed interest in understanding technical requirements and determining if an economically viable transportation system can be developed, an important first step in assessing economic viability is to know whether regulatory approvals can be obtained and environmental impacts assessed in a timely fashion.

(10) Therefore, it is in the national interest to:

(i) encourage the renewed interest in proposals to bring about the transportation of Alaska Natural Gas tc the Lower 48 States;

(ii) provide as much regulatory certainty and expedition as practicable for approval and implementation of any such environmentally sound proposals to enhance their prospects of economic viability

and development and thereby to provide the nation with the benefit of one or more cost-effective transportation systems;

(iii) allow for the possibility that the market may support now or in the future the construction of more than one transportation system to move Alaska Natural Gas efficiently to the Lower 48 States;

(iv) rely on competitive market forces, to the maximum extent possible, in determining the future development of Alaska Natural Gas supplies;

(v) encourage the development of one or more pipeline systems for transporting Alaska gas to the Lower 48 States in a manner consistent with

(a) maximizing the delivery of a long-term, reliable supply of natural gas to the Lower 48 States, as soon as possible; and

(b) complying with all applicable environmental laws

SEC. 3. CONGRESSIONAL STATEMENT OF PURPOSE

The purpose of this Act is to expedite the approval, construction, and initial operation of one or more transportation systems for the delivery of Alaska Natural Gas to the Lower 48 States by:

(a) relying on competitive market forces to determine which such system or systems can be built and operated in an economically viable manner;

(b) providing for the expedited review and approval of applications for a certificate of public convenience and necessity and related federal approvals for one or more pipelines transporting Alaska gas to the Lower 48 States;

(c) ensuring the full consideration of environmental impacts and related concerns during the review of any proposed Alaska Gas Projects, consistent with the need to expedite such reviews;

(d) creating an Office of Federal Pipeline Director to direct the efficient and coordinated participation of, and decision-making by, the various federal agencies and other governmental interests involved in the review and approval of one or more Alaska Gas Projects; and

(e) expediting the resolution of, and limiting the jurisdiction of the courts to review, disputes concerning any aspect of this legislation or the approval process for any Alaska Gas Project.

To accomplish this purpose, Congress intends to exercise its constitutional powers to the fullest extent in the authorizations and directions contained herein.

SEC. 4. DEFINITIONS.

As used in this Act:

(1) the term "Alaska Gas Project" means any Alaska Facilities Gas Project or Lower 48 Facilities Gas Project;

(2) the term "Alaska Natural Gas" means natural gas derived from the area of the State of Alaska generally known as the North Slope of Alaska, including the Continental Shelf thereof;

(3) the term "Commission" means the Federal Energy Regulatory Commission;

(4) the term "Lower 48 States" means the contiguous States of the United States of America;

(5) the term "Lower 48 Markets" means any market for the consumption of natural gas that is located within the Lower 48 States;

(6) the term "Alaska Facilities Gas Project" means any natural gas pipeline system that carries Alaska Natural Gas from the area generally known as the North Slope of Alaska to the border between Alaska and Canada, including any related facilities that fall within the jurisdiction of the Commission; and

(7) the term "Lower 48 Facilities Gas Project" means any natural gas pipeline system that carries Alaska Natural Gas from the border between Canada and the Lower 48 States to any Lower 48 Markets, including any related facilities that fall within the jurisdiction of the Commission.

SEC. 5. EXPEDITED APPROVAL PROCESS.

(a) Section 2 of the Natural Gas Act is amended to include the following additional definitions:

(11) "Alaska Natural Gas" means natural gas derived from the area of the State of Alaska generally known as the North Slope of Alaska, including the Continental Shelf thereof.

(12) "Lower 48 States" means the contiguous States of the United States of America.

(13) "Lower 48 Markets" means any market for the consumption of natural gas that is located within the Lower 48 States.

(14) "Shipper" means, for purposes of section 7(c)(3) and (4) of this Act, any person that has entered into an agreement with a person that is or will

upon its issuance become the holder of a certificate of public convenience and necessity authorizing an Alaska Facilities Gas Project or a Lower 48 Facilities Gas Project for the purpose of transporting Alaska Natural Gas.

(15) "Alaska Facilities Gas Project" means any natural gas pipeline system that carries Alaska Natural Gas from the area generally known as the North Slope of Alaska to the border between Alaska and Canada, including any related facilities that fall within the jurisdiction of the Commission.

(16) "Lower 48 Facilities Gas Project" means any natural gas pipeline system that carries Alaska Natural Gas from the border between Canada and the Lower 48 States to any Lower 48 Markets, including any related facilities that fall within the jurisdiction of the Commission.

(b) Section 7(c) of the Natural Gas Act is amended to include the following additional paragraphs:

"(3) Notwithstanding any other provision of law, the Commission shall issue a certificate of public convenience and necessity to any person for the construction and operation of an Alaska Facilities Gas Project where:

(A) such person has reached agreement with a Shipper of Alaska Natural Gas for the transportation of natural gas through an Alaska Facilities Gas Project on behalf of such Shipper with the intent that all or a portion of such Alaska Natural Gas, along with any other natural gas, will ultimately be delivered to Lower 48 Markets for consumption; provided, however, that the Commission shall not consider the present extent of

transportation capacity downstream of the proposed Alaska Facilities Gas Project;

(B) rates and charges for, and terms and conditions of, such transportation services can be established in accordance with the procedure provided in subsection (e) of this section; and

(C) terms and conditions for compliance with all environmental laws applicable to the proposed Alaska Facilities Gas Project can be established in accordance with the procedure provided in subsection (e) of this section.

Upon the filing of any such application, the Commission shall determine within 18 months whether the agreement between the Shipper and such person meets the requirements of (A) and whether the matters identified in (B) and (C) can be established in accordance with subsection (e) of this section, and, if so, the Commission shall within such period make the findings, attach such reasonable terms and conditions as the public convenience and necessity may require, and issue a certificate, all in accordance with the procedure provided in subsection (e) of this section.

(4) Notwithstanding any other provision of law, the Commission may issue a certificate of public convenience and necessity authorizing the construction and operation of a Lower 48 Facilities Gas Project to any person that has reached agreement with a Shipper of Alaska Natural Gas that will have been first transported through an Alaska Facilities Gas Project for any continued transportation of such gas from the U.S. border with Canada to any destination

within the Lower 48 Markets, provided that the Commission makes the findings and attaches such reasonable terms and conditions therefor in accordance with the procedure provided in subsection (e) of this section."

SEC. 6. ENVIRONMENTAL REVIEWS.

(a) Separate EISs for Alaska Facilities and Lower 48 Facilities Gas Projects.

(1) Before a certificate of public convenience and necessity is issued for any Alaska Facilities Gas Project under Section 7(c)(3) of the Natural Gas Act, a single environmental impact statement shall be prepared for that project and for any gas conditioning plant developed in conjunction with such project in accordance with the National Environmental Policy Act, 42 U.S.C. § 4332(2)(C), and this Act. The preparation of an EIS for a project pursuant to this paragraph shall satisfy the NEPA obligations of each federal agency whose approval is required for that project.

(2) Before a certificate of public convenience and necessity is issued for any Lower 48 Facilities Gas Project under Section 7(c)(4) of the Natural Gas Act, a single environmental impact statement for that project shall be prepared in accordance with the National Environmental Policy Act, 42 U.S.C. § 4332(2)(C), and this Act. The preparation of an EIS for a project pursuant to this paragraph shall satisfy the NEPA obligations of each federal agency whose approval is required for that project.

(b) Any environmental impact statement prepared pursuant to subsection (a) of this section shall be prepared in accordance with the regulations and procedures of the lead agency designated for that statement in subsection (c) of this section.

(c) Lead agency for preparation of environmental impact statements.

(1) The lead agency for any environmental impact statement prepared pursuant to subsection (a)(1) of this section shall be the Commission.

(2) The lead agency for any environmental impact statement prepared pursuant to subsection (a)(2) of this section shall be the Commission.

(d) The preparation of any environmental impact statement prepared under subsection (a) of this section shall be expedited. The draft environmental impact statement shall be issued within 12 months after the certificate application is accepted for filing, and the final environmental impact statement shall be issued within 6 months thereafter, unless the Commission determines for good cause that additional time is needed to comply with environmental or other laws.

(e) The scope of any environmental impact statement prepared under subsection (a) of this section shall correspond to the scope of the certificate application for which such environmental impact statement is being prepared.

SEC. 7. FEDERAL PIPELINE DIRECTOR.

(a) The Office of the Federal Pipeline Director shall be established within the Executive Office of the President. The functions of the Office shall be directed by the Federal Pipeline Director, who shall be appointed by the President, by and with the advice and consent of the Senate.

(b) The Federal Pipeline Director shall be responsible for coordinating the expeditious discharge of all activities by federal agencies with respect to any Alaska Gas Project, from the pre-application consultation stage through the completion of project construction and initial operation. The Director also shall be responsible for coordinating the compliance by all federal agencies with the provisions of this Act with respect to such projects. Such coordination shall include requiring submission of scheduling plans for permits, certificates, grants, or other necessary authorizations. Such coordination may include serving as a "one window point" for filing and issuance of all necessary permits, certificates, grants, or other authorizations, and, consistent with law, federal government requests for data or information related to any application for a permit, certificate, grant, or other authorization. Upon the written agreement of the Director and the head of any federal agency, the agency may delegate to the Director any statutory function vested in such agency related to the functions of the Director, including permitting functions.

(c) The Federal Pipeline Director shall be responsible for coordinating the expeditious completion of all environmental and other studies and reviews of any kind that are required or conducted for any Alaska Gas Project. Such coordination shall include requiring the submission of detailed scheduling plans for completing such studies and reviews within the time periods allowed under this Act and also shall include requiring the submission of periodic reports

on agencies' compliance with such plans. Such coordination also may include serving as the "primary point of contact" for the federal government with any and all participants in such studies and reviews, including

(i) Federal agencies and officials, including those involved in the preparation of an environmental impact statement;

(ii) State, local, and tribal governments and non-governmental stakeholders; and

(iii) Canadian agencies responsible for decisions relating to the transportation of Alaska Natural Gas to the Lower 48 States.

(d) The Federal Pipeline Director shall semi-annually submit a detailed report to Congress on the status of all pending applications for Alaska Gas Projects.

(e) There is hereby authorized to be appropriated, beginning in fiscal year 2002 and each fiscal year thereafter, such sums as may be necessary to carry out the functions of the Office of the Federal Pipeline Director appointed by the President under section 7(a) of this title.

SEC. 8. AGENCY REVIEWS AND DECISIONS.

(a) All actions taken by any federal officer or agency with respect to an Alaska Gas Project shall be expedited, in a manner consistent with completion of the necessary reviews and approvals by the deadlines set forth in this Act.

(b) Federal agencies involved in the review or approval of an Alaska Gas Project shall cooperate and coordinate with one another, under the direction of the Federal Pipeline Director, to expedite the decision-making process and to minimize duplication of effort. Such cooperation and coordination efforts shall include, as appropriate, the following:

(i) memoranda of understanding with applicants or prospective applicants;

(ii) inter-agency memoranda of understanding;

(iii) inter-agency coordination procedures;

(iv) inter-agency coordination meetings;

(v) joint pre-filing or post-filing consultation meetings with project applicants;

(vi) joint public meetings; and

(vii) joint reports, studies, and other documents, including but not limited to the joint environmental impact statement required to be prepared for each Alaska Gas Project under section 6(a) of this title.

(c) Any certificate, right-of-way, permit, lease, or other authorization issued or granted for an Alaska Gas Project shall include the terms and conditions required by law, and may include terms and conditions permitted by law, except that with respect to terms and conditions permitted but not required, the federal officer or agency, notwithstanding any other provision of law, shall have no authority to include terms and conditions that the Federal Pipeline Director determines would prevent or impair in any significant respect the expeditious construction and initial operation of an economically viable and environmentally sound system for transporting Alaska Natural Gas to the Lower 48.

(d) Any federal officer or agency, with respect to any certificate, permit, right-of-way, lease, or other authorization issued or granted by such officer or agency for an Alaska Gas Project, may, to the extent permitted under laws administered by such officer or agency, add to, amend, or abrogate any term or condition included in such certificate, permit, right-of-way, lease, or other authorization except that with respect to any such action that is permitted but not required by law, such federal officer or agency, notwithstanding any such other provision of law, shall have no authority to take such action if the Federal Pipeline Director determines that it

would prevent or impair in any significant respect the expeditious construction and initial operation of an economically viable and environmentally sound system for transporting Alaska Natural Gas to the Lower 48.

SEC. 9. JUDICIAL REVIEW.

(a) Exclusiveness of Remedy. Notwithstanding any other provision of law, the actions of federal officers or agencies taken with respect to any Alaska Gas Project shall not be subject to judicial review except as provided in this section.

(b) Limitations on the Filing of Claims.

(i) Claims alleging the invalidity of this Act may be brought not later than the 60th day following its date of enactment.

(ii) Claims alleging that any action taken by a federal officer or agency in connection with as Alaska Gas Project will deny rights under the Constitution of the United States, or that any such action is in excess of statutory jurisdiction, authority, or limitations, or short of statutory right, may be brought may be brought not later than the 60th day following the date of such action, except that if a party shows that he did not know of the action complained of, and a reasonable person acting in the circumstances would not have known, he may bring a claim alleging the invalidity of such action not later than the 60th day following the date of his acquiring actual or constructive knowledge of such action.

(c) Exclusive Jurisdiction of Special Court. A claim under subsection (b) of this section shall be barred unless a complaint is filed prior to the expiration of the time limit specified in that subsection in the United States Court of Appeals for the District of Columbia

Circuit acting as a Special Court. Such court shall have exclusive jurisdiction to determine such proceeding, and no other court of the United States, or any state, territory, or possession of the United States, or of the District of Columbia, shall have jurisdiction of any such claim in any proceeding instituted prior to or on or after the date of enactment of this Act.

(d) Expedited Procedures. With respect to any claim under subsection (b) of this section, the United States Court of Appeals for the District of Columbia Circuit shall set the matter for expedited consideration, taking into account the national interest as defined in section 2 of this Act.

SECTION 10. SEPARABILITY.

If any provision of this Act, or application thereof, is held invalid, the remainder of this Act shall not be affected thereby.

ANGTA Comparison

- New Legislation does not alter ANGTA; ANGTA remains in place
  - Does not preclude project proceeding under ANGTA
- ANGTA
  - Historic attributes contrast today's environment
    - Deregulation of gas business
    - Not market driven
    - Major technology changes
    - Modern environmental standards are higher
  - Modern day project cannot support additional liabilities
  - Not route neutral

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Enabling Legislation - Outline

- Section 1 Short Title
- Section 2 Congressional Findings
- Section 3 Statement of Purpose
- Section 4 Definitions
- Section 5 Expedited Approval Process
- Section 6 Environmental Reviews
- Section 7 Federal Pipeline Director
- Section 8 Agency Reviews and Decisions
- Section 9 Judicial Review
- Section 10 Separability

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Section 5 – Expedited Approval Process

- FERC required to certificate Alaska to Alberta project if 3 criteria are satisfied:
  - Project backed by a shipping commitment
  - FERC is satisfied as to "rates" and "terms and conditions" (access)
  - FERC is satisfied as to compliance with applicable environmental laws
- FERC directed to act within 18 months
- FERC may certificate Alberta to Lower-48 market project following normal FERC Sec. 7 procedures

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Section 6 – Environmental Reviews

- Requires separate EISs for Alaska to Alberta and Alberta to Lower-48 markets
- Designates FERC as lead agency for both segments
- Sets EIS deadlines
  - Draft EIS, 12 months
  - Final EIS, 18 months
- Requires consistency between EIS scope and certification scope

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Section 7 – Federal Pipeline Director

- Establishes Office of Federal Pipeline Director
- Responsibility to coordinate the expeditious discharge of federal agencies' activities
- Authorizes funding and regular congressional reporting

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Section 8 – Agency Reviews and Decisions

- Directs federal agencies to expedite handling of project actions
- Requires federal agency coordination and cooperation via MOU's
- Prevents agencies from including discretionary terms if such terms would prevent or impair expeditious completion of the project

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Section 9 – Judicial Review

- Limits timing of challenges to 60 days
- Establishes jurisdiction to the DC Circuit Court of Appeals, and directs expedited consideration
- Judicial review is limited to claims of constitutionality or statutory authority

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Wrap Up

- In summary the enabling legislation does the following
  - Provides expedited review and approval of applications
  - Authorizes the appointment of a federal director
  - Expedites dispute resolution
  - Focuses on the North Slope to Alberta segment
  - Specifies FERC as lead agency for EISs
- The proposed legislation is an essential step to the market-based effort to bring Alaska gas to consumers in a manner consistent with today's environmental standards.

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Section Analysis
Proposed Alaska Natural Gas Pipeline Act of 2001 (Proposed Act)
Dated July 19, 2001

Prepared by Patrick Coughlin
Special Consultant to the Senate Resources Committee

I. Overview

In July of 2001, the Alaska Gas Producers Pipeline Team, composed BP, Phillips Petroleum, and Exxon, circulated to various state and federal government officials their Proposed Act. Its stated purpose "is to expedite the approval, construction, and initial operation of ... transportation systems for the delivery of Alaska Natural Gas to the Lower 48 States." The Proposed Act purports to advance this purpose by:

1. "relying on competitive market forces to determine" which transportation system can be built and operated in an economically manner; and
2. providing for various measures designed to expedite the review and approval of an application for such a transportation system, including the creation of the office of the Federal Pipeline Director to coordinate government efforts and limiting judicial review.

The stated purpose is curiously close to the stated purpose of the Alaska Natural Gas Transportation Act of 1976 (ANGTA).

> "The purpose of this chapter is to provide the means for making a sound decision as to the selection of a transportation system for delivery of Alaska natural gas to the [Lower 48] States ... and ... to expedite its construction and initial operation by (1) limiting the jurisdiction of the courts to review the actions of Federal officers or agencies taken pursuant to the direction and authority of this chapter, and (2) permitting the limitation of administrative procedures and effecting the limitation of judicial procedures related to such actions."

Both Acts contain similar provision relating to the creating a new Federal official to direct the agencies permitting efforts, expediting the permit approval process, limiting agency discretion, and limiting judicial review.

Under the ANGTA, an operator, Foothills Pipeline, and a route, the Alcan route, has been selected, through a lengthy process, which included a treaty with Canada, a Presidential finding and decision, and approval by Congress. Although not explicitly repealing the ANGTA, the Proposed Act would begin anew the selection process of both an operator and a route. The Producers claim that the ANGTA has been a "failure" and that the competitive market should be allowed to select a system/route rather than government.

Foothills, on the other hand, is wary about the assertion that a new federal law is necessary. Foothills believes that an Alcan route can be built quickly and efficiently

under the ANGTA without any statutory changes. Foothills is concerned about statements that a new law is "necessary" because it is possible that a new law will not pass. If that becomes the case, then the viability of the ANGTA has been called into question.

The Proposed Act would allow an "Over the Top" route. It would call into question the constitutionality of SB 164 that banned the Over the Top route as violating the federal Commerce Clause.

Moreover, the Proposed Act would allow the Producers themselves to be the only owners of the transportation system. Initially, under the ANGTA, the Producers were not allowed to have any ownership interest because of antitrust concerns. Later, the ANGTA was modified to allow the Producers to have some ownership interest. Both Foothills and other commentators have criticized the Proposed Act as eliminating "competitive market forces" by placing market power in the hands of the Producers allowing them to control when and how a pipeline can be built. Additionally, Foothills asserts that the ANGTA is consistent with a market based approach because it allows commercial negotiations between the producers of gas and pipeline owners for tariff terms and conditions.

Further, the Proposed Act, unlike the ANGTA, does not guarantee that Alaskans will have access to gas produced from Alaska's lands for use in-state. Section 13(b) of the Alaska Gas Act provides:

> "The State of Alaska is authorized to ship its royalty gas on the approved transportation system for use within Alaska and, to the extent it contracts for the sale of royalty gas so provide, to withdraw such gas from the interstate market for use within Alaska; the [Federal Energy Regulatory Commission] shall issue all authorizations necessary to effectuate such shipment and withdrawal ...."

The Proposed Act has no similar provision.

This Section Analysis will briefly describe each section of the Proposed Act. It will also contrast the Proposed Act with the ANGTA and highlight some of the criticisms expressed by other interested parties.

II. Section by Section Summary

Section 1. Short Title.

The Proposed Act is named the "Alaska Natural Gas Pipeline Act of 2001."

Section 2. Congressional Findings.

This section sets forth the proposed findings of Congress to justify the Proposed Act. Findings (1) –(6) are uncontroversial setting forth the need for gas in the Lower 48 and a short history of the ANGTA.

Finding (6) states that despite the passage of more than twenty years, the parties seeking to develop the Alaska portion of the ANGTA project have been unable to obtain the necessary regulatory approvals or attract the necessary financing. This finding leads the Producers to claim that the ANGTA effort is a "failure." Others claim that Finding (6) is misleading because Foothills has obtained many authorizations and financing could not be obtained primarily because the Producers were unwilling to commit their reserves to the project due to market conditions.

Finding (7) states that because of the passage of time, some of the design features of the ANGTA system are outdated and would have to be modified. Although the statement is true, it implies that these modifications cannot be obtained under ANGTA. Foothills has submitted numerous briefing materials that such modifications can be obtained.

Finding (8) states that because of a change in the nation's energy supply situation, interest in an Alaska project has been renewed. This Finding, as well as the entire Proposed Act, has been criticized for ignoring a LNG option. The Port Authority presented the Committee with a draft bill in Fairbanks that incorporated an LNG option.

Findings (9) and (10) suggest that in order to assess economic certainty, one must know whether permits and environmental assessment can be timely obtained. Foothills asserts that these findings ignore the ANGTA's provisions regarding expedited permitting, limits on agency discretion, and limits on judicial review, which provide more certainty than any other federal statute.

Section 3. Congressional Statement of Purpose

This section sets forth the Proposed Act's purposes. As noted in the Overview Section above, the purpose is expedite the construction of a transportation system for Alaska natural gas to the lower 48 by relying on market forces and by providing measures to expedite necessary approvals. Again, the Proposed Act's purpose is similar to the ANGTA's purpose.

Section 4. Definitions.

This section defines various terms used throughout the Proposed Act. Most are non-controversial. Some are not.

Section 4(5) appears to limit the markets to which Alaska gas can be transported to "Lower 48 Markets." If so, this would exclude Alaska and Canadian markets. Similarly, Sections 4(6) and (7) only address facilities to be built in Alaska and the Lower 48 States. They do not address Canadian facilities. The ANGTA, on the other hand, did address Canadian facilities and, indeed, the coordination of United States and Canadian facilities were addressed in a treaty and another agreement with Canada. Foothills suggests that the Proposed Act "could create confusion and significant lack of coordination between the two countries on regulatory and commercial issues." Additionally, the definitions exclude an LNG option through Alaska. One commentator asks: if we are looking at new approaches why exclude the LNG option.

Section 5. Expedited Approval Process.

Section 5(a) adds new definitions to the Natural Gas Act (NGA), which is the federal law that generally governs construction and operations of pipelines and which is administered by the Federal Energy Regulatory Commission (FERC). Subject to the comments made in Section II.4. above, most of the definitions are non-controversial.

Section 5(b) amends the NGA to provide that FERC **shall issue** a certificate of public convenience and necessity to a firm to construct and operate the Alaska portion of a pipeline if three conditions are met. They are:

1. FERC determines that the applicant has contracted with a "Shipper" to transport some Alaska natural gas to Lower 48 Markets;
2. FERC determines that rates, terms and conditions for transportation services **can be established** under the Natural Gas Act; and
3. FERC determines that the terms and conditions for compliance with all applicable environmental laws **can be established** in accordance the Natural Gas Act.

To help expedite the process, Section 5(b) requires that the FERC makes these determinations and issue a certificate within 18 months after the filing of an application. Finally, section 5(b) adds a new section to the NGA authorizing the FERC to issue a certificate to transport Alaska gas from the Canadian border to the Lower 48 through normal NGA procedures.

The Department of Law's outside counsel, Morrison & Forestor (MoFo), and Foothils have suggested that, upon finding that these three conditions exist, FERC must issue a certificate. MoFo has suggested that FERC has no other discretion. Along the same lines, Foothills suggests that the Proposed Act would eliminate the NGA's requirement that an applicant demonstrate "public convenience and necessity."

The Proposed Act requires a contract with a "Shipper," who the Producers define as "anyone who, through contract or otherwise, controls Alaska Natural Gas", before an application can be submitted. MoFo and others have also suggested that this requirement gives the Producers a significant leg up on any other potential applicant because they already "control" the gas. Foothills and other commentators believe that giving the Producers too much control raises antitrust concerns.

Foothills also contends that the "can be established" language is designed to allow the applicant to catch up with the ANGTA's clear regulatory headstart. Under the NGA, Foothills says that rates, terms, and conditions are reviewed to insure that the public convenience and necessity standard is satisfied before, not after, a certificate is issued.

Section 6. Environmental Reviews

Section 6 requires a single environmental impact statement (EIS) for the Alaska to Alberta portion of the project and a single EIS for the Alberta to the Lower 48 portion. It

designates the FERC as the lead agency and provides that an EIS shall be prepared in accordance with the FERC's regulations and procedures. It further states that such an EIS shall satisfy the National Environmental Policy Act (NEPA) obligations of each federal agency whose approval is required for the project. The scope of an EIS shall be limited to the scope of the application. The preparation of an EIS shall be expedited, the draft shall be issued within twelve months after the filing of the application and the final EIS shall be issued within six months thereafter absent good cause.

Foothills and others assert that section 6, in combination with the mandatory provisions of Section 5, can be interpreted to eliminate the NEPA's requirement to evaluate alternative routes and to eliminate the "no action" alternative **before** issuing a certificate. Further, Foothills argues that FERC could be required to issue a certificate for an Over the Top route even though there are more environmentally acceptable alternatives.

Finally, Foothills notes that two EISs and a supplemental EIS has already been prepared for the ANGTA project. These reviews were prepared and concluded after numerous opportunities for public review and comment. Congress found that those EISs satisfied NEPA.

Section 7. Federal Pipeline Director

Section 7 creates the Office of the Federal Pipeline Director within the executive branch. The Director is responsible for coordinating expeditious action, study, review and compliance with the Proposed Act by all federal agencies. Upon a written agreement, an agency may delegate any of its duties regarding the Alaska Gas Project to the Director. Section 7 requires the Director to report semi-annually to Congress on the status of the project and authorizes appropriations for the Director's office.

Section 7 basically duplicates the provisions of ANGTA that created the Office of the Federal Inspector. That position was later abolished by Congress, but the functions were transferred to the Secretary of Energy.

Section 8. Agency Reviews and Decisions

Section 8 requires that all actions take by federal agencies be expedited and their actions be coordinated under the direction of the Director. Any necessary authorization for the Alaska Gas Project may include terms and conditions permitted by law unless the Director determines that they would impair the expeditious construction and initial operation system to transport Alaska gas. Section 8 is basically the same as Section 9(a) of the ANGTA.

Section 9. Judicial Review

Section 9 limits review of a federal agency's action in connection with the Alaska Gas Project to claims that the action violated the Constitution or was in excess of statutory authority. It also limits the time within which an action can be brought. Claims that the action were arbitrary and capricious are precluded. Section 9 requires that all claims be brought exclusively in the D.C. Circuit Court and that the court treat all claims as a

matter for expedited consideration. Section 9 of the Proposed Act is similar to Section 10 of the ANGTA.

Section 10. Separability

Section 10 provides that if any provision of the Proposed Act is invalid, the remainder of it is unaffected. This section is the same as Section 16 of the ANGTA.

Foothills Pipe Lines Alaska, Inc.

September 5, 2001

FAX: 907-260-3044

Senator John Torgerson
Alaska State Legislature
35477 Kenai Spur Highway, Suite 101 B
Soldotna, Alaska 99669

Dear Senator Torgerson:

At the August 15 meeting of the Joint Committee on Gas Pipelines held in Fairbanks, you requested I provide the Committee with more detailed comments on the producers' proposed legislation.

Attached is a sectional analysis of that proposed legislation which we would be happy to discuss with you at your convenience.

Yours very truly,

John Ellwood
Vice President

JRE:js
Attachment

3100 - 707 EIGHTH AVENUE S.W., CALGARY, ALBERTA T2P 3W8 (403) 294-4111 FAX (403) 294-4171

ANALYSIS OF
THE "ALASKA NATURAL GAS PIPELINE ACT OF 2001" (ANGPA)
AND
COMPARISON TO
THE ALASKA NATURAL GAS TRANSPORTATION ACT (ANGTA)
AND
THE NATURAL GAS ACT (NGA)

SUMMARY

In ANGPA the producers have in many respects created a duplicate of ANGTA. ANGPA's stated purpose is to expedite the approval and construction of an Alaska natural gas pipeline. This is identical to the purpose of ANGTA ("to provide the means for making a sound decision as to the selection of a transportation system for delivery of Alaska natural gas to the contiguous states ... to expedite its construction and initial operation .... Sec. 3 of ANGTA). ANGPA copies, almost verbatim, many of the provisions of ANGTA that provide for expedited permit approval, limits on agency discretion and limits on judicial review.

There are two fundamental differences between ANGPA and ANGTA. First, ANGPA seeks to rely on "competitive market forces" to determine which pipeline can be built and operated in the most economic manner. The actual effect of ANGPA may well be to concentrate market power in the hands of the producers. In contrast, Congress enacted ANGTA specifically to terminate the jockeying among the various commercial interests that threatened to delay expeditious construction. However, ANGTA is consistent with a market based approach in that it allows for commercial negotiations between the gas owners and the holders of the certificates for the pipeline within the framework of ANGTA regarding ownership, governance, tariff terms and conditions as well as rates for transportation services.

Second, by approving the selection of the ANGTS project under ANGTA, Congress determined that ownership and control of the pipeline for Alaska gas should be independent of ownership and control of the gas resources. Enactment of ANGPA would reverse this determination by vesting in the North Slope gas producers total control over when, where and by whom a pipeline is constructed as a matter of law. Contrary to the assertions of the producers, under ANGTA, the producers maintain significant control over when a pipeline is constructed and the rates, terms and conditions for transportation of the gas, by virtue of their ownership of the gas, but they cannot exercise complete control because of the involvement of independent owners such as pipeline companies.

By placing total control in the producers hands, ANGPA, if enacted, would render meaningless ANGTA and the actions of five previous U.S. Administrations and multiple Congresses.

SECTION BY SECTION ANALYSIS AND COMPARISON

ANGPA Section 2(3)

Finds that, despite the passage of more than 20 years, the Alaska Natural Gas Transportation System (ANGTS) has been unable to obtain the regulatory approvals or attract financing to permit the construction of the project.

ANGTA

- ANGTS has obtained several of the needed regulatory approvals for the project, including a conditional certificate of public convenience and necessity from FERC, Clean Water Act Section 404 wetlands permits from the Corps of Engineers and a right of way across all federal land in Alaska from the BLM.

- In Canada the ANGTS has obtained conditional Certificates of Public Convenience and Necessity as well as right of way across the entire Yukon Territory.

- The ability to attract financing is directly related to the producers' willingness to commit their gas reserves to a pipeline project. The producers have been unwilling to do this for more than 20 years because of gas market economics.

- ANGTA has no sunset provisions and neither the Natural Gas Act (NGA) nor the Canadian Northern Pipeline Act (NPA) certificates contain expiration dates.

ANGPA Section 2(7)

Finds that as a result of the passage of time, some design features mandated for the Alaska to Alberta section of the ANGTS would have to be modified to take full advantage of current technological capabilities, and other changes also may be needed to ensure an economically, environmentally, and technically sound approach.

ANGTA

- Original design features of the ANGTS definitely will need to be changed to reflect modern technologies. However, contrary to the implications of ANGPA's language, Section 9(d) of ANGTA specifically authorizes amendments to certificates and permits which would allow updating of the ANGTS to take into account economic, environmental, regulatory, tariff and technical changes, so long as the "basic nature and general route" of the project are not changed. (The "nature and route" of the system is set forth in Section 2 of President's Decision, dated September 22, 1977.)

- Section 10(b) of the international agreement with Canada (the Agreement on Principles) specifically recognizes the need for flexibility with respect to the design of the physical facilities and creates a Technical Study Group to advise FERC and the Northern Pipeline Agency in Canada on their determinations as to the most economical and efficient pipeline design.

- Moreover, Foothills' system in Alberta has been expanded numerous times pursuant to the NPA demonstrating the flexibility and adequacy of the ANGTS framework.

- The ANGTS sponsors have prepared several detailed issue papers which address this issue, among others. Copies of such papers will gladly be provided upon request.

ANGPA Section 2(10)(II)

Finds that it is in the national interest to provide as much regulatory certainty and expedition as practicable for approval and implementation of any proposals to enhance the prospects of economic viability and development.

ANGTA

- Through its expedited permitting provisions, limits on agency discretion and limited judicial review, ANGTA provides more regulatory certainty and expedition than any other federal statute currently in existence. (See for example, Section 3 of ANGTA which provides in part "To accomplish this purpose [to expedite construction and review] it is the intent of the Congress to exercise its constitutional powers to the fullest extent in the authorizations and directions herein made, and particularly with respect to the limitations of judicial review of actions of Federal officers or agencies taken pursuant thereto.")

ANGPA Section 2(10)(iii) and (v)

Finds that it is in the national interest to allow for the possibility that the market may support now or in the future the construction of more than one transportation system and to encourage the development of one or more pipeline systems.

ANGTA

- The purpose of ANGTA is to ensure that at least one pipeline is built. However, ANGTA is not exclusive for all time. It provides a priority right to the ANGTS to construct a pipeline. After that pipeline is constructed and in initial operation the provisions of ANGTA will have been fulfilled and other pipelines may then be built, if the market will support them.

- Contrary to the structure of ANGPA, such decisions on future pipelines would, under ANGTA and the NGA, involve input from public authorities and consideration of other public policy factors – not just who can obtain a contract to control Alaska natural gas.

ANGPA Section 3

Declares that the purpose of ANGPA is to expedite the approval, construction and initial operation of one or more transportation systems for the delivery of Alaska Natural Gas to the Lower 48 States by:

- relying on competitive market forces to determine which system(s) can be built and operated in an economically viable manner;
- providing for the expedited review and approval of applications for a FERC certificate and related federal approvals for one or more pipelines;
- ensuring the full consideration of environmental impacts and related concerns, consistent with the need to expedite the review of the proposed project(s);
- creating an Office of Federal Pipeline Director to direct the efficient and coordinated participation of, and decisionmaking by, the various federal agencies;
- expediting the resolution of, and limiting the jurisdiction of the courts to review disputes concerning any aspect of the ANGPA or the approval process for any project.

ANGTA

- The purposes and provisions of ANGTA are identical to those for ANGPA. Indeed, Congress enacted ANGTA to provide a detailed procedure to make a "sound decision" between several competing projects. That "sound decision" resulted in the selection of the ANGTS. ANGTA then provides, with respect to the ANGTS, for expedited permitting, coordinated federal review of construction and limited judicial review.

ANGPA Section 4(6) and (7)

Defines and includes within its scope only the U.S. portions of a pipeline through the defined terms "Alaska Facilities Gas Project" and "Lower 48 Facilities Gas Project" or collectively "Alaska Gas Project". ANGPA does not define or include within its scope the Canadian portions of an Alaska gas pipeline.

ANGTA

- ANGTA addressed the Canadian portions of the pipeline by directing the President to consult with the Government of Canada. Pursuant to this direction, the President reached an international agreement with Canada to ensure that the Canadian portions of the pipeline would be constructed in a manner and timeframe consistent with the U.S. portion.
- Expedition and coordination of necessary regulatory and commercial issues with respect to the Canadian facilities is enshrined in the bilateral Agreement on Principles and the Canadian act of Parliament, the NPA. Development of a new regulatory regime in the United States, such as ANGPA, could create confusion and significant lack of coordination between the two countries on regulatory and commercial issues.

ANGPA Section 5(b)

Amends Section 7 of the NGA to mandate that, notwithstanding any other provision of law, FERC issue a certificate for the construction of an Alaska gas pipeline where:

1) the applicant has an agreement with a "shipper" of Alaska gas for the transportation of such gas on behalf of the shipper with the intent that all or a portion of such gas will ultimately be delivered to the lower 48;
2) FERC determines that the rates, terms and conditions of transportation can be established according to the procedures in existing NGA Section 7(e); and
3) the terms and conditions for compliance with all environmental laws applicable can be established in accordance with NGA Section 7(e).

The Commission would be required to make these determinations and issue a certificate within 18 months of a filing.

For purposes of the provision, "shipper" is defined as anyone who has an agreement with a person who is or will become a holder of a FERC certificate for the construction of an Alaska gas pipeline.

Pursuant to the provisions of ANGPA, an applicant has a qualified project only if the applicant has reached agreement with a shipper of Alaska Natural Gas. Therefore, before an applicant can file, its shipper appears to have to obtain control over some amount of Alaska Natural Gas. If this sequence is in fact how the ANGPA process is intended to work then the owners of Alaska Natural Gas will be able to confer upon a favored applicant mandatory entitlement to the statutory benefits of ANGPA with no

independent evaluation by any public entities. Thus, all the producers need to do to acquire a FERC certificate is create a transportation company (ala Alyeska), sign an agreement with that company for the transportation of Alaska gas, and have that company file an application with FERC. FERC would be required to issue a certificate to that company.

ANGTA

- Section 5 of ANGPA does not repeal or otherwise directly affect ANGTA. However, ANGPA would directly override the previous determination made by Congress in approving the ANGTS project that ownership and control of the transportation system for Alaska gas should be independent of the ownership and control of the gas reserves.
- While the original prohibition on producer equity participation was relaxed pursuant to a Presidential request for Waiver of existing law, such waiver still provided for review of any producer equity participation by the Justice Department.
- This antitrust review would disappear under ANGPA.
- In this regard, because ANGPA directs the FERC to issue a certificate, notwithstanding any other provision of law, it renders the FERC certificate that the ANGTS received under ANGTA potentially meaningless. Since the producers can limit through their contracting practices who is eligible to apply for a certificate under ANGPA, they have absolutely no need or incentive to enter into an agreement with the ANGTS.
- The "can be established" statutory languages applicable to the second and third criteria appear designed to catch up with the ANGTS' clear regulatory head start.

NGA

- For an Alaska gas pipeline, ANGPA eliminates the NGA requirement that a pipeline demonstrate "public convenience and necessity" in order to receive a certificate for construction. If the applicant meets the three criteria, the project would be presumed to be in the public convenience and necessity and the Commission would be required by law to issue a certificate.

- The "can be established" threshold for meeting the second and third criteria is a significant departure from the NGA. If the Commission determines that rates, terms and conditions for transportation and the terms and conditions for compliance with environmental laws can be established it must issue the certificate. Under normal NGA procedures the proposed construction and services itself, including rates, terms and conditions of transportation service, are reviewed to make sure that such proposals satisfy the NGA's public convenience and necessity standard. Thus, ANGPA provides for the mandatory issuance of a preliminary certificate which the producers could then hold without completing the latter compliance procedures. The result would be that no one else could move forward with a pipeline and the producers could tie up development of the gas reserves.

ANGPA Section 6

This section provides that two separate EISs will be prepared (one applicable to the Alaska facilities, including any conditioning plant, and one applicable to any Lower 48 facilities) prior to the issuance of any certificate of public convenience and necessity. The section also directs that FERC would be the lead agency for the EISs and that such EISs will satisfy the NEPA obligations of each federal agency whose approval is required. It requires that the preparation of the EISs be expedited, that the draft EIS be issued within 12 months after the application is filed, and the final EIS be issued within 6 months thereafter, unless the Commission determines that additional time is needed to comply with environmental or other laws. Last, this section provides that the scope of any EIS shall correspond to the scope of the applicable certificate application.

This provision, in conjunction with the mandatory requirement to issue a certificate, can be interpreted to eliminate the need for an evaluation of alternative routes to the route proposed by the applicant and to eliminate an evaluation of a "no action" alternative. Even if that is not the case, FERC would not be required to take into account the EIS or its alternative findings, when it makes its determination that terms and conditions for compliance with all environmental laws can be established in accordance with NGA Section 7(e). Thus, FERC could be required to issue a certificate for an over the top route even though there may be more environmentally acceptable alternatives.

ANGTA

- Two EISs and a Supplemental EIS have already been prepared for the ANGTS project. These environmental review documents were prepared and concluded after numerous opportunities for public review and comment. Congress found those EISs to be sufficient to satisfy NEPA. The ANGTS sponsors have prepared a detailed policy paper on the environmental review process applicable to the ANGTS pursuant to the ANGTA regime. A copy will gladly be provided upon request.

NGA

- Under the NGA, any EIS for a proposed project would, in accordance with NEPA, include a review of alternatives, including the alternative of "no action." FERC is required to consider the findings of the EIS before making a decision on whether to grant the certificate.

ANGPA Section 7

This section establishes an Office of Federal Pipeline Director (OFPD) within the Executive Office of the President. The Director would be appointed by the President, with advice and consent of the Senate. The Director's responsibilities would include coordinating:

- the expeditious discharge of all federal agency activities;
- the compliance by all federal agencies with the provisions of the ANGPA, including serving as a "one window point" for filing and issuance of all necessary permits, certificates, grants, or other authorizations,
- the expeditious completion of all environmental and other studies and reviews of any kind that are required or conducted for a Alaska Gas Project.

In addition, the head of any federal agency may delegate to the Director any statutory function vested in such agency, including permitting functions.

This section duplicates the provisions of ANGTA which created the Federal Inspector for construction of the ANGTS.

ANGTA

- ANGTA established the Federal Inspector for the construction of the ANGTS. The Federal Inspector possessed many of the same functions and authorities of the proposed Federal Pipeline Director. The Energy Policy Act of 1992 abolished the Federal Inspector position but transferred all of the functions and authorities of the Inspector to the Secretary of Energy.

NGA

- There is no comparable provision in the NGA.

ANGPA Section 8

This section requires that all actions by any federal officer or agency with respect to an Alaska Gas Project be expedited so as to meet the deadlines set forth in the ANGPA. In addition, there is an affirmative obligation on any federal officer or agency involved in the review or approval process to cooperate and coordinate with one another, under the directions of the Federal Pipeline Director, to expedite decisionmaking and to minimize duplication of effort.

This section also prohibits agencies from imposing terms or conditions in any certificate or permit that could prevent or impair in any significant respect the expeditious construction and initial operation of the project.

This provision is nearly identical to the expedited permitting and limits on agency discretion provisions of ANGTA.

ANGTA

- Section 9 of ANGTA:
  1) directs federal agencies to issue all permits, authorizations and certificates at the earliest practicable date;
  2) directs that all applications for permits and authorizations for the ANGTS be expedited and be given precedence over any other applications;
  3) prohibits federal agencies from imposing any terms or conditions that would change the basic nature and general route of the ANGTS or prevent or impair in any significant respect the construction and initial operation of the ANGTS.

NGA

- There is no comparable provision in the NGA.

ANGPA Section 9

This section limits the ability of any person to bring a lawsuit to challenge the actions taken by federal agencies with respect to any Alaska Gas Project. The only claims that can be made are those that challenge the validity of the ANGPA; allege that an agency action will deny rights under the Constitution; or allege that an agency action exceeds the agency's authority.

ANGTA

- Section 9 of ANGPA is identical to Section 10 of ANGTA in all material respects.

CONCLUSION

While ANGPA is duplicative of ANGTA and does not repeal or amend ANGTA, it would have the effect of eliminating or reversing several of the benefits of ANGTA:

1) It reverses the Congressional judgment that ownership and control of the transportation system for Alaska gas should be independent of the ownership and control of the gas reserves by vesting in the producers total control of when, where and by whom a pipeline is constructed.
2) It eliminates the previous determination by Congress that the Alaska Highway Route is the best route economically and environmentally for the pipeline.
3) In the event a project other than the ANGTS is authorized, it would effectively nullify the existing international agreement with Canada and would require negotiation of an entirely new agreement which agreement cannot be taken for granted. Indeed, any new agreement and resulting Canadian legislation may not produce results as favorable as those under the ANGTA regime.
4) It undercuts the value of the certificates, permits and rights of way granted to the ANGTS project under ANGTA.

ANGPA also changes the standard procedure under the NGA by

1) circumscribing FERC's authority to fully evaluate the rates, terms and conditions for the transportation service and the environmental impacts of the proposed project before making a determination of public convenience and necessity and removing any discretion on the part of FERC.

What we would like

Fair access at a reasonable price.
A level playing field.
Open process and disclosure.

Concerns

Open Season
Disclosure of bidding terms and capacity award procedures.
Disclosure of project specifications and tariff.
Reasonable amount of time to evaluate terms and conditions before open season.
Capacity not held back.
NGL ownership remains with shipper.
Reasonable Btu minimums for gas entering pipeline.

Tariffs
Based on Btu not volume.
Mileage based.
Accelerated depreciation doesn't increase tariffs.
Gas conditioning costs unbundled or not included in tariff.
Rate caps on released capacity.

Pipeline Expansion
No discrimination based on pipeline ownership or initial capacity awards.
Anticipated tariff rate changes and access for expansion.
Multiple connection points and delivery options.
Assurance that pipeline will be expanded if reasonable conditions are met.

Discussion Paper For Any Proposed Legislation Concerning An Alaskan Natural Gas Pipeline

DRAFT 8/24/01

SECTION I – INTRODUCTION / SUMMARY OF ISSUE

Background / Why Construction of an Alaska Gas Pipeline is Vital

Construction of a proposed pipeline that would carry Alaskan natural gas to the Lower 48 markets is extremely important to America from several standpoints.

Demand for energy is rising rapidly in the U.S., and America is facing a long-term shortage of natural gas. A pipeline that would allow the Lower 48 states to tap Alaska's plentiful natural gas reserves would help ensure that America as a whole has adequate supplies of gas at reasonable prices.

It also is critical to the state of Alaska, for four reasons:

One, construction of a multi-billion-dollar natural gas pipeline would generate an enormous amount of new capital investment and job creation in the state of Alaska.

Two, it would allow the state to provide its own citizens with access to natural gas. Currently, only residents of the South Central area and Barrow have natural gas service. Fairbanks does not have access to gas services.

Three, it would allow the state as a royalty owner to realize the benefit of monetizing natural gas reserves associated with major oil fields on the North Slope that have lain untapped for nearly three decades.

And four, it would allow Alaska to realize the economic benefits of continuing energy activity in the state by encouraging exploration of new, yet-to-be-discovered reserves of natural gas elsewhere in Alaska.

Needs of All Potential Shippers on the Alaska Gas Pipeline

For energy companies considering exploration ventures in Alaska that specifically target "new" natural gas, access to a pipeline is critical. If producers cannot be assured of fair and reasonable access to space on a pipeline to carry enough new gas to market to make their projects economic, they will not explore. As a result, the state of Alaska will lose the benefits of capital investment and job creation that those new exploration projects would bring.

For these reasons, it is vital that any new legislation enabling the expedited construction of a new pipeline from the Slope to the Lower 48 take into account *not only* the transportation capacity needs of North Slope producers who want to begin marketing and monetizing existing gas reserves from Prudhoe Bay, Point Thompson and other declining oil fields, ***but also*** the needs of companies holding access to acreage that is prospective for natural gas exploration and development in the future.

It is in the best interests of – and the stated policy goal of – the state of Alaska to encourage greater competition among a larger number of companies exploring for new reserves in Alaska.

In light of these issues and economic concerns that impact both the state of Alaska and companies exploring for "new" gas in Alaska, any bill enacted to enable expedited construction of an Alaska natural gas pipeline should contain certain provisions to ensure those interests and concerns are addressed fairly. These provisions should ensure that companies who are exploring for yet-to-be-discovered gas fields are not denied access to the proposed pipeline by its owners, or granted access under terms that would render their development projects uneconomic.

Summary of Shippers' Concerns and Potential Competitive Barriers

Following is a brief summary of some of the most significant concerns about competitive barriers:

Access

As both the owners of 90 percent of the existing proved natural gas reserves on the North Slope and of the proposed pipeline, the three-company pipeline ownership group could use this de facto monopoly power to:

- greatly restrict pipeline access to non-owner producer/shippers through capacity "hold backs";
- make transportation capacity either completely unavailable or unreasonably expensive to shippers who are not able to secure firm capacity under the initial "open season" bidding;
- force shippers who are unable to obtain transportation capacity at reasonable prices to sell their "stranded" gas at distressed prices to those that control the firm transportation; and
- delay or completely forestall a pipeline expansion that would provide needed pipeline capacity for competing producers who have made major new gas discoveries.

Contract Tariffs

Shippers who are not part of the ownership group risk paying unreasonably high tariffs due to a number of conditions, including:

- the potential inclusion of accelerated depreciation by the pipeline ownership group;
- the "bundling" of unnecessary ancillary services such as CO_2 conditioning into the standard tariff rate;
- charging full fare to those shippers who inject gas downstream of the pipeline's origination point near Prudhoe Bay or offload it to local markets in Alaska, rather than charging a lower, mileage-based tariff; and
- computing tariff rates on a volumetric basis rather than a heating value basis, which would result in leaner "new" gas subsidizing richer gas with a higher Btu content found at existing fields.

Other Tariff Terms and Conditions

Pipeline owners could put non-owner producer/shippers at a commercial disadvantage – or keep their gas off the pipeline entirely, by:

- requiring non-owner producer/shippers to forfeit their rights to natural gas liquids extracted from their gas streams; and
- setting strict pipeline quality standards that would prevent lower-Btu gas from entering the pipeline.

These issues and others are more fully discussed in the following pages in Section II:

SECTION II – DISCUSSION OF CONCERNS OF AND COMPETITIVE BARRIERS TO SHIPPERS WHO ARE NOT PIPELINE OWNERS

Background / Alaska Gas Pipeline Project Scope

The natural gas pipeline required to deliver Alaska natural gas reserves to Western Canada and the U.S. Lower 48 States is a massive undertaking. It is anticipated that a 1,800-mile, large-diameter pipeline with an initial capacity of about 4 billion cubic feet a day (Bcf/d) will need to be constructed to Alberta, Canada. In addition, it is assumed that another 1,800 miles of new pipeline of somewhat smaller diameter will have to be installed from Western Canada to markets in Eastern Canada, the U.S. Midwest and U.S. Pacific Coast, because existing pipelines will not have sufficient excess capacity to transport all of this new Arctic gas supply to market centers.

Including the cost of a gas conditioning plant and the anticipated need for new pipeline facilities all the way to U.S. market centers (e.g. Chicago), recent estimates set the total costs for this Alaska gas pipeline project in the $15 billion to $20 billion range.

The 1,800-mile Alaska-to-Alberta portion of the pipeline alone will be the largest, most expensive pipeline project ever undertaken. Cost estimates for this portion of the project, excluding ancillary services such as gas conditioning, run in the $7 billion to $10 billion range.

Nature of the Pipeline Ownership Group

The existing North Slope reserves anchoring the proposed pipeline are predominately held by three major integrated oil companies – BP, Exxon-Mobil and Phillips – the same group that likely would construct and own the gas pipeline. These three majors own more than 98 percent of the gas reserves in the giant Prudhoe Bay Unit and nearly 80 percent of the gas reserves in the second-largest North Slope gas accumulation, the Point Thomson Unit. Together, these two fields represent more than 30 trillion cubic feet (Tcf) of the 35 Tcf of proved ANS gas reserves.

In addition, BP, Exxon-Mobil and Phillips own the overwhelming majority of the remaining ~ 5 Tcf of proven gas reserves attributable to the other North Slope oil and gas fields. These three companies control more than 90 percent of the proven North Slope gas reserves.

Competitive Concerns of Shippers Outside the Pipeline Owners' Group

This dominant market position held by BP, Exxon-Mobil and Phillips poses a competitive concern to other natural gas explorers in northern Alaska. As owners of practically all of the

proved Alaska gas reserves – and as sponsors of the proposed Alaska gas pipeline – these three companies have the power to control future exploration for and development of new gas resources in Alaska. If other explorers cannot be assured of fair access to a pipeline to carry their production to market, they will not explore, because their potential discoveries would be stranded in Alaska.

Exxon-Mobil, BP and Phillips have undertaken a detailed, $100 million study to determine the economic feasibility and appropriate routing for the Alaska gas pipeline. The feasibility study is scheduled to be completed by the end of 2001.

Market Concentration Issues

With more than 90 percent of the natural gas reserves concentrated among three producing companies, these companies have the opportunity to wield de facto monopolistic market power through their ownership and control of the proposed pipeline. This puts companies exploring for "new," yet-to-be-discovered reserves of North Slope natural gas at a decided disadvantage.

Access to the Alaska gas pipeline is of paramount importance to explorers, because without access to a pipeline to carry gas to markets, their gas discoveries will be virtually worthless. If Exxon-Mobil, BP and Phillips are able to secure all of the pipeline capacity in the proposed Alaska gas pipeline, explorers who are shut out of the pipeline initially will have three alternatives, none of which are commercially advantageous or attractive to them.

They may (1) wait for spare capacity to open up after Prudhoe Bay and Point Thompson have declined; (2) seek released capacity from the shippers that secured the initial capacity; or (3) sell gas from their discoveries at distressed prices to the holders of the pipeline capacity.

In the first case, gas reserves and expected production rates from the Prudhoe Bay and Point Thomson units will likely keep a 4 Bcf/d pipeline full for approximately 20 years. In addition, BP and Phillips each hold huge acreage positions from which they are expected to be able to replace Prudhoe Bay and Point Thomson production declines with new discoveries. Therefore, if the three dominant gas reserve holders secure all of the initial pipeline capacity, it is likely that they will be able to keep the pipeline full with their own equity production for decades, and new gas explorers will be shut out indefinitely.

Gaining access to the pipeline at a future date by securing capacity from existing shippers poses a commercial risk to new gas explorers. FERC Order 637 allows shippers who release capacity to others to charge tariffs that are higher than the maximum allowed by FERC as part of the

initial contract process. Similarly, capacity holders could offer to buy the other explorers' "stranded" gas at distressed prices.

Explorers need look no further than a recent episode in Western Canada for an example of how holders of transportation capacity can drive down wellhead prices during periods when pipeline capacity is in short supply.

During 1996, Western Canadian gas prices averaged just $1.03 per million Btu (MMBtu), while U.S. gas prices averaged $2.51 per MMBtu (at Henry Hub, Louisiana). Western Canada prices should have averaged closer to $1.80 per MMBtu, based solely upon transportation differentials. However, pipeline capacity out of Western Canada was constrained and, as a result, Western Canadian gas prices were more than 40 percent lower than they should have been based on transportation cost differentials. Companies holding the scarce pipeline capacity reaped a nearly 75-cent per MMBtu windfall. This windfall represents 70-75 percent of the wellhead prices realized. In other words, holders of the pipeline capacity required to market the gas realized almost as much for transporting this Canadian gas as the producers who explored for and developed the gas realized.

The same three major integrated oil companies structured and operated the Trans-Alaskan Oil Pipeline (TAPS) to the detriment of second-tier companies, effectively driving several companies out of Alaska during the '80s and '90s. Conoco openly cited this as the reason it decided to halt exploration and production in Alaska. The company sold its properties at distressed prices and exited Alaska entirely.

The remote location of the Alaskan North Slope effectively creates a natural monopoly for the pipeline owners and firm capacity holders. The magnitude and cost of the project represent very real barriers to entry. In all likelihood, there will never be another gas pipeline built from Alaska to Western Canada and the Lower 48 states. To justify another pipeline, an additional 30 Tcf of reserves would have to be discovered and proven up.

In reality, it is extremely unlikely that petroleum companies would spend the money to prove up another 30 Tcf to justify a second, competing pipeline. It has taken more than 20 years for sufficient economic momentum to develop to drive the probable construction of the first pipeline.

Therefore, the dominant producers – BP, Exxon-Mobil and Phillips – are in a position to enjoy not only monopolistic power over the Alaska gas pipeline, but by extension, to limit future exploration and production by other companies.

The "Open Season" Process and Oversight

FERC requires that any one who wants to construct an interstate natural gas pipeline must first file an application for a "certificate of public convenience and necessity." This certificate is to ensure that there will be sufficient demand by potential shippers to justify the public disruption of laying a pipeline and to ensure that the organization building the pipeline, or the "sponsor," will have enough volume from paying shippers to be economically successful.

To gauge initial shipper interest, a sponsor will first make a public announcement about its plans to construct a new natural gas pipeline. The announcement will include details on the location, length and capacity of the project, and when the open season will occur. If shipper response to this initial announcement is strong, the sponsor will take the next step of conducting an "open season" and signing up shippers for transportation service through "precedent agreements." The sponsor will then present these precedent agreements to FERC as evidence of sufficient market demand for its project.

"Non Discriminatory, Open Access" Is a Misnomer

There is a common misconception that, as an interstate natural gas pipeline governed by the Federal Energy Regulatory Commission's non-discriminatory, open-access mandate, access to the pipeline by all comers is guaranteed. In the case of the proposed Alaska pipeline, it is not.

FERC-regulated natural gas pipelines are generally known as "contract carriage" pipelines. Under such a regime, shippers contract for capacity to the pipeline. In areas with little or no direct competition, most, if not all of the capacity, is contracted for on a firm basis for extended periods, such as 10 or 20 years. Once the capacity has been fully subscribed, only interruptible capacity, or capacity that is sublet by firm shippers, is available to parties unable to secure firm capacity at the outset. The firm capacity holders are allowed to charge whatever tariff the market will bear for released capacity.

This "contract carriage" system of capacity allocation differs greatly from the standard "common carrier" method generally used for oil pipelines. Capacity on a common carrier pipeline is always allocated on a pro rata basis. If shippers tender more oil to the pipeline than there is capacity, then all shippers, both existing and new, are prorated, giving each shipper a proportionate share of the pipeline capacity.

If explorers for new gas don't reserve capacity on the Alaska gas pipeline during the initial open season, they run the risk of not being able to secure any transportation capacity once they do make a discovery, because the existing gas reserves from Prudhoe Bay and Point Thompson could theoretically keep a 4 Bcf pipeline full for 20 years. Or if they could gain access to the line after the initial open season from a holder that sublets his firm transportation rights, they risk having to pay excessive tariffs – or having to sell their stranded gas at depressed prices to the companies that hold the firm pipeline capacity.

On the other hand, if new entrants into Alaska do reserve space on the pipeline before they make any discoveries – and if they are not successful in finding new gas reserves to put into the pipeline quickly – they would be forced to pay potentially tens or even hundreds of millions of dollars a year for unneeded capacity.

Generally, the open season process is either lightly regulated or not regulated at all. Two concerns of new gas explorers is that the pipeline sponsors will not give potential shippers and other stakeholders enough information on the operational and commercial characteristics of the pipeline, and shippers will not receive this information far enough in advance of the brief open season, to determine an appropriate bid. This could limit the number and effectiveness of shippers interested in bidding in the open season.

One way to address these concerns is to require at least a 90-day notice period prior to the start of the open season and further require disclosure of all critical information needed to make an informed and competitive bid.

Another major concern is the potential for the project sponsors to "hold back"capacity from the open season process. Recently, in a number of FERC-regulated natural gas pipelines, sponsors have held back up to 50 percent of the pipeline's capacity. This would put potential non-owner producer/shippers on the Alaska gas pipeline at an obvious disadvantage. Given that this is the only gas pipeline likely to be constructed from the Alaskan North Slope to the Lower 48 states, none of its capacity should be withheld.

Tariff Issues

One of the major concerns of potential non-owner producer/shippers on the Alaska gas pipeline is the amortization period used in the tariff calculation for the recovery and return on capital investments. A short amortization period would result in an excessively high tariff, which would reduce the netback gas price received by gas producers. Given the remote location and seasonal limitations on drilling in Northern Alaskan, new natural gas developments will be quite

expensive. If the tariff is too high, the netback price after transportation costs are deducted could render natural gas development uneconomic.

This is not an issue for major North Slope producers who also would be major equity owners in the pipeline, but it is a major concern to non-owner producers as they evaluate the economics of new, high-cost gas exploration and development projects.

Another major issue is to ensure that the pipeline tariff is "unbundled" as to ancillary services. Unbundling has been FERC policy for the past decade. However, there is concern that the producer/sponsors of the Alaska gas pipeline intend to include in the tariff the costs of a gas conditioning plant that would extract CO_2 from Prudhoe Bay gas prior to injection into the pipeline.

CO_2 is a corrosive gas that must be reduced to minimal levels prior to delivery into the pipeline. Cost estimates for the CO_2 plant have been estimated at $1 billion or more – which could amount to 50 cents per MMBtu or more.

By including ancillary service costs in the overall pipeline tariff, the producer/sponsors would effectively require producers of other smaller, less profitable gas fields to subsidize the largest untapped natural gas field in North America. It should be noted that the gas found in many of the new Northern Alaska gas fields is expected to be of pipeline quality and would not require CO_2 conditioning.

If gas from some new field discoveries did require conditioning – and these discoveries were located in areas "downstream" of the Prudhoe Bay CO_2 conditioning plant, such as the Brooks Range – operators would have to install their own CO_2 conditioning plants, while subsidizing the Prudhoe Bay CO_2 conditioning plant.

There are concerns that a tariff process could be structured to disadvantage non-owner shippers in a number of other ways, too. If the pipeline sponsors set the minimum Btu content at higher than normal levels, for example, this could deny capacity to producers of leaner natural gas fields – fields whose gas does not contain a high concentration of associated natural gas liquids (NGLs) such as ethane, propane and butanes.

Another concern is the potential for the sponsors to require shippers to forfeit their rights to valuable NGLs entrained in their gas streams. This is purported to be the case on the recently completed Alliance Pipeline. This would allow pipeline sponsors to reap a windfall by keeping

NGLs from shippers' gas. NGLs typically hold a higher value when extracted and sold separately than they do when sold as part of a high-Btu gas stream.

Yet another concern is that sponsors may choose to compute tariff rates on a volumetric (Mcf) basis rather than on a heating value (MMBtu) basis. Natural gas is now bought and sold on an MMBtu basis; computing the tariff on an Mcf basis would result in leaner gas subsidizing richer gas streams.

One final concern is to ensure that the pipeline has multiple connection points and multiple delivery options. New natural gas fields discovered along the pipeline route should be afforded interconnection to the pipeline if capacity exists. Also, if new markets develop along the pipeline route, new delivery points should be set up to serve these markets.

Accordingly, the tariffs charged for shorter rides on the pipeline should be computed on an actual mileage basis and should not be charged at full fare.

Pipeline Expansions

FERC does not have the authority to order pipeline expansion to accommodate development of new natural gas reserves in Alaska. To discourage new competition in Alaska, pipeline producer/sponsors may find it to their advantage to refuse to expand or to delay expansions.

Because of this, any bill enacted to allow expedited construction of an Alaska gas pipeline should give FERC the authority to require expansion of the pipeline when credible shippers are willing to enter into long-term transportation arrangements to support and justify an expansion.

For example, a third-party exploration company might make a major gas discovery, petition the pipeline for an expansion and indicate a willingness to commit to long-term transportation contracts to justify the expansion costs. If this were to occur a few years before the owners of the Prudhoe Bay Unit were ready to increase gas production from their field, they may delay the requested expansion so that they could be better positioned to secure pipeline capacity for themselves at expansion.

Owners of Prudhoe Bay have an incentive to reinject a significant portion of the produced gas until some time after 2010 in order to maximize oil production. However, once gas injection no longer has an appreciable impact on the recovery of oil, the owners will likely seek to greatly increase natural gas production.

This access to and timing of pipeline expansions is a critical issue, inasmuch as there are physical limitations to how much the pipeline can be expanded. Current thinking is that the maximum the pipeline can be expanded is from 4 Bcf per day to 6 Bcf per day.

Analysis of proposed
Alaska Natural Gas Pipeline Act of 2001
By Mike Macy

279-8247

Summary

No need to expedite; companies have been stalling for years and are still
Will create federal Energy Czar
Severely limits public's right to challenge
Emasculates regulatory agencies
Sets terrible precedent in bypassing NEPA
Allows companies to decide when and how our gas goes to market (if at all)
(instead of legislature)
(In violation of Alaska's constitution)
Murkowski should be embarrassed that the companies even think he might be willing to introduce it.
It allows companies to circumvent existing permit holders
It should be called the Alaska Gas Stranding and/or Giveaway Act of 2001s
If this passes, Alaska becomes another Louisiana. It gives the companies a stranglehold on the state for the next century.

Line by line comments

Title: There isn't going to be more than one project. There isn't enough gas or capital.

Sec.2. (2) Proven North Slope reserves have been reduced to 29 TCF as a result in the course of providing fuel and Miscible Injectant for North Slope operations.

Sec. 2. (6) This is also erroneous and misleading. Parties seeking to develop the Alaska to Alberta section on ANGTS secured every regulatory approval they sought. They never sought financing because before they got to that point they determined that their project was uneconomic. There is no evidence that the present regulatory scheme would hinder the expeditious review, permiting, and finance of a project.

Sec. 2. (7) Exceedingly vague. The truth is that ANGTA requires a 2.4 BCF/day project that fails to meet economies of scale. The 4.0 bcf/day minimum size project required to achieve economies of scale will according to Cambridge Energy Research Associates depress the minimum price needed to make the Alcan project economic.

Sec. 2. (8) This ignores the LNG option as does the entire legislation.

Sec. 2 (9) Economic viability has much more to do with demand, supply, and volume than with expeditious permitting and EISs.

Sec. 3.

(a) Competitive market forces aren't keeping Alaska's gas out of Asia or the West Coast. Warehousing is. Competitive supply forces may keep Alaska's gas out of the lower 48 for years.

(b) Expedited review and approval is just a euphemism for giving BP, Exxon, and Phillips a way to bypass existing permit holders and dictate how, when, and even if our gas will go to market.

(c) This is right out of George Orwell's 1984 "full consideration consistent with the need to expedite" is a complete oxymoron. This gives the Office of The Federal Pipeline Director unlimited discretion.

(d) This strips citizens, interested parties, of a host of legal protections and recourses.

Sec. 4.

(6) This part of the definitions section specifically excludes LNG or the LNG approach to moving gas to the West Coast. If moving gas to the lower '48 is so important, why would we preclude the only option that is free of interference by the Canadians?

Sec. 5. (a)(14) Anybody can be a shipper. Antitrust considerations argue for precluding any major North Slope gas leaseholder from owning any part of the pipeline.

(15) "Alaska Facilities Gas Project" definition again precludes the LNG option.

Sec. 5. (b) (3) By requiring the Commission to issue a certificate of public convenience and necessity to <u>any</u> person, the Act greases the wheel for allowing BP, Exxon, and Phillips to go around the exisiting permit holders, YPC and Foothills rendering hundreds of million of dollars of investment and environmental review that was not rushed worthless.

(b) (4) The rules by which the commission may issues a certificate of public convenience are supposed to be set forth in subsection (e) which is missing.

Sec. 6. (a) (1) Replaces NEPA with a non-NEPA process. This is a terrible precedent for which no coherent justification has been presented.

(a) (2) Hamstrings federal regulatory agencies.

(b) and (c) Creates a new lead agencies for federal review, one with an expedite as opposed to an environmental or public interest mandate.

(c) Requires expedited review whether it is needed or justifiable or not.

(e) Seems to arbitrarily limit the scope of the environmental review so that it doesn't have to consider other alternatives such as existing, permitted projects.

Sect. 7. (a) Creates a new Pipeline Czar in the President's office. How responsive to the environment or the public interest do you think such a person appointed by the current Administration would be?

(b) Empowers the Czar to bring the full weight of the White House to bear on any federal agency that tries to assert its authority to protect the environment or the public interest. Furthermore, allows the regulatory agencies to duck their responsibilities by delegating them to the Federal Pipeline Director. .

(c) Gives the Director/Czar authority to drive/expedite the agency review process.

Sec. 8. (a) Requires every action by any federal officer or agency to be expedited.

(c) Gives the Czar unlimited discretion in rejecting stipulations which might otherwise make the project safer or more environmentally sound.

(d) Strips agencies of their ability to require stipulations, unless the Czar agrees.

Sec. 9. Limits challenge of the Act to the first 60 days after passage. Violates citizens rights to due process and access to the courts as if there was some sort of national emergency.

(c) Forces all challenges to the Court of Appeals for the District of Columbia. This puts an onerous burden on Alaska citizens and basically violates our civil rights.

Sec. 10. Confers eternal life on Act. No matter how many parts the courts throw out, the Act keeps on ticking.

Foothills Pipe Lines Alaska, Inc.

September 11, 2001

Senator John Torgerson
Alaska State Legislature
35477 Kenai Spur Highway, Suite 101 B
Soldotna, Alaska 99669

Dear Senator Torgerson:

I am in receipt of your letter dated September 5, 2001, raising several questions relating to the Producer sponsored legislation and what, if any, federal legislation is either necessary or desirable to expedite the construction and operation of the Alaska Natural Gas Transportation System. In your letter, you also request that I testify on behalf of the Alaska Northwest Natural Gas Transportation Company (ANNGTC) as the holder of the certificates to build and operate the Alaskan portion of the Alaska Natural Gas Transportation System (ANGTS). These certificates were, as you know, issued pursuant to the substantive provisions of the Natural Gas Act (NGA) and the procedural regime established by the Alaska Natural Gas Transportation Act (ANGTA) of 1976.

First, I understand that the Joint Committee will be meeting in Anchorage on September 19, 2001. I confirm that I will be available to testify before the committee on that date.

Second, with respect to an analysis of the Producers' proposed legislation, I provided one to the Committee by letter dated September 5, 2001. I trust you have received this analysis.

With respect to your question regarding possible alternative federal legislation as a legal matter, the ANNGTC does not believe any federal legislation is necessary in order to construct and operate a modern Alaska Natural Gas Transportation System. The ANNGTC has provided representatives of the Committee with our detailed analysis of the entire "ANGTA Regime" including ANGTA, the President's Decision, the President's Report in support of his decision, the Agreement on Principles between Canada and the United States, the Northern Pipeline Act in Canada as well as the certificates granted by Parliament to Foothills to own, construct and operate the Canadian portion of the ANGTS. We fundamentally believe that this regime taken as a whole is sufficiently flexible and provides the legal framework to bring the ANGTS to modern standards of pipeline design, construction and operation. In addition, we believe the regime

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provides the statutory and regulatory framework to modernize the tariff to reflect current market conditions. Therefore, the ANNGTC and Foothills do not believe that any federal legislation is necessary to permit construction and operation of a modern ANGTS.

You also asked whether any federal legislation would be "useful." If federal legislation could be enacted to confirm Congressional intent with respect to questions which have arisen regarding the scope and flexibility of the ANGTA regime to accommodate the modernization of the design and tariff of the ANGTS, then such legislation may be useful to reduce uncertainty and to focus stakeholders on building the ANGTS.

The ANNGTC and Foothills are aware that numerous stakeholders are considering proposing legislation. Foothills welcomes the efforts to assist in achieving ANNGTC's shared goal to build and operate the ANGTS. We have offered to assist those drafting legislation to consider objectives and language so "no harm will be done" to the ANGTS Regime. We continue to be ready to work with stakeholders sharing a common goal to develop a consensus alternative to the Producer sponsored legislation. A consensus legislative approach that confirms the ANGTS decision and framework and clarifies questions which have arisen as stakeholders focus on modernizing the design, construction, operation and tariff for a thoroughly modern ANGTS could be useful.

Sincerely,

John Ellwood

JRE:js

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VanNess Feldman
ATTORNEYS AT LAW

Facsimile

TO

Senator John Torgerson — 9/4/01
NAME — DATE

Alaska Senate — 2:50
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VanNess
Feldman
ATTORNEYS AT LAW

August 2, 2001

Honorable Frank H. Murkowski
United States Senate
Washington, D.C. 20510-0202

Dear Senator Murkowski:

This letter responds to your request for the views of Foothills Pipe Lines, Ltd. on the draft Alaska Natural Gas Pipeline Act (ANGPA) recently submitted by the Alaska North Slope natural gas producers.

Foothills has analyzed ANGPA and has reached the conclusion that legislation of this type is not needed to provide a legal and regulatory framework to expedite the construction and initial operation of an Alaska natural gas pipeline. That legal and regulatory framework already exists in the Alaska Natural Gas Transportation Act (ANGTA). The producers' proposed legislation contradicts the very purposes that ANGTA has achieved. If enacted, it would create a confusing and chaotic parallel procedure for authorization of an Alaska natural gas pipeline.

Foothills believes that enactment of the ANGPA is justified only if the Congress desires to accomplish the following objectives:

1. To revisit the previous careful and deliberative selection of the Alaska Highway route as the most economically and environmentally sound route and allow consideration of other route options, including the "over the top" route.
2. To authorize the filing of new producer sanctioned applications that could exclude any independent pipeline company participation in the ownership and governance of the Alaska pipeline.

Evidence supporting these conclusions can be found in the proposed legislation itself in that each major provision designed to expedite construction and operation of the pipeline is copied almost directly from existing law – ANGTA.

As you are aware, ANGTA engaged the regulatory expertise of the federal agencies, the international expertise and jurisdiction of the President, and the public decision making process of the Congress before selecting a route and project to deliver Alaska natural gas to lower 48 markets. In contrast, ANGPA would appear to place responsibility for those critical judgments in the hands of the North Slope gas producers. This raises profound public policy issues, not only for the Congress, but also for natural gas consumers and, most importantly, for Alaskans.

Finally, the proposed legislation is not needed because the parties already authorized to construct and operate the Alaska Natural Gas Transportation System, Foothills, TransCanada and Westcoast, are ready, willing and able to build that pipeline as soon as the producers decide to market their gas. In this regard, Foothills continues to explore avenues to establish a collaborative dialogue with the ANS producer group. We would greatly appreciate any efforts on your part to encourage the producers to join in such a dialogue.

We look forward to continuing to work with you on this very important matter. Please call me if you have any questions.

Sincerely,

Tom

Tom Roberts
On behalf of Foothills Pipe Lines, Ltd.

ANNGTC Partners Listing
(Successor or parent company shown in brackets)

Withdrawn
American Natural Alaskan Company (El Paso)
Calaska Energy Company (PG&E)
Columbia Atlantic Trading Company (Williams)
Northern Arctic Gas Company (Enron)
Northwest Alaskan Pipeline Company (Williams)
Pacific Interstate Transmission Company (Sempra)
Pan Alaskan Gas Company (Duke)
Tetco Four, Inc. (Duke)
Texas Gas Alaska Corporation (Williams)

Active
TransCanada Pipelines USA (TransCanada)
United Alaska Fuels (Foothills)

Share Control
Under the terms of the Partnership Agreement all active partners contributed equally to the capital requirements of the Partnership.

ENERGY POLICY -- (Senate - September 06, 2001)

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Mr. BINGAMAN. Mr. President, I will take this opportunity to speak for a few minutes on the work that is currently underway in the Energy and Natural Resources Committee on which the Presiding Officer serves with great distinction. We are making an effort in that committee to develop a comprehensive and balanced energy policy. I want to inform my colleagues about the likely steps we will be following in the near future.

As I see it, Congress has a real opportunity this fall to set an energy policy that will sustain our economic prosperity as we move into this new 21st century. The Senate has a key role to play in seeing this opportunity does not slip through our grasp.

A great deal has changed since 1992, which is the last time Congress enacted major energy legislation. We have seen energy markets become more competitive and more dynamic. But we have also seen some significant bumps along the way.

First of all, consumers are more vulnerable to the vagaries of the energy markets than they ever were before. I think the evidence we have of what happened in California with electricity prices is one example.

Second, gasoline supplies are increasingly subject to local crises and price spikes due to the proliferation of inflexible local fuel specifications.

Third, we rely more heavily each year on natural gas--natural gas to heat our homes and to produce electricity. But our system for producing and transporting that natural gas is showing signs that it is reaching its limits.

Fourth, the need to address the fundamental connection between energy and global warming is something that is becoming a major concern of many of us, and I think rightly so.

So I am pleased most of my colleagues in the Senate recognize these challenges. I believe there is a bipartisan consensus in favor of a sensible energy policy that will smooth out the bumps in the market by increasing energy efficiency, by boosting our energy supplies, by modernizing our energy infrastructure.

Technology and policy innovations will be key to achieving this balanced outcome so Americans can have reliable and affordable energy choices that are sustainable over the long term. Our energy problems cannot be effectively addressed by packaging up a collection of tired old wish lists and passing that through the Senate floor in a day or two. Energy consumers and producers, and several committees here in the Senate, will need to focus on new energy approaches if we are to protect our national economic prosperity and do so through smarter ways to produce and use energy.

For this reason, as the Senate takes up and considers energy legislation this fall, we will be talking about the need for proactive policies, about the need for technology-driven approaches to our energy problems. We have made a good start already in the Committee on Energy and Natural Resources. We began our markup in July, before the August recess--a markup of comprehensive energy legislation.

The first part of the bill that we have substantially completed at this point is a comprehensive revitalization of the

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national capabilities for energy research and development. Putting research and development first reflects a broad consensus that new science and new technology are at the core of any solution to our national energy challenges. Despite the importance of energy R&D, our recent commitment to it leaves a great deal to be desired. The level of effort we are making

today in Federal energy technology research and development is equivalent in constant dollars to what we were making in 1966. Yet our economy is three times larger today than it was in 1966. It is very hard to see how we can build a 21st century energy system on a 1960s level of effort in the research and development budgets.

The committee will begin its deliberations beginning this next week and its effort to mark up a bill this next week. Major topic areas before the committee as we move forward in this markup will include policy proposals to improve energy efficiency, to improve our ability to produce energy from a great diversity of sources, and to tackle the tough issues related to electricity restructuring.

Today I am releasing a detailed description of the proposed chairman's mark in these various areas. I am also releasing the text of the major portions of the bill we will be working on in committee--the next major portion of the bill. This part of the bill will deal with electricity, and it will provide a framework to integrate new technologies into electricity markets to provide high-quality, efficient electricity generation in every community and to give consumers new ways to manage and control energy use and energy costs.

I would like to take an opportunity to describe some of the key proposals in the mark that we will be considering in a little more detail. With respect to energy efficiency, the chairman's mark that we will be considering for the energy policy bill will contain provisions that will improve energy efficiency in household appliances--also provisions that will improve energy efficiency in Federal and other facilities and industry itself.

Let me state my belief, though, that increasing vehicle fuel efficiency is one of the highest legislative priorities that the Senate should have in energy legislation. In addition to our growing dependence on foreign imported oil, we have reached the limits of our current infrastructure to refine and distribute fuels. A policy of simply continuing to increase the demand for gasoline is not sustainable. Fortunately, advanced technology in a variety of areas to improve automotive fuel efficiency offers a better answer, and we need to move in that direction.

The National Academy of Sciences has given us some very useful ways of thinking how to reformulate the CAFE program. Clearly, consumers want the option to choose the type of vehicle that suits their needs and preferences. They also want to be able to count on reliable and affordable fuel supplies.

While CAFE standards are not in the Energy Committee's jurisdiction, a number of other mechanisms to encourage greater fuel efficiency in cars and trucks are in our jurisdiction. The mark will contain purchase requirements for Federal fleets that will provide greater incentive to automobile and truck manufacturers to produce more highly efficient vehicles.

A topic closely allied to vehicle fuel efficiency is the question of the fuels that we will need in the future to power cars and trucks. Here, the Congress has a clear duty to address the growing multiplicity of fuel specifications around the country. Part of the solution to this problem will be provided by a bill in the Committee on Environment and Public Works, sponsored by Senators SMITH and REID. I hope that these provisions find their way into our overall energy bill in the Senate.

The Chairman's mark will include a number of energy efficiency provisions relating to appliances. Perhaps the most visible proposal in this regard will be one that enacts a 13 Seasonal Energy Efficiency Rating for central air-conditioning units. Such a standard was finalized earlier this year, but since then the Bush Administration has attempted to withdraw it and substitute a lesser standard. The Committee on Energy and Natural Resources held hearings on this topic and the record before the committee has persuaded me that the administration based its decision on economic information that was outdated and inaccurate.

A 13 SEER rating for central air-conditioning units can do a lot to help avoid summer blackouts and brownouts when high temperatures send electricity demand soaring. During the intense heat wave we had in early August, which was felt nationwide, peak demand from air-conditioning did, in fact, lead to problems in electricity availability in some parts of the country, while others were uncomfortably close to the margin. We need to build more efficiency into this part of our system over the long term, and a higher standard for these large air-conditioning units will help.

The Chairman's mark will also require the Federal government to purchase Energy Star or other efficient products designated by the Federal Energy Management Program. This is a requirement that, again, makes eminent sense. Taxpayers save money, and the cost of energy-efficient appliances to consumers comes down, when the Federal government takes a leadership role in purchasing highly energy efficient computers, office machines, and other appliances.

The mark also authorizes a grant program to help build energy-efficient schools. School districts can ill afford to waste taxpayer funds on excessive energy bills because of the inefficiency of school buildings.

With respect to new energy sources, it is important that the Senate look to policies that will truly improve our supplies of domestic energy security, including measures to improve our supply of natural gas and to diversify our energy mix to include a greater reliance on domestic renewable resources. These are the types of provisions that I will include in the Chairman's mark.

I will not be including in the mark any provisions relating to drilling for oil in the Arctic National Wildlife Refuge. The debate over oil drilling in the Arctic National Wildlife Refuge--a long-standing bone of contention in energy policy--is in many ways a distraction from more important opportunities to bolster our domestic energy security. Oil produced from the arctic refuge is not likely to influence the world price of oil, or the prices that U.S. consumers pay for gasoline. I plan to focus attention in the Energy Committee mark-up on a number of issues that will have a greater impact on our domestic production of oil and gas and a larger near-term impact than drilling in the Arctic.

The first such issue is another Arctic resource that could be brought to U.S. markets--natural gas. The exploration for oil in the Prudhoe Bay region of Alaska has resulted in the discovery of abundant supplies of natural gas, but there is now no way to bring that gas to markets in the lower 48 States that could benefit from it. The projection of growing demand for natural gas has re-awakened interest in building a pipeline from Prudhoe Bay to Alberta, Canada, where it would join with existing gas pipelines that serve the United States. That pipeline would be an enormous construction project on the part of the private sector, requiring perhaps 2,000 miles of steel pipe and costing $20 billion. A lot of spurious job numbers have been floated about drilling in the Arctic Refuge. The gas pipeline would be the real thing as far as job creation is concerned.

If we do not act while there is substantial private-sector interest in building the Arctic gas pipeline, we will lose an important opportunity to bolster our national energy security in natural gas. If we do not bring the Alaska gas to market, then our growing demand for gas will be met by large-scale import of liquefied natural gas. At $3 or less per million BTU, imported LNG will be cheaper than Alaska gas. But it would be foolhardy to look at the issue solely through the prism of short-term economics. We are already more than 50 percent dependent on foreign oil. If we do nothing about the Arctic gas, we could wind up being similarly dependent on foreign natural gas, from many of the same OPEC countries from which we import oil. That is an economic and national security issue.

We face a clear moment of decision. The Chairman's mark that I will bring before the Committee will contain authorizing provisions to streamline the

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regulatory approval process to move forward with the pipeline. We may find a mechanism to ensure that the domestic option for a pipeline route is chosen. I hope to be able to work with my colleague from Alaska during the mark-up to help make that happen.

The second key initiative for domestic production is to undertake a top-to-bottom review of both federal and State royalty and tax policy on domestic oil and gas production. Our current policies were put in place when the U.S. had abundant and easily accessible reserves. We have fewer such reserves now, and while technology for finding oil has continued to improve, we should consider whether the financial structure we have in place should change to one that enhances the economics of exploring for oil and gas in more challenging geological formations. It should also take into account the boom-and-bust nature of the industry, and provide incentives to maintain domestic production when prices are low.

The third proposal is to provide adequate funding for the federal programs that actually make new leases for oil and gas available to domestic producers. For all the rhetoric from the administration about the need to boost production, it has not asked for enough money in order to bring this about.

The result is likely to be further delays and frustration on the part of U.S. oil and gas producers. In the mark that I will present to the committee, we will authorize a higher level of funding for the necessary personnel to make the decisions and to process applications for domestic production.

The area of electricity, as I mentioned earlier in these remarks, is the next major topic that we will take up in the markup. We do need to provide for reliable and diverse electric power generation and distribution sources in the country. Electricity is a central part of modern life. Yet our electric system largely operates on a design that is nearly a century old. There are many problems in our electricity markets that need to be addressed. The problems faced by California and the West earlier this year should be a wakeup call to all of us.

What the electricity crisis in California showed is that the institutions that developed in the last century have not evolved enough to ensure reliable and affordable supplies of electricity. We face a crucial turning point. During the next few years, billions of dollars of investment will be planned and committed to electric generation and transmission. Those investments will have a 30- to 50-year lifespan. Will we put in place a structure to maximize the chances that investments will go to new technologies that will give consumers real choices over their energy use or will Congress, by its inaction, perpetuate obsolete frameworks for managing electricity markets, with the result that we wind up with little improvement in the status quo?

I believe that we in Congress and the President have a great opportunity to be visionary about the future of electricity. A transmission grid that is open to a wide variety of generation options, including distributed generation, will ensure the power quality and efficiency that our 21st century society will need in order to sustain our economic prosperity.

That opportunity creates a great duty on the part of Congress and the President to focus on electricity as a major part of comprehensive energy legislation. Our task must be to build a regulatory structure that has adequate authority to resolve market defects, without interfering unduly in those markets.

I believe we need to move forward now with a legislative solution to these problems. To leave electricity legislation for another day would be to perpetuate an obsolete system that will not provide the reliability, quality, affordability, and choice that consumers will want and need.

The changes that I believe are needed, and that we are going to be trying to address in the chairman's mark, include the following:

First, we will try to clarify who has jurisdiction over regulating electricity transmission in interstate commerce. That is a key part of what the legislation will do.

That role is assigned to the Federal energy Regulatory Commission, or FERC. FERC will be given authority to ensure that all electric transmitting organizations in interstate commerce play by a consistent set of fair rules.

Second, the chairman's mark will give FERC the responsibility for taking the current voluntary system for promoting reliability in electric transmission and making adherence to reliability rules mandatory.

Third, the chairman's mark will give the FERC the tools to ensure that competitive markets work well to provide customers with affordable electricity.

Fourth, the chairman's mark will address the tough issue of siting new transmission facilities. This is something the President has indicated his support for. A national transmission grid is a necessity, but cannot occur without a new approach to transmission planning, expansion, and siting. Federal eminent domain, by itself, is not likely to lead to an effective approach to meeting this need. What is needed is to use federal eminent domain as a backstop to a more cooperative, regionally based approach to transmission and siting issues. Thus, the chairman's mark will rely on regional transmission organizations to do the bulk of transmission planning, expansion and siting. Only if those regional entities are stymied will a federal eminent domain authority be invoked, and that authority will be used only to implement the decisions taken regionally.

The chairman's mark will include a repeal of the 1935 Public Utility Holding Company Act, or PUHCA, but the protections in that act will be replaced by giving FERC jurisdiction over mergers of holding companies that own utilities and over acquisitions of generation assets.

Finally, the chairman's mark will ensure that there is transparent information on market transactions.

As part of a balanced and comprehensive legislative solution, the chairman's mark also includes numerous benefits and protections for consumers, so that we don't repeat the mistakes of telecommunications deregulation. These include an emphasis on ensuring future access by rural, remote, and Indian communities to electricity; protection of consumers from unfair trade practices; and a Public Benefits Fund to ensure that there is a way to fund electricity programs in the public interest.

The chairman's mark also includes a series of provisions to ensure that we have a greater role in our electricity generating system of the future for renewables and distributed generation, while maintaining the contribution made by existing sources

of baseload generation, such as hydropower and nuclear. Among the important tools for making sure we have diversity in our sources of electricity is a renewable portfolio standard, uniform interconnection standards to the electric grid, greater flexibility and predictability to the process of relicensing hydroelectric dams, and a reauthorization of parts of the Price-Anderson Act.

Finally, a common thread among may of the provisions that I have mentioned in this chamber today and that we will be considering in the bill is perhaps the most important public policy challenges of the 21st century, and that is climate change. Climate change policy and energy policy are inseparably linked, because energy production and the use of energy are leading sources of greenhouse gases that affect the atmosphere. The Senate must ensure that the energy legislation it passes makes a meaningful, positive contribution to dealing with this issue. Many of the provisions that I have already discussed--energy efficiency, the focus on more renewables--make a contribution to this goal. The mark that we will be considering in committee will contain some additional provisions to promote better information and policy on greenhouse gas emissions.

Energy policy is a difficult and complex topic. Getting to a solution that gives America a vibrant energy infrastructure and the right policies for the 21st century will require careful work on complicated issues. Our Nation's future economic prosperity, and the jobs of millions of Americans, are at stake. I hope that the approach taken in the Senate combines a thoughtful analysis of our current energy challenges with a willingness to take some bold policy steps to address those challenges. That certainly is the spirit in which I will be making proposals before the committee.

I look forward to working with all my colleagues in the Senate to produce constructive legislation for the future of our country.

Mr. President, I yield the floor.

Alaska Gas Producers Pipeline Team
601 W. 5th Ave. Suite 500
Anchorage, Alaska 99501
907-770-8000

September 12, 2001

Senator John Torgerson
35477 Kenai Spur Highway, Suite 101B
Soldotna, Alaska 99669

Dear Senator Torgerson,

In response to your September 5, 2001 letter, we would like to confirm the participation of the Alaska Gas Producers Pipeline Team in your upcoming September 19, 2001 hearing. Additionally, we would like to take this opportunity to correct some apparent misconceptions in the background portion of your letter, and respond to the questions you outlined at the end of the letter.

In the third paragraph of your letter, describing the four significant concepts of the proposed legislation, you note in the second item that "it requires a thorough environmental review and a single environmental impact statement (EIS) for two separate segments..." It was perhaps unclear, but our intent in the proposed legislation is to have two distinct EISs for the two segments. We believe that the timing of the commercial work for the Alberta to market segment would be such that it would be advantageous to the overall project timing to separate the two segments for EIS purposes. We do not wish to create a situation where the time consuming commercial discussions which will accompany the Alberta to market segment hold up or delay the completion of the EIS for the North Slope to Alberta segment.

Much of the commentary you cite in the background of the letter seems to focus on a perception of the producers "control" of the project. This is perhaps most clearly articulated in the fourth paragraph of the letter which concludes that only the producers can receive a certificate under this proposed legislation. This is not true.

The proposed legislation cites three requirements for certification, the relevant one of which states "such person has reached agreement with a Shipper of Alaska Natural Gas for the transportation of natural gas through an Alaska Facilities Gas Project..."

bp ExxonMobil Phillips 66

That language, if you read the definitions in section 5 (a) (14) of the proposed legislation, refers to anyone who is willing to sign a shipping commitment with the potential certificate holder. Entities who could be in a position to do that, over and above the three producers currently studying the project, would include other current or potential gas producers, the State of Alaska (wishing to market its royalty share), or gas marketing companies, such as Duke, Williams or Enron, to name a few. The requirement for certification is to have a shipping commitment, not to have ownership of gas reserves, and we believe this needs to be clear.

With respect to your questions, let us begin by confirming that, from our perspective, enabling federal regulatory legislation is essential to our moving forward on our joint producer study. We proposed this legislation because we believe it is necessary to reduce the current regulatory uncertainty surrounding this project.

That being said, we recognize that there may be legitimate issues which may come forward as people review and consider the proposed legislation. As we have repeatedly stated, we stand prepared to work constructively on any proposed changes which help to address legitimate concerns. To facilitate the upcoming discussions, we have attached the sectional analysis of our proposed legislation.

Thank you for your invitation to the upcoming hearing. We will be prepared to discuss the proposed legislation at that time and respond to any questions you or your committee may have.

Sincerely,

_____
Ken Konrad
BP Exploration (Alaska) Inc.

_____
Robbie Schilhab
ExxonMobil Production Company, a division of Exxon Mobil Corporation

_____
Joe Marushack
Phillips Alaska, Inc.

Att

MJH:mb

Sectional Analysis

Section 1 — Short Title

- "Alaska Gas Pipeline Act of 2001"

Section 2 — Congressional Findings

- This section sets forth findings that support the need for the legislation.
- The findings note the existence of substantial natural gas resources on the North Slope, the importance of those resources to the nation's long-term energy needs, the 1976 enactment of special legislation to facilitate the approval and construction of a transportation system to move Alaska gas to the Lower 48, the failure of that legislative effort, the outdated features of the previously approved system, and the current renewed interest in constructing a transportation system to move the gas to the Lower 48.
- The findings explain that it is in the national interest to encourage the development of one or more environmentally sound transportation systems through sensible expedited regulatory procedures and to rely to the extent possible on competitive market forces to determine the future development of North Slope gas.

Section 3 — Congressional Statement of Purpose

- This section explains that the legislation seeks to expedite the approval, construction, and operation of one or more transportation systems for delivering North Slope gas to the Lower 48 by relying on market forces to determine which projects are economically viable; expediting the certification and permitting processes; ensuring compliance with environmental laws; establishing a Federal Pipeline Director to coordinate and move the process forward; and expediting, and narrowing the scope of, judicial review.

Section 4 — Definitions

- This section defines various terms used throughout the Act.
- Definition of "Alaska Natural Gas" is identical to that used in ANGTA.
- Uses "Alaska Facilities Gas Project" and "Lower 48 Facilities Gas Project" to differentiate between A-to-B and B-to-C segments, respectively.

Section 5 — Expedited Approval Process

- Adds a new Section 7(c)(3) to the Natural Gas Act requiring FERC to grant any and all applications to build the Alaskan part of A-to-B facilities if three criteria are satisfied:

  (1) The applicant must have reached an agreement with a "Shipper" of Alaska Natural Gas for the transportation of that gas with the intent that all or a portion of the gas ultimately will be delivered to the Lower 48 States.

  ◊ A "Shipper" essentially is any person that has entered into an agreement with the applicant for the transportation of Alaska Natural Gas; anyone who, through contract or otherwise, controls Alaska Natural Gas may be a Shipper.

  ◊ This provision reflects a market-based approach, not unlike that reflected in Section 311 of the Natural Gas Policy Act

  (2) FERC must be satisfied that "rates and charges for, and terms and conditions of" such transportation services can be established in accordance FERC's usual procedure.

  (3) FERC must be satisfied that terms and conditions for compliance with all applicable environmental laws can be established in accordance with FERC's usual procedure.

◊ The latter two requirements assure that certain key aspects of traditional pipeline regulation under Section 7 of the Natural Gas Act, including protection of ratepayers and protection of the environment, will be followed with respect to any Alaska Gas Facilities Project.

- To provide for expedition, FERC is directed to act on any Alaska Gas Facilities application within 18 months.

- Adds a new Section 7(c)(4) to the NGA under which the Commission may issue a certificate authorizing construction of facilities to transport Alaska Natural Gas from the Canadian border to markets in the Lower 48 States. Such applications will be considered pursuant to the Commission's normal Section 7 procedures.

Section 6 — Environmental Reviews

- Requires a *single* EIS for each proposed "Alaska Gas Project." This means that:
  - ✓ EISs for A-to-B projects will be prepared separately from EISs for B-to-C projects
  - ✓ *Each* proposed project will be studied in a separate EIS
  - ✓ Agencies must work together to prepare a single EIS for each project

- Requires each EIS to be prepared pursuant to the lead agency's regulations and procedures.

- Designates the lead agency for each EIS as follows:
  - ✓ FERC will be the lead agency for all EISs for A-to-B projects
  - ✓ FERC will be the lead agency for all EISs for B-to-C projects.

- Sets deadlines for completing the EISs:
  - ✓ Draft EIS within 12 months after filing of complete FERC certificate application
  - ✓ Final EIS within 6 months after DEIS (i.e., 18 months total for EIS preparation)
  - ✓ Deadlines may be extended by FERC for good cause

- Requires consistency between the *scope* of the EIS and the *scope* of FERC certificate application. This means:
  - ✓ EIS focuses on project within FERC jurisdiction (Canadian portions are reviewed by Canadian agencies, not by FERC; this is consistent with current FERC practice)

Section 7 — Federal Pipeline Director

- Creates the Office of the Federal Pipeline Director in the Executive Office of the President. The Director would be appointed by the President and confirmed by the Senate.

- Overall responsibilities of the Director include "coordinating the expeditious discharge" of all federal agencies' activities on Alaska gas projects (A-to-B and B-to-C). Gives agencies *discretion* to delegate decision-making authority to the Director, but does not require them to do so. (Similar to ANGTA provision for non-enforcement regulatory responsibilities).

- Specifically charges the Director with responsibilities for "coordinating the expeditious completion" of all environmental and other studies for Alaska gas projects. This role includes coordination with federal, state, local, and tribal agencies, as well as coordination with Canadian agencies (via the State Department).

- Requires the Director to report semi-annually to Congress on the status of all pending applications for Alaska gas projects.

- Authorizes the appropriation of funds for the Director's Office.

Section 8 — Agency Reviews and Decisions

- Directs federal agencies to expedite their handling of all Alaska gas project actions.
- Requires the federal agencies involved in Alaska gas projects to cooperate and coordinate with one another to expedite the decision-making process – through MOUs, joint documents, joint meetings, etc.
- Prevents federal agencies from including discretionary terms in permits if the Federal Pipeline Director finds that such terms would "prevent or impair in any significant respect the expeditious construction and initial operation of an economically viable and environmentally sound system."

Section 9 — Judicial Review

- Time limits: challenges to this Act's validity must be brought within 60 days of its enactment; challenges to actions by federal agencies or officers under the Act must be brought within 60 days of such action.
- Jurisdictional Limits: judicial review is limited to claims of constitutional violation or agency action in excess of statutory authority. Precludes claims that federal agency actions are "arbitrary and capricious."
- Exclusive Jurisdiction of Special Court: challenges to this Act or actions taken thereunder must be brought directly in the U.S. Court of Appeals for the D.C. Circuit.
- Expedited Procedures: does not impose specific deadline but directs the D.C. Circuit to provide expedited consideration.
- Similar limitations on judicial review are contained in ANGTA.

Section 10 — Separability

- Provides that, if any provision of this Act, or application thereof, is held invalid, the remainder of the Act is unaffected.

YUKON PACIFIC CORPORATION
TRANS-ALASKA GAS SYSTEM

JEFF B. LOWENFELS
PRESIDENT AND CHIEF EXECUTIVE OFFICER

September 12, 2001

Senator Torgerson
State Capitol
Room 427
Juneau, AK 99801

Dear Senator Torgerson,

You asked Yukon Pacific to respond to two questions.

1. Please provide section by section comments of the Producers' Proposed Act. Does the Act benefit your project? Do you support the Proposed Act? Why or why not?

Answer: The proffered Alaska Natural Gas Pipeline Act of 2001 does not apply to the TransAlaska Gas System. This LNG project does not meet the definition of the term "Alaska Facilities Gas Project" and therefore any benefits derived from the Act would not apply to the Alaskan LNG project sponsored by Yukon Pacific Corporation.

2. If you do not support he Producer's Proposed Act, are any changes to federal law necessary or useful to expedite the construction and operation of your project to get Alaska natural gas to market? If so, please describe those changes and propose suggested language.

Answer: Yukon Pacific Corporation does not support the legislation proposed by the producers. This legislation attempts to tilt the playing field in their favor to the detriment of other efforts to commercialize North Slope natural gas.

Yukon Pacific followed the requirements of the Alaska Natural Gas Transportation Act and other existing Federal Acts to obtain its permits and authorizations. These are in hand and no further federal action is necessary to loosen environmental procedures and otherwise expedite TAGS.

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2949 SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPLINE, 2001-02

Yukon Pacific notes the lack of a termination clause for the proposed Federal Act raising the specter of complications arising in the future when the producers' overland projects fail to materialize, as was the case with the current Alcan project. For those of us who have watched that project for 20 some odd years and have had to interact with its "expedition" legislation, there can be no question that failure to include a firm termination for the legislation is a most serious mistake and potential impediment to the commercialization of North Slope natural gas

I hope these answers are helpful. We look forward to answering any further questions at the next hearing.

Sincerely,

Jeff Lowenfels

Proposal # ANGTA 1

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress reaffirm that the Alaska Natural Gas Transportation Act (ANGTA) is the prevailing law with respect to a transportation system for delivery of Alaska natural gas to Alaska, the contiguous States, and other markets, and the construction and initial operation of that system.

The Joint Committee on Natural Gas Pipelines also respectfully requests that Congress allow certain amendments to ANGTA to modernize the act without changing the basic nature and general route of the approved transportation system or otherwise preventing or impairing in any significant respect the expeditious construction and initial operation of the transportation system.

Justification for Proposal # ANGTA 1

Before the enactment of ANGTA there were three competitive proposals for an Alaska Natural Gas Transportation System. Specifically those proposals were:

1) the Arctic Gas Project, which proposed an overland pipeline extending from Prudhoe Bay, across the North Slope of Alaska to the Canadian Mackenzie Delta and thence southerly through Canada to the lower forty-eight states;
2) the El Paso LNG Project, which proposed an overland pipeline extending from Prudhoe Bay to Southern Alaska, where the gas would have been liquefied and transported by tankers to terminals in the western United States; and
3) the Alcan Pipeline Project, referred to in Canada as the Alaska Highway Pipeline Project, which proposed an overland pipeline extending from Prudhoe Bay to Fairbanks, Alaska, and thence southeasterly through western Canada to the lower forty-eight states.

All of these proposals were filed under the Natural Gas Act, debated by FERC, and Congress passed ANTGA, which authorized the President to select a route. The President then approved the ALCAN route and entered into a treaty with Canada, which were later confirmed by Congress. The

Canadian Parliament also passed the Northern Pipeline Act, the equivalent of ANGTA. ANGTA was never repealed. In fact, in 1992 the federal inspector recommended that ANGTA be abolished, but Congress rejected that notion.

Proposal # ANGTA 2

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress adopt provisions that prohibit the over-the-top route through the Beaufort Sea as a pipeline route.

Justification for Proposal # ANGTA 2

- The Alaska Legislature has banned this route in Senate Bill 164.
- The House of Representatives in Congress has adopted an amendment in the Energy Bill to ban this route.
- This route seriously decreases the benefits Alaskan's will receive from the development of natural gas.
- The North Slope Borough and the Alaska Eskimo Whaling Captains oppose this route.

Proposal # ANGTA 3

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress create a mechanism for allowing the transparent and fair distribution of the costs allowed to be included in the tariffs associated with a conditioning plant(s).

Justification for Proposal # ANGTA 3

Other producers will likely discover gas downstream from access to a conditioning plant in Prudhoe Bay that will require them to construct an additional conditioning plant. These producers will need to be treated fairly

with regard to tariffs to encourage development and exploration of all North Slope gas resources.

Proposal # ANGTA 4

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to eliminate the Dempster-Lateral route from provisions in ANGTA, if necessary.

Justification for Proposal # ANGTA 4

The original version of ANGTA included approval for the construction of a Dempster-Lateral pipeline to deliver natural gas to market from the Northwest Territories. The Northwest Territories has developed plans for their own pipeline route to Alberta, making the Dempster-Lateral line obsolete.

Proposal # ANGTA 5

The Joint Committee on Natural Gas Pipelines respectfully requests that the Congress pass legislation that limits tariff charges for prior work to compensation for work done that does not have to be duplicated and which is deemed appropriate to the current transportation system.

Justification for Proposal # ANGTA 5

The current owner of the authorizations under ANGTA is Foothills Pipeline Ltd. Previously, Foothills had several partners, which over time have withdrawn from the partnership. The withdrawn partners spent funds in support of the ANGTA route and have filed documents with the FERC to include recovery of those costs in any tariff for transportation of Alaska natural gas. Foothills has been negotiating with the withdrawn partners to

resolve this outstanding liability. However, those negotiations have not been successful to date.

Foothills and its partners should be compensated for the work done in furtherance of the ANGTA system that does not need to be duplicated. If the work needs to be redone or modernized, they should not be entitled to collect for the funds previously expended. Accordingly, the Joint Committee should support this request.

Proposal # A1

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress pass legislation to assure that Alaska have fair and reasonable access to gas produced within the State and to create a joint board consisting of members appointed from the Federal Energy and Regulatory Commission and the Regulatory Commission of Alaska to recommend access and tariffs that affect the state of Alaska.

Justification for Proposal # A1

Unlike the Trans-Alaska Transportation System for oil, the Natural Gas Act does not provide for the Regulatory Commission of Alaska to set rates for gas used in Alaska. Although section 13(b) of ANGTA provides that the state is authorized to ship its royalty gas on the approved system for use within Alaska and to withdraw such gas from the interstate market for use within Alaska, it does not deal specifically with how Alaska delivery points along the line will be approved. Access to gas is necessary for social and economic development of Alaska. Alaska's regulatory commission should be part of a team that determines how intra-state access and rates are determined.

Proposal # A3

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to develop a formula that would allow for the setting of different tariff rates for natural gas distribution points along the route. (HUBS)

Justification for Proposal # A3

Alaska is studying different proposals for usage of natural gas within the state, including several proposals for LNG facilities, a petrochemical plant, several GTL plants, and in-state usage by communities. It is important to be able to set the tariff at different rates to allow these take off points.

Proposal # A4

The Joint Committee on Natural Gas Pipelines respectfully requests that the Congress pass legislation to assure that gas producers that do not have an ownership interest in the pipeline have fair and reasonable access to space on the pipeline and the ability to obtain expansion capacity of the pipeline.

Justification for Proposal # A4

ANGTA originally precluded the Producers from participating in the ownership of the gas pipeline. In 1981, a waiver was sought and obtained by President Reagan to permit the Producers to have an ownership share in the pipeline. Their participation, however, had to be approved by the FERC and could be approved only after consideration of the advice from the Attorney General and upon a finding by FERC that the participation would not (a) be inconsistent with the antitrust laws or (b) in and of itself create restrictions on access to the transportation system for non-owner shippers or restrictions on capacity expansion.

Alaska has much more gas than that contained in known fields. Current estimates provide that there is greater than 100 tcf of gas undiscovered on the Alaska North Slope. Currently, companies are considering exploring for

such gas. If discoveries are made, that gas will need access to the pipeline on fair and reasonable terms. If significant discoveries are made after the initial capacity is filled, the pipeline will need to be expanded and any expansion request needs to be determined on fair and reasonable terms. Accordingly, the law must be clear that the FERC has the authority to make such determinations.

Proposal # AH 1

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to approve a provision for project labor agreements.

Proposal # AH2

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to approve a preference for qualified Alaskan businesses for the construction and maintenance of a natural gas pipeline.

Proposal # T1

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress pass legislation that prohibits tax incentives for LNG from sources outside of North America.

Justification for Proposal # T1

The President and Congress have recommended a variety of incentives as part of a national energy policy. Alaska natural gas is in competition with

LNG imported from foreign sources to supply gas to the lower 48 states. It is the policy of the United States to reduce dependence on foreign energy sources. Accordingly, Congress should not pass any law that gives tax incentives to facilities importing LNG from sources outside North America. Rather, Congress should enact incentives that benefit production from the frontier areas of the United States, including Alaska. Otherwise, United States gas in frontier areas may be stranded.

Proposal # T2

The Joint Committee on Natural Gas Pipelines respectfully requests that the Congress pass legislation providing a tax incentive that allows for an accelerated depreciation schedule of seven years for Alaska natural gas brought to United States markets.

Justification for Proposal # T2

The President and the Congress has recommended a variety of incentives as part of a national energy policy. It is the policy of the United States to reduce dependence on foreign energy sources. Alaska has significant gas resources that can reduce that dependence and bring cleaner burning fuel to United States markets. However, the construction of a pipeline to the lower 48 would cost billions of dollars and involve significant risk. Accordingly, Congress should enact tax incentives, such as accelerated depreciation, investment tax credits, and downside price tax credits that benefit gas production from Alaska.

Subject: Legislative E-News 09-19-01
Date: Wed, 19 Sep 2001 18:54:54 -0800
From: Ken Erickson <Ken_Erickson@Legis.state.ak.us>
Reply-To: majority_press_office@maillists.corecom.net
To: akreporg@maillists.corecom.net

Legislative E-News for September 19, 2001
http://www.akrepublicans.org/22ndleg/subscription2.shtml
ANS Crude: Yesterday = $25.81 Today = $24.70

Pipeline Committee Rejects Producers' Proposed Bill

(ANCHORAGE) - Saying Congress has already established the legal framework for an Alaska-Lower 48 natural gas pipeline, the Joint Committee on Natural Gas Pipelines today rejected federal pipeline legislation proposed by North Slope producers in favor of the 1977 Alaska Natural Gas Transportation Act mandating a southern route.

"A southern route obviously provides the greatest benefit to Alaska and the nation, and Congress realized that when it made ANGTA the vehicle for bringing Alaska gas to market," said Sen. John Torgerson, chairman of the joint pipeline committee. He will convey the Legislature's support for ANGTA, and propose the amendments, on Oct. 2 at a U.S. Senate Energy Committee hearing on the gasline in Washington D.C.

"The joint committee is responsible for representing the Legislature's position to Congress," said Rep. Joe Green, vice chair of the committee. "I feel the proposals we discussed and approved represent Alaska's views on what we'd like to see in any final federal pipeline legislation."

The full text of this press release can be found at:
http://www.akrepublicans.org/22ndleg/press/prtorgerson109192001.shtml

2001 Legislative Accomplishments:
http://www.akrepublicans.org/22ndleg/info/endcontents05082001.shtml

Current Committee Schedules can be found at the link below:
http://www.legis.state.ak.us/basis/hearing_form.asp?session=22

Contact Webmaster(s) mailto:Ken_Erickson@Legis.state.ak.us
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SCOMM

129:5

Alaska State Legislature

Senator John Torgerson, Chair
Phone (907) 260-3041
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Representative Joe Green, Vice Chair
Phone: (907) 269-0123
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Joint Committee on Natural Gas Pipelines

FOR IMMEDIATE RELEASE: Oct. 12, 2001
CONTACT: Sen. John Torgerson, (907) 260-3041; Rep. Joe Green, (907) 269-0123

Torgerson Traveling to Boost Gasline Prospects

(KASILOF) – As part of the Legislature's continuing effort to build international support for a pipeline to bring Alaska's North Slope gas to markets, the chairman of the Joint Committee on Natural Gas Pipelines plans to travel to Canada next week to meet with government and business leaders on the issue.

"We are engaged in a long-term effort to overcome any obstacles to getting Alaska's gas resources to market," Sen. John Torgerson (R-Kasilof), said today. "As that effort continues, it is important to maintain and expand our working relationship with the Canadians who are our neighbors and potential partners in that effort."

Torgerson will travel first to Calgary, Alberta, to deliver the keynote address to the Mackenzie Delta Oil and Gas Development Strategies Conference on Wednesday, Oct. 17. He plans to discuss the history of natural gas projects in Alaska and current projects being considered; Alaska's opposition to an "over the top" pipeline route through Canada's Mackenzie River Delta; and the possibility of using incentives and state ownership in a pipeline to prevent stranding Alaska's gas.

"I also plan to continue to promote my proposal for an International Working Group of officials from Alaska and Western Canadian provinces and territories, that will help us build consensus on issues surrounding delivery of Arctic natural gas to markets," Torgerson said.

The benefits of the working group will also be on the agenda at a Wednesday meeting with Alberta's Minister of Energy, Murray Smith. Torgerson said he hopes to convey to Minister Smith that the working group will help avoid misunderstanding from cross-border communications, and will serve as a forum for the exchange of information on issues of labor employment, in-state gas processing, and U.S. and Canadian environmental standards that might bear upon the gasline project.

In meetings scheduled for Oct. 19 with the Edmonton Chamber of Commerce and the University of Alberta School of Business' Business Advisory Council, Torgerson plans to informally discuss the economic benefits of gas production and strategies our governments can employ to avoid stranding Arctic natural gas. He will also hold meetings with Foothills Pipe Lines Ltd., which holds permits for a southern route pipeline, and with Agrium, a Canadian company that owns and operates a gas-fired ammonia plant in Nikiski.

"Everyone involved in the gasline issue understands the benefits of pipeline development to our northern economies," Torgerson said. "Alaskans and Canadians are 'can-do' people, and I'm confident we can work together to realize the benefits of this project to both of our countries."

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ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

Official Business

Senator John Torgerson, Chair
Senator Rick Halford
Senator Pete Kelly
Senator Johnny Ellis

Representative Joe Green, Vice-Chair
Representative Brian Porter
Representative Scott Ogan
Representative John Davies

Testimony by Senator John Torgerson to the Senate Committee on Energy and Natural Resources
October 2, 2001

Good morning Mr. Chairman and members of the committee. My name is John Torgerson. I chair the Senate Resources Committee and the Joint Committee on Natural Gas Pipelines which is made up of equal members from the House and Senate. One of the responsibilities of this joint committee is to represent the Legislature before Congress on natural gas pipeline issues.

The joint committee met on September 19th and we discussed the Alaska Gas Producer's Pipeline Team's proposed legislation. We unanimously opposed this draft legislation and voted in favor of requesting Congress to reaffirm the Alaska Natural Gas Transportation Act (ANGTA) as the prevailing law. Virtually everything the producers have proposed can be found in ANGTA.

One of our major concerns with the producer's legislation is the fact that it is route neutral, giving them the opportunity to apply for a buried underwater offshore ANWR pipeline route to which Alaska is adamantly opposed.

Session: January – May
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Back in the mid 1970s, there were three pipeline applications filed under the Natural Gas Act, the so-called "over the top" route, the Alaska Highway or Alcan route, and an all Alaska or Liquefied Natural Gas route. To end the route debate, Congress passed the Alaska Natural Gas Transportation Act. Section 7 of this Act required the President to prepare a Decision on an Alaska Natural Gas Transportation System, which he did and which he submitted to Congress on September 22, 1977. The President's Decision was approved by Congress with Public Law 95-158 and modified by Public Law 97-93. The Canadian Parliament then passed its own version of ANGTA known as the Northern Pipeline Act.

Since the President and Congress have not repealed their action in selecting an Alaskan Highway route, ANGTA is still the prevailing law with respect to an Alaskan gas pipeline. Furthermore, an application should not be given consideration if it is filed under the Natural Gas Act since these very same proposals have already been reviewed and a route has been selected.

The Alaska Highway route authorized by Congress and the President is important to Alaskans for the instate jobs, the creation of value added industries along the line and along spur lines to tidewater, a stable revenue stream for our communities and the state, and most importantly, a clean burning energy source for Alaskans to rely on for many years into the future.

A pipeline built in the Beaufort Sea greatly reduces the potential for Alaskans to reap the benefits from our gas. In addition, we believe, and national environmental organizations agree, that the Alaska Highway route is more environmentally sound than a route under the Beaufort Sea.

In our support of ANGTA as the prevailing law, the Joint Committee recognizes that a few changes would be helpful to bring this project into the 21st century. Therefore, we approved twelve proposals that I have submitted in my written testimony for your consideration. In the interest of timing, I would like to highlight a few of the committee's recommendations.

- The first proposal, which I have already addressed, is to reaffirm the Alaska Natural Gas Transportation Act as the prevailing law.
- Adopt the provision in HR 4 to ban the over-the-top route through the Beaufort Sea as a legitimate pipeline route.
- Create a joint board consisting of members appointed from the Federal Energy and Regulatory Commission and the Regulatory Commission of Alaska to insure that Alaska has fair and reasonable access to gas produced within the State.
- Our last two proposals have to do with tax incentives. First we support the language currently in HR 4 allowing for an accelerated depreciation schedule of seven years. Our last proposal could be considered a tax disincentive. Since it is the policy of the United States to reduce our dependence on foreign energy sources, we believe Congress should not pass any law giving tax incentives to Liquefied Natural Gas imported from outside North America. Rather, Congress should give incentives to gas from non-conventional sources and frontier areas within the United States.

As far as other tax incentives are concerned, the producers have not asked for any and they have not shared their financial projections with my committee.

The only thing the producers have mentioned is a need for fiscal certainty in the state's tax regime. I feel we should not begin our negotiations by leading with incentives until we at least verify the profitability of a project.

In closing Mr. Chairman, I would also like to mention that it is important to Alaskan's that the provisions authorizing the exploration and drilling in the Arctic National Wildlife Refuge remain in HR 4. America needs more reliable sources of energy, we have those resources available in Alaska and we stand ready to assist you in delivering this energy to market.

ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

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Representative Joe Green, Vice-Chair
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Alaska Gas Resources

Submitted to Senate Committee on Energy and Natural Resources

Prepared by Staff to Joint Committee on Natural Gas Pipelines

Alaska has huge known gas reserves and unknown discovered gas resources on the North Slope. The Alaska Department of Natural Resources' 2000 Annual Report estimated known gas reserves on the onshore North Slope at over 30 tcf. The Mineral Management Service (MMS) places the number at over 32 tcf onshore with an additional 5 tcf in the offshore. The two agencies estimate about 23 to 26 tcf in the Prudhoe Bay area alone. According to the MMS, these gas reserves "can be considered readily available for export." K. Sherwood, Prospects for Development of Alaska Natural Gas: A Review 8 (MMS 2000)

Regarding potential undiscovered resources, the numbers have varied, but all are substantial. The National Petroleum Council (NPC) estimates that gas resources from new discoveries within Alaska will be about 215 tcf and about 55 tcf from nonconventional gas resources like coalbed methane. Most of this resource is expected to be found in the Alaska Arctic. The MMS forecast for gas in Arctic Alaska is similar to the NPC forecast. The mean forecast is about 160 tcf and the high is about 340 tcf.

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> "Alaska has over 170 tcf of natural gas resources: 26 tcf of proven reserves, 33 tcf of probable reserves, 29 tcf of possible reserves, and speculative resources of over

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80 tcf. The major share of these resources, over 55% of the natural gas reserves, are found on the North Slope. In addition over 93% of the proven gas reserves are found in Prudhoe Bay."

Purvin & Gertz, Alaskan Gas Development Strategies IV-16 (2000)

Just using the 30 tcf of known reserves, a pipeline carrying 2.5bcf/d would have a life expectancy of over 32 years. If the pipeline carried 4 bcf/d, the life expectancy would be over 20 years. But, as shown above, many more discoveries are expected. In fact, at this year's oil and gas lease sale of acreage in the Foothills, the State of Alaska sold the largest amount of acreage at any time in recent history. Most of this acreage was purchased by companies interested in exploring for and producing gas. The interest was generated by increased gas prices and the possibility of a gas pipeline.

State of Alaska

Office of the Governor

Tony Knowles
Governor
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NEWS RELEASE

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FOR IMMEDIATE RELEASE: October 2, 2001 01-219

KNOWLES PUSHES FOR NATIONAL INTEREST GASLINE LEGISLATION

Tells Senate Committee Highway Project Meets National Need for Energy, Jobs

Washington, D.C. – Saying it meets national interests for a secure, substantial, and long-term source of clean energy and would create thousands of needed jobs, Gov. Tony Knowles went before the Senate Energy Committee today to push for federal legislation to start work on the Alaska Highway Natural Gas Pipeline.

"Tapping into America's largest known natural gas reserves of 35 trillion cubic feet, this long-term supply of affordable energy will increase consumer confidence and business investment," Knowles said. "The critical step in realizing this economic and energy boom is strong, creative, and focused national interest legislation that could come from this Committee and this Congress."

No single undertaking will do more to put Americans to work than the Alaska Highway natural gas pipeline project, Knowles told the Senate committee, chaired by New Mexico Sen. Jeff Bingaman, with Alaska Sen. Frank Murkowski the ranking minority member.

"At a time when this nation may well be in a recession and the only news from corporate headquarters is the size of layoffs, this project will provide 30,000 construction, manufacturing, and transportation jobs with a payroll in excess of a billion dollars a year," Knowles said. "At a cost estimated between $15 billion and $20 billion, the 3,500-mile pipeline from the Alaska North Slope to lower 48 markets would be the largest privately funded project in this nation's history and provide natural gas for homes, businesses, and electric generating plants for the next half century."

Knowles said legislation to promote development of the natural gas pipeline must contain three essential components. First, the route must be mandated along the Alaska Highway, as provided for in the 1976 Alaska Natural Gas Transportation Act (ANGTA).

"The route that follows the existing oil pipeline from the Alaska North Slope to Fairbanks and then the Alaska Highway through Canada to Alberta is currently authorized in ANGTA and is part of an international treaty with Canada," Knowles said. "It recognizes the environmental advantage of following existing transportation corridors. It allows vitally important access to the gas for the residents and businesses in Alaska. For

-more-

these reasons, this route has the broadest support among Alaskans of any major project in recent history."

Knowles said serious concerns remain over the proposed alternative route commonly known as the northern or "over the top" route that proceeds 240 miles under the ice-choked Beaufort Sea to the Mackenzie River Delta.

"If the producers opt for this northern route, there would be years, if not decades, of fighting from indigenous peoples, environmental groups, and Alaska's business and political leadership," Knowles said. "There also could be potential litigation for claims of rights allegedly granted by Congress two decades ago in the ANGTA regime. The only route that can provide a timely beginning of this national interest project is the already approved Alaska Highway route and current legislation must reflect that."

Secondly, Knowles said the legislation must help build American industry and create jobs. Knowles called incentives for the use of American and Canadian steel; a project labor agreement to attract the highly skilled workers in organized labor to build and maintain the pipeline; and provisions to address employment needs in Alaska, the state that will supply the nation this resource. These would include a preference for the hiring of Alaskans and Alaska Natives, and the use of Alaska businesses in accordance with applicable state and federal law.

Lastly, Knowles called for economic incentives to attract the private capital to the project which when completed will substantially add to the national treasury. This would include accelerated depreciation at a 7-year rather than a 15-year rate; investment tax credits which as used in other federal projects could shave $2 billion off the cost of the project; and a production gas tax credit to provide investor confidence by allowing a tax credit for natural gas production tied to a floor price of gas.

"Since completion of the trans-Alaska oil pipeline nearly 25 years ago, Alaska has been proud to be America's energy storehouse," Knowles said. " We have supplied up to a quarter of America's domestic oil production from the nation's two largest oil fields. By working with this committee, the entire Congress, and the national administration, Alaska will continue to help meet America's oil needs from the Arctic National Wildlife Refuge, the National Petroleum Reserve-Alaska, and other fields.

"Yet just a pipeline away, North American demand for natural gas for electrical generation, industry, and transportation is growing," Knowles concluded. "The United States and Canada already consume about 24 trillion cubic feet of natural gas a year, with that projected to soar to 30 trillion cubic feet by the decade's end. Alaska can help meet this demand, while giving our sagging national economy a sorely needed shot in the arm.

"The State of Alaska and my administration stand ready to assist you and the national administration in crafting a sensible national energy policy that continues to rely on Alaska as our nation's energy storehouse," Knowles told the Senate Energy Committee.

While in the nation's capital, the Governor is also lobbying key senators on oil and gas development in the Arctic National Wildlife Refuge and talking to U.S. and Canadian media about Alaska development issues.

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OCT 11 2001

MEMORANDUM

To: Members of the Joint Committee on Natural Gas Pipelines

From: Senator Torgerson, Chairman Darwin Peterson for Sen. Torgerson

Re: Washington D.C. trip

Date: October 5, 2001

I have assembled a packet of information for all members of the Pipeline Committee that I think will be helpful for those interested in the recent hearing on an Alaskan natural gas pipeline held in Washington D.C. by the Senate Committee on Energy and Natural Resources.

Enclosed you will find:

1) A copy of my testimony and backup material submitted to the committee prior to the hearing. Members also received my testimony via email from my staff on October 1st.
2) A copy of each witness's oral testimony delivered to the committee.
3) Notes prepared by my staff describing the question and answer portions of the committee hearing.

If you or your staff have any questions, please don't hesitate to contact my office.

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October 1, 2001

The Honorable Jeff Bingaman
United States Senator, New Mexico
Committee on Energy and Natural Resources
SD-312
United States Senate
Washington, DC 20510-3102

Dear Chairman Bingaman:

Thank you for the opportunity to testify before the Senate Committee on Energy and Natural Resources about the transportation of natural gas from Alaska to markets in Alaska and the lower 48. I am providing the Committee with 75 copies of the following materials as my testimony:

1. Oral Testimony of Senator John Torgerson
2. Twelve Proposals of the Joint Committee on Natural Gas Pipelines
3. Alaska Gas Resources
4. The Importance of the Alaska Natural Gas Transportation Act of 1976 Today

If you have any questions, feel free to contact me at your convenience.

Sincerely,

Senator John Torgerson

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Testimony by Senator John Torgerson to the Senate Committee on Energy and Natural Resources
October 2, 2001

Good morning Mr. Chairman and members of the committee. My name is John Torgerson. I chair the Senate Resources Committee and the Joint Committee on Natural Gas Pipelines which is made up of equal members from the House and Senate. One of the responsibilities of this joint committee is to represent the Legislature before Congress on natural gas pipeline issues.

The joint committee met on September 19th and we discussed the Alaska Gas Producer's Pipeline Team's proposed legislation. We unanimously opposed this draft legislation and voted in favor of requesting Congress to reaffirm the Alaska Natural Gas Transportation Act (ANGTA) as the prevailing law. Virtually everything the producers have proposed can be found in ANGTA.

One of our major concerns with the producer's legislation is the fact that it is route neutral, giving them the opportunity to apply for a buried underwater offshore ANWR pipeline route to which Alaska is adamantly opposed.

Back in the mid 1970s, there were three pipeline applications filed under the Natural Gas Act, the so-called "over the top" route, the Alaska Highway or Alcan route, and an all Alaska or Liquefied Natural Gas route. To end the route debate, Congress passed the Alaska Natural Gas Transportation Act. Section 7 of this Act required the President to prepare a Decision on an Alaska Natural Gas Transportation System, which he did and which he submitted to Congress on September 22, 1977. The President's Decision was approved by Congress with Public Law 95-158 and modified by Public Law 97-93. The Canadian Parliament then passed its own version of ANGTA known as the Northern Pipeline Act.

Since the President and Congress have not repealed their action in selecting an Alaskan Highway route, ANGTA is still the prevailing law with respect to an Alaskan gas pipeline. Furthermore, an application should not be

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The Alaska Highway route authorized by Congress and the President is important to Alaskans for the instate jobs, the creation of value added industries along the line and along spur lines to tidewater, a stable revenue stream for our communities and the state, and most importantly, a clean burning energy source for Alaskans to rely on for many years into the future.

A pipeline built in the Beaufort Sea greatly reduces the potential for Alaskans to reap the benefits from our gas. In addition, we believe, and national environmental organizations agree, that the Alaska Highway route is more environmentally sound than a route under the Beaufort Sea.

In our support of ANGTA as the prevailing law, the Joint Committee recognizes that a few changes would be helpful to bring this project into the 21st century. Therefore, we approved twelve proposals that I have submitted in my written testimony for your consideration. In the interest of timing, I would like to highlight a few of the committee's recommendations.

- The first proposal, which I have already addressed, is to reaffirm the Alaska Natural Gas Transportation Act as the prevailing law.
- Adopt the provision in HR 4 to ban the over-the-top route through the Beaufort Sea as a legitimate pipeline route.
- Create a joint board consisting of members appointed from the Federal Energy and Regulatory Commission and the Regulatory Commission of Alaska to insure that Alaska has fair and reasonable access to gas produced within the State.
- Our last two proposals have to do with tax incentives. First we support the language currently in HR 4 allowing for an accelerated depreciation schedule of seven years. Our last proposal could be considered a tax disincentive. Since it is the policy of the United States to reduce our dependence on foreign energy sources, we believe Congress should not pass any law giving tax incentives to Liquefied Natural Gas imported from outside North America. Rather, Congress should give incentives to gas from non-conventional sources and frontier areas within the United States.

As far as other tax incentives are concerned, the producers have not asked for any and they have not shared their financial projections with my committee. The only thing the producers have mentioned is a need for fiscal certainty in the state's tax regime. I feel we should not begin our negotiations by leading with incentives until we at least verify the profitability of a project.

In closing Mr. Chairman, I would also like to mention that it is important to Alaskan's that the provisions authorizing the exploration and drilling in the Arctic National Wildlife Refuge remain in HR 4. America needs more reliable sources of energy, we have those resources available in Alaska and we stand ready to assist you in delivering this energy to market.

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12 Proposals on Federal Legislation

Proposal # 1

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress reaffirm that the Alaska Natural Gas Transportation Act (ANGTA) is the prevailing law with respect to a transportation system for delivery of Alaska natural gas to Alaska, the contiguous States, and other markets, and the construction and initial operation of that system.

The Joint Committee on Natural Gas Pipelines also respectfully requests that Congress allow certain amendments to ANGTA to modernize the act without changing the basic nature and general route of the approved transportation system or otherwise preventing or impairing in any significant respect the expeditious construction and initial operation of the transportation system.

Justification for Proposal # 1

Before the enactment of ANGTA there were three competitive proposals for an Alaska Natural Gas Transportation System. Specifically those proposals were:

1) the Arctic Gas Project, which proposed an overland pipeline extending from Prudhoe Bay, across the North Slope of Alaska to the Canadian Mackenzie Delta and thence southerly through Canada to the lower forty-eight states;
2) the El Paso LNG Project, which proposed an overland pipeline extending from Prudhoe Bay to Southern Alaska, where the gas would have been liquefied and transported by tankers to terminals in the western United States; and
3) the Alcan Pipeline Project, referred to in Canada as the Alaska Highway Pipeline Project, which proposed an overland pipeline

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extending from Prudhoe Bay to Fairbanks, Alaska, and thence southeasterly through western Canada to the lower forty-eight states.

All of these proposals were filed under the Natural Gas Act, debated by FERC, and Congress passed ANGTA, which authorized the President to select a route. The President then approved the ALCAN route and entered into a treaty with Canada, which were later confirmed by Congress. The Canadian Parliament also passed the Northern Pipeline Act, the equivalent of ANGTA. ANGTA was never repealed. In fact, in 1992 the federal inspector recommended that ANGTA be abolished, but Congress rejected that notion.

Proposal # 2

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress adopt provisions that prohibit the over-the-top route through the Beaufort Sea as a pipeline route.

Justification for Proposal # 2

- The Alaska Legislature has banned this route in Senate Bill 164.
- The House of Representatives in Congress has adopted an amendment in the Energy Bill to ban this route.
- This route seriously decreases the benefits Alaskan's will receive from the development of natural gas.
- The North Slope Borough and the Alaska Eskimo Whaling Captains oppose this route.

Proposal # 3

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress create a mechanism for allowing the transparent and fair distribution of the costs allowed to be included in the tariffs associated with a conditioning plant(s).

Justification for Proposal # 3

Other producers will likely discover gas downstream from access to a conditioning plant in Prudhoe Bay that will require them to construct an additional conditioning plant. These producers will need to be treated fairly with regard to tariffs to encourage development and exploration of all North Slope gas resources.

Proposal # 4

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to eliminate the Dempster-Lateral route from provisions in ANGTA, if necessary.

Justification for Proposal # 4

The original version of ANGTA included approval for the construction of a Dempster-Lateral pipeline to deliver natural gas to market from the Northwest Territories. The Northwest Territories has developed plans for their own pipeline route to Alberta, making the Dempster-Lateral line obsolete.

Proposal # 5

The Joint Committee on Natural Gas Pipelines respectfully requests that the Congress pass legislation that limits tariff charges for prior work to compensation for work done that does not have to be duplicated and which is deemed appropriate to the current transportation system.

Justification for Proposal # 5

The current owner of the authorizations under ANGTA is Foothills Pipeline Ltd. Previously, Foothills had several partners, which over time have withdrawn from the partnership. The withdrawn partners spent funds in support of the ANGTA route and have filed documents with the FERC to include recovery of those costs in any tariff for transportation of Alaska natural gas. Foothills has been negotiating with the withdrawn partners to resolve this outstanding liability. However, those negotiations have not been successful to date.

Foothills and its partners should be compensated for the work done in furtherance of the ANGTA system that does not need to be duplicated. If the work needs to be redone or modernized, they should not be entitled to collect for the funds previously expended. Accordingly, the Joint Committee should support this request.

Proposal # 6

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress pass legislation to assure that Alaska have fair and reasonable access to gas produced within the State and to create a joint board consisting of members appointed from the Federal Energy and Regulatory Commission and the Regulatory Commission of Alaska to recommend access and tariffs that affect the state of Alaska.

Justification for Proposal # 6

Unlike the Trans-Alaska Transportation System for oil, the Natural Gas Act does not provide for the Regulatory Commission of Alaska to set rates for gas used in Alaska. Although section 13(b) of ANGTA provides that the state is authorized to ship its royalty gas on the approved system for use within Alaska and to withdraw such gas from the interstate market for use within Alaska, it does not deal specifically with how Alaska delivery points along the line will be approved. Access to gas is necessary for social and economic development of Alaska. Alaska's regulatory commission should be part of a team that determines how intra-state access and rates are determined.

Proposal # 7

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to develop a formula that would allow for the setting of different tariff rates for natural gas distribution points along the route. (HUBS)

Justification for Proposal # 7

Alaska is studying different proposals for usage of natural gas within the state, including several proposals for LNG facilities, a petrochemical plant, several GTL plants, and in-state usage by communities. It is important to be able to set the tariff at different rates to allow these take off points.

Proposal # 8

The Joint Committee on Natural Gas Pipelines respectfully requests that the Congress pass legislation to assure that gas producers that do not have an ownership interest in the pipeline have fair and reasonable access to space on the pipeline and the ability to obtain expansion capacity of the pipeline.

Justification for Proposal # 8

ANGTA originally precluded the Producers from participating in the ownership of the gas pipeline. In 1981, a waiver was sought and obtained by President Reagan to permit the Producers to have an ownership share in the pipeline. Their participation, however, had to be approved by the FERC and could be approved only after consideration of the advice from the Attorney General and upon a finding by FERC that the participation would not (a) be inconsistent with the antitrust laws or (b) in and of itself create restrictions on access to the transportation system for non-owner shippers or restrictions on capacity expansion.

Alaska has much more gas than that contained in known fields. Current estimates provide that there is greater than 100 tcf of gas undiscovered on the Alaska North Slope. Currently, companies are considering exploring for such gas. If discoveries are made, that gas will need access to the pipeline on fair and reasonable terms. If significant discoveries are made after the initial capacity is filled, the pipeline will need to be expanded and any expansion request needs to be determined on fair and reasonable terms. Accordingly, the law must be clear that the FERC has the authority to make such determinations.

Proposal # 9

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to approve a provision for project labor agreements.

Proposal # 10

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to approve a preference for qualified Alaskan businesses for the construction and maintenance of a natural gas pipeline.

Proposal # 11

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress pass legislation that prohibits tax incentives for LNG from sources outside of North America.

Justification for Proposal # 11

The President and Congress have recommended a variety of incentives as part of a national energy policy. Alaska natural gas is in competition with LNG imported from foreign sources to supply gas to the lower 48 states. It is the policy of the United States to reduce dependence on foreign energy sources. Accordingly, Congress should not pass any law that gives tax incentives to facilities importing LNG from sources outside North America. Rather, Congress should enact incentives that benefit production from the frontier areas of the United States, including Alaska. Otherwise, United States gas in frontier areas may be stranded.

Proposal # 12

The Joint Committee on Natural Gas Pipelines respectfully requests that the Congress pass legislation providing a tax incentive that allows for an accelerated depreciation schedule of seven years for Alaska natural gas brought to United States markets.

Justification for Proposal # 12

The President and the Congress has recommended a variety of incentives as part of a national energy policy. It is the policy of the United States to reduce dependence on foreign energy sources. Alaska has significant gas resources that can reduce that dependence and bring cleaner burning fuel to United States markets. However, the construction of a pipeline to the lower 48 would cost billions of dollars and involve significant risk. Accordingly, Congress should enact tax incentives, such as accelerated depreciation, investment tax credits, and downside price tax credits that benefit gas production from Alaska.

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Submitted to Senate Committee on Energy and Natural Resources

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Regarding potential undiscovered resources, the numbers have varied, but all are substantial. The National Petroleum Council (NPC) estimates that gas resources from new discoveries within Alaska will be about 215 tcf and about 55 tcf from nonconventional gas resources like coalbed methane. Most of this resource is expected to be found in the Alaska Arctic. The MMS forecast for gas in Arctic Alaska is similar to the NPC forecast. The mean forecast is about 160 tcf and the high is about 340 tcf.

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Just using the 30 tcf of known reserves, a pipeline carrying 2.5bcf/d would have a life expectancy of over 32 years. If the pipeline carried 4 bcf/d, the life expectancy would be over 20 years. But, as shown above, many more discoveries are expected. In fact, at this year's oil and gas lease sale of acreage in the Foothills, the State of Alaska sold the largest amount of acreage at any time in recent history. Most of this acreage was purchased by companies interested in exploring for and producing gas. The interest was generated by increased gas prices and the possibility of a gas pipeline.

THE IMPORTANCE OF THE ALASKA NATURAL GAS TRANSPORTATION ACT OF 1976 TODAY

Submitted by Senator John Torgerson

I. The Alaska Natural Gas Transportation Act of 1976 provided for expedited procedures to construct a gas pipeline built when the Lower 48 required gas.

A. Delayed by litigation, the oil pipeline from Prudhoe Bay was only expedited by an act of Congress and the President.

In the winter of 1967-68, a wildcat rig drilling the Prudhoe Bay State Well No. 1 discovered the field that has become known as Prudhoe Bay field located on the Alaska North Slope (ANS). The discovery turned out to be the largest petroleum reserve on the North American continent, estimated to contain over 25 tcf of original gas in place and 25 billion barrels of oil in place.

In 1969, the State of Alaska held a lease sale in the area of Prudhoe Bay and received almost $1 billion in lease bonuses. Shortly thereafter, the three major leaseholders, Arco (now Phillips), BP and Exxon, announced their intention to build an oil pipeline from Prudhoe Bay to a site on the Gulf of Alaska. The pipeline, known as the Trans-Alaska Pipe Line System or TAPS, became entangled in legal and environmental disputes until November of 1973. Then Congress and the President approved the construction plan and provided for expedited procedures. Construction started immediately thereafter and by June of 1977, the TAPS was ready to flow oil.

B. Since Congress was concerned that a gas pipeline would be delayed like the oil pipeline, it passed the Alaska Natural Gas Transportation Act.

The regulation of the gas industry in the lower 48 began in 1938 with the passage of the Natural Gas Act (NGA). The NGA created the predecessor of the Federal Regulatory Commission (FERC) and gave it power to regulate interstate natural gas pipelines, including the ability to regulate prices at the wellhead. Price volatility and gas supply shortages in parts of the country ensued. Following the oil embargo of 1973, there were many shortages and curtailments of gas deliveries. Some thought that Prudhoe Bay gas could alleviate the situation.

In March of 1974, a partnership known as "Arctic Gas" filed an application to construct a pipeline from Prudhoe Bay through ANWR, and then through the MacKenzie Delta to move gas from the ANS to United States and Canadian markets (Northern route). The application was filed with FERC's predecessor and the National Energy Board (NEB) of Canada. Shortly thereafter in September 1974, another group called "El Paso" filed a competing application. El Paso planned to build a gas pipeline adjacent to TAPS to Valdez, liquefy the gas, and ship it to California by LNG tanker (LNG route). There the LNG would be regasified and shipped to consumers through existing pipelines.

In 1975, the FERC's predecessor and the NEB conducted massive hearings. In July of 1976, a third group called the "Alcan Group" filed yet another competing application. The Alcan Group planned to build a pipeline along an existing utility corridor, the Alaska Highway, through the Yukon Territory into U.S. markets (Alcan route).

The United States Congress recognized the potential for delay inherent in the normal NGA procedures for a project of this magnitude. Congress was especially concerned given the shortages of natural gas. So in October of 1976, Congress passed the Alaska Natural Gas Transportation Act of 1976 (ANGTA) to expedite construction and initial operation of a pipeline to carry ANS gas to the lower 48. The ANGTA terminated all proceedings before the FERC's predecessor and required that the President expeditiously select a route. The ANGTA also provided for limited judicial review and created a new office, the Office of the Federal Inspector (OFI) to coordinate government activities relating to the ANS pipeline.

In the meantime under the Trans-Alaska Pipeline Act, Congress had authorized the President to meet with Canada and discuss its willingness to build a pipeline for Alaska gas across Canada. During discussions, Canada indicated that they were prepared to consider a general agreement as opposed to a particular agreement. Negotiations ensured leading to the Transit Pipeline Treaty, which was signed in January of 1977 and entered into force in September of 1977.

As required by the ANGTA, the FERC's predecessor rejected the LNG route and recommended either the ANWR or the Alcan route. Also as required, many agencies commented on the predecessor's recommendation, raising important questions regarding every major element of the recommendation. In July of 1977, the NEB made its decision regarding an overland route and rejected the northern route, finding it to be "environmentally unacceptable."

That summer Canadian and United States negotiators met to enable the President to make an informed decision. After intensive negotiations, President Carter and Prime Minister Trudeau announced that the countries had a reach an "Agreement on Principles" on a joint project to transport Alaska and Canadian gas. The Agreement was signed in September 1977. The agreement endorsed the Alcan route and selected the operators for the Canadian and United States portions. The Agreement has a term of 35 years and continues beyond 2012 unless terminated on one year's notice by either party.

Two days after the Agreement was signed, on September 22, 1977, the President issued his Decision and Report to Congress as required by ANGTA. He determined that the Alcan route was the most economical and environmentally sound means to get Alaska gas to market quickly. On November 2, 1977, the Congress passed a resolution ratifying the President's Decision. Thus, the Alcan roue became the designated route under United States law.

In December 1977, the FERC issued certificates to the Alcan route's sponsors. In April of 1978, the Canadian Parliament passed the Northern Pipeline Act. This act granted a certificate to the sponsors of the Alcan route for the Canadian portion of the route.

C. ANGTA has specific provisions designed to expedite the construction and initial operation of a pipeline to bring gas from Alaska to the lower 48 and insure that Alaskans have a right to use the gas in-state that can be used today.

When Congress passed ANGTA, it fully intended to pass a bill that could expedite the construction of pipeline to bring Alaska gas to market. Given that a route and an operator have already been selected, the following summarizes provisions that are relevant today and which can be used to expedite a gas pipeline from Alaska.

Section 3 set forth that ANGTA's very purpose: to expedite construction of an Alaskan gasline:

> "The purpose of this chapter is to provide the means for making a sound decision as to the selection of a transportation system for delivery of Alaska natural gas to the [Lower 48] States ... and ... to expedite its construction and initial operation ...."

Section 5 advances this purpose by creating a new independent agency, the Office of the Federal Inspector (OFI), to coordinate all federal activities related to the pipeline, and for assuring timely, efficient, and environmentally construction. In 1992, Congress abolished the OFI. However, Congress transferred all of the functions and authority to the Secretary of Energy. The President's NEPD Group recommended that the President issue an Executive Order to rationalize permitting for energy production in an environmentally sound manner by directing federal agencies to expedite permits and other federal actions, and to coordinate their efforts. The Alaska legislature believes that the combination of the authority in the Secretary of Energy and an Executive Order by the President would be adequate to insure the federal agencies coordinate and expedite their actions so we have not asked for reinstitution of the OFI.

Section 8(g)(1) provides a mechanism to update any problem with ANGTA. The section provides that at any time the President finds that any provision of law applicable to actions by federal agents require a waiver of law to permit expeditious construction and initial operation of the approved transportation system, the President may submit a waiver to both Houses of Congress. This section was used in 1981 when President Reagan submitted certain waivers to Congress.

Section 9 deals with issuance of any certificates, right-of-way, permit, lease, or other authorization (collectively "authorizations") necessary or related to the construction and initial operation of the transportation system. It says that federal officers and agencies shall issue them at the earliest practicable date. Further it provides that such actions shall take precedence over any similar applications or requests.

Section 9 also provides that any federal officer or agency may amend or abrogate any term or condition included in the authorizations. The only limitations are that the actions cannot compel a change in the basic nature and general route or otherwise prevent or impair the expeditious construction and initial operation of such transportation system.

Section 10 limits judicial review. Claims must be brought within shortened periods. Claims are limited to constitutional violations or to authority issues. Claims must be filed in Court of Appeals for the District of Columbia. Any claim takes precedence over other matters to the greatest extent practicable.

Of particular importance to the State of Alaska is Section 9(b) of ANGTA. This section lays to rest any argument that the gas that belongs to the state as its "birthright" can by pass it.

> "The State of Alaska is authorized to ship its royalty gas on the approved transportation system for use within Alaska and, to the extent it contracts for the sale of royalty gas so provide, to withdraw such gas from the interstate market for use within Alaska; the [Federal Energy Regulatory Commission] shall issue all authorizations necessary to effectuate such shipment and withdrawal ...."

The President's Decision also recognized the importance to Alaska that it be able to use the gas in-state.

> "Furthermore, the State will be able to utilize the pipeline for natural gas distribution and development with the State. Prudhoe Bay gas, including the State of Alaska's royalty gas, will be made available to local Alaskan communities along the route of the Alcan Pipeline System. Installation of additional pipeline facilities connecting with the Alcan system could provide natural gas to other areas of the State, particularly the Cook Inlet region and Southeastern Alaska, and thus supply the energy base required for long-term economic development. The Alcan system also will offer a readily accessible transportation service for a number of potential Alaska gas reserves located in interior Alaska, Cook Inlet and the Gulf of Alaska."

Decision at 270. Alaskans need to be assured that they will get the benefit of their gas to provide for the economic development of the state.

South-central Alaska, which includes Anchorage, other urban areas, and industrial complexes, currently uses about 220 bcf a year of natural gas. That gas comes from gas reserves in the Cook Inlet in the southern part of South-central. The reserves to production ratio has been rapidly declining and the MMS has recognized that unless new reserves are found, the Cook Inlet will be out of gas in the next ten years or so. The citizens of South-central have long envisioned a spur pipeline, as discussed in the President's Decision, to Cook Inlet area. Without such a line, Alaska citizens literally may be freezing in the dark while other others are kept warm and lighted with Alaska's

gas. Accordingly, the Joint Committee has recommended certain proposals to insure Alaska's active participation in deciding when and how Alaska gas should be used in-state. See Proposals # 6 & 7.

D. ANGTA has been repeatedly reaffirmed and it has the flexibility to be modernized.

Because demand in the lower 48 for natural gas changed in the late 1970s and early 1980s, the Alaska portion of the ANGTS was not built Twice, Congress has reaffirmed its support for the ANGTA and the selected route. The President has also reaffirmed ANGTA. . ANGTA remains the law of land and can be modernized to deal with current conditions.

In 1980, Canada needed assurances reaffirming the commitment of the United States government to go forward with the Canadian portion of the ANGTS. On July 1, 1980, Congress passed a Joint resolution that reaffirmed its support. The resolution stated "it is the sense of Congress that the [ANGTS] System remains an essential part of securing this nation's energy future and, as such, enjoys the highest level of Congressional support for its expeditious construction and operation ,,,,"

In 1987, Yukon Pacific was seeking a finding allowing the export of Alaska gas. Canadian officials expressed concern about such a finding on the ANGTS. In January of 1988, President Reagan issued a finding granting the exception. However, he also declared: "I want to reaffirm our support for the special regulatory treatment of the of the [Canadian] portion of the ANGTS, including the minimum revenue stream guarantees."

In 1992, the OFI issued a report recommending that United States abandon its support for the completion of the ANGTS, Congress repealing ANGTA, terminate the treaties and agreements with Canada, and abolish the OFI. The ANGTS did not oppose the elimination of the OFI. They did, however, oppose the other recommendations. The government of Canada objected to most of the recommendations as contrary to the obligations of the United States. The then chairman of the Senate Committee on Energy and Natural Resources also opposed the recommendations. Ultimately, Congress transferred the OFI's authorities to the Secretary of Energy, but the other recommendations were rejected.

Some have asserted that the ANGTA cannot be modernized. For example, the pipeline diameter and pressure constraints may need to be change from that discussed in the President's decision. These types of modifications will improve the efficiency, safety and environmental impact of the pipeline. Because these types of changes would not involve a change to the "basic nature" to the route, the appropriate federal agencies have authority to amend the previous approvals. As noted above, Section 9 of ANGTA specifically authorizes such amendments. If a change to the basic nature was necessary, the ANGTA also provides the President can submit waivers to the Congress for approval. Nevertheless, to clear up any uncertainty regarding this issue, Congress could make clear that federal agencies have authority to modernize the route.

II. Other than allowing the construction of an over the top route and the selection of a new operator, the Producers' proposed enabling legislation is not materially different from the ANGTA.

The Joint Committee has reviewed the Producers' proposed legislation and believes that in terms of provisions for expediting construction and an initial operation, the proposed legislation is duplicative of ANGTA. The only purpose that would be served by the producers' legislation is to renew the route and operator debate that was resolved by ANGTA. Rather than clarify the situation, the producers' proposed legislation would create confusion and chaos with ANGTA (which is not repealed by the proposed legislation) and with Canada's version of ANGTA, the Northern Pipeline Act. Although producers say the ANGTS can forward because their proposed legislation does not terminate ANGTA, as practical matter, the ANGTS would be dead. There is no way two gaslines will be built from Alaska.

The Producers' legislation would open up the possibility of a pipeline along an over the top route. The producers themselves have said they would not build along a route that the State of Alaska did not want. I am hear to tell that Alaskans do not want that route. First, it was not the preferred route in ANGTA. Second, our Alaska legislature passed a bill, SB 164, prohibiting the permitting the over the top across state lands. Third, our governor has expressed his view supporting an Alcan route. Fourth, the North Slope Borough oppose the route and the Alaska Eskimo Whaling Commission has passed a resolution strongly opposing an over the top. Fifth, conservation groups oppose the over the top route. Sixth, our entire congressional delegation opposes the route. Alaskans opposition to the over the top route has been supported by the United States House of Representatives which included in HR 4 a provision banning the route and environmental group. There is simply no way Alaskans will allow the gas, which is owned by the state and its birthright, to be extracted and shipped out of the state without a line running through the state. As Senator Ted Stevens told the Joint Committee, Alaskans would rather see the gas left in the ground than go over the top.

III. The Joint Committee believes that ANGTA prevails over the Natural Gas Act.

A. Congress should reaffirm ANGTA as the prevailing law to put to rest questions raised by the Producers and federal agencies about ANGTA.

The Joint Committee believes that in passing the ANGTA, approving by resolution the President's decision selecting an Alcan route under section 7 of the ANGTA, and reaffirming ANGTA and the Alcan route, Congress has demonstrated its intent that ANGTA prevails over an application over the Natural Gas Act (NGA)and a competing proposal to construct a different pipeline cannot be considered under the NGA. Nevertheless, some have pondered the question: "To what extent can the FERC consider a new proposal that varies from the ANGTS that was previously approved by the

President and Congress, including consideration of proposals under section 7 of the NGA?" Although my view may be colored because I am a legislator, I cannot believe that agencies are even questioning what I believe was this legislative body's clear intent. To put this issue to bed, Congress could expedite the process by reaffirming that ANGTA controls and that an application under the NGA cannot be considered until after the ANGTA approved line is built.

B. To expedite the construction and initial operation of an Alaska gasline, Congress could update some of ANGTA's provisions.

As discussed above, the Joint Committee believes that section 9 of the ANGTA allows the line to be updated so long as a proposed amendment do not change the basic nature and general route of the transportation system. Nevertheless, there are provisions that Congress might consider that could benefit the ANGTS, enhance the possibility of in-state deliveries for Alaskans, and could provide more gas for Alaska and the nation, which are contained in Proposals that the Joint Committee has submitted to you today. In this section, I discuss two issues that have been raised as possible impediments to the construction of ANGTS.

The first is what has been referred to as the "withdrawn partner contingent liability". The partnership that was selected to build the Alcan route originally had eleven partners. Today only two remain. We have been told that the partnership actually spent around $280 million to advance the Alcan route. On the most recent FERC Form No. 2, which is filed for ratemaking purposes, this amount had grown to $3.7 billion because of the 14% interest allowed under FERC accounting. The Alcan route (or any other route for that matter) would clearly not be economical if it, in essence, started $3.7 billion in the hole.

The two remaining partners, Foothills and Transcanada, say that this contingent liability will not impede construction and operation of the Alcan route. No monies will be paid to the withdrawn partners unless the line is built and payment can be paid without "undue hardship to the Partnership." Accordingly, Foothills and Transcanada say that the withdrawn partners have strong incentive to work cooperatively to resolve the matter.

Nevertheless, they have not resolved the matter to date. The Joint Committee discussed the matter and decided that the partnership should be compensated for past work, but only if the work does not have to duplicated now and the FERC decides that it is appropriate for inclusion in a modern ANGTS. See Proposal #5 attached.

The second possible impediment concerns the partnerships' obligation to construct a Dempster Lateral pipeline to connect gas in the MacKenzie Delta with the ANGTS after the Alaska portion of the ANGTS is built. This requirement is no longer necessary because various parties have filed applications with the NEB to bring MacKenzie Delta gas south along the MacKenzie River and south. They say that this route would be cheaper and no other parties have shown an interest in a Dempster Lateral route. Accordingly, the Joint Committee respectfully requests Congress grant the FERC the authority to eliminate the Dempster Lateral from ANGTS, if necessary. See Proposal #4.

ALASKA STATE LEGISLATURE

Senator John Torgerson

Official Business

- Chair, Senate Community & Regional Affairs Committee
- Chair, Senate Resources Committee
- Chair, Joint Committee on Natural Gas Pipelines

Fax

To:	Joint Committee on Natural Gas Pipelines	**From:**	Darwin Peterson, Sen. Torgerson's office
Fax:		**Pages:**	10 w/ cover
Phone:		**Date:**	10/11/01
Re:	Federal Energy Bill	**CC:**	

Members of the Joint Committee on Natural Gas Pipelines,

I have attached a letter we received today from C.J. Zane with the law firm of Dyer, Ellis & Joseph, the committee's contracted firm in D.C. Mr. Zane explains the recent activity regarding the energy bill. Also included are news articles and Senator Murkowski's recent floor speech.

Sincerely,

Darwin Peterson

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MEMORANDUM

TO : The Honorable John Torgerson

FROM : C. J. Zane

DATE : October 11, 2001

RE : Energy Bill

Senator, you probably picked up on most of this already but I wanted to forward some articles and give you a short note about what we hear regarding the energy bill. With the declaration by Senators Landrieu and Akaka that they would favor an ANWR opening provision in the energy bill, Senator Daschle has pulled the bill from the Energy and Natural Resources Committee and said he will bring an energy package directly to the floor. The Democrats say the reason for bypassing the committee is due to the multiple committee jurisdictions that such a wide sweeping bill touches upon and that having the bill referred to multiple committees will take too long. However, the real reason appears to be to avoid having ANWR added in the bill in the Energy and Natural Resources Committee. In addition, most folks on the Hill believe that Daschle has given anything but a firm commitment to bring a bill to the floor. He has said things like he wants to try to complete an energy bill this session, but that finishing the Appropriations bills, completing an economic stimulus package, resolving the anti-terrorism and airport and airline security bills, are all top priorities and must be finished before there would be floor time for an energy package. In short, we may still be getting the slow roll, but Daschle is positioning himself and the Dems to move a bill quickly if they perceive the American people want one and/or if events in the "war on terrorism" further propel the need for a bill.

Mike Menge, Dan Kish and Justin Stiefel all say that even if Daschle is doing the "slow roll", the Delegation will continue to look to alternative vehicles to move ANWR. Such vehicles include individual appropriations bills or the "mini-omnibus" appropriations bill (containing the last three or four appropriations bills), the economic stimulus package or even the anti-terrorism package. With or without an specific energy bill per se, the Delegation favors including some language on the gas line, but it's not clear at this point what that language would be. It does seem to us, at least, that the Delegation, despite some mixed comments lately, favors the exiting ANGTA route and they can be convinced to support language clarifying the primacy of the existing route or to do nothing if that ends up helping the existing route. All appear to agree that resolving the withdrawn partner issue and getting U.S. firms like Enron and Williams in the deal will do much to create momentum for the ANGTA route, both legislatively if needed, and at the White House.

I have included for your information several articles and Murkowski's floor statement from yesterday. Please call Duncan Smith or me if you have any questions. Thanks.

Attachments (4)

ANWR -- (Senate - October 10, 2001)

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Mr. MURKOWSKI. Mr. President, I call attention to some of the comments made in this Chamber earlier today relative to the issue of taking up a national energy security bill before this

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body. I spoke a little earlier on the floor today and indicated that, clearly, it is in the national interest that we in the Senate proceed with an energy bill--report it out, bring it to the floor, and vote on amendments in an orderly manner.

As I further indicated earlier, the majority leader has indicated that it is his intent to develop an energy bill--in his words, a ``balanced bill''--and it would be introduced by the majority leader. Of course, this excludes the process associated with the committee reporting out a bill.

Further, in the discussion that has taken place today, the issue of ANWR came up as the bone of contention. I want to address a couple points because there is a good deal of misunderstanding around this issue. There was a reference today that the accident that occurred when a bullet penetrated the pipeline earlier this week was proof that we should not rely on increasing the supply of oil that would traverse through that pipeline.

I remind my colleagues that that pipeline is about 28 years old. It has provided the Nation with 25 percent of the total crude oil produced in the United States for that period of time. That volume has dropped from 25 percent to 17 percent. The pipeline capacity was a little over 2 million barrels a day previously, in the early development of the Prudhoe Bay oil fields, that flowed through that pipeline. Today, with the decline in Prudhoe Bay, it has dropped a significant amount, to roughly 1 million barrels a day. But it still supplies this Nation with 17 percent of the total crude oil produced in this country.

Now, to suggest that this firing by a very high-powered rifle penetrated the pipeline is not quite accurate because it has been shot at numerous times. It is half-inch, high-tensile steel. It is my understanding that this particular firing--a blast of five bullets--penetrated an area where there is a valve and, as a consequence, because of pressure in the pipeline, there was a significant leak, a spillage. The question of whether there is any permanent damage done has been addressed in the cleanup. There was no movement of any oil into any water or streams in the area. The security group of Alyeska found the incident as a consequence of the notification of a drop in pressure. They went out with helicopters and not only found the leak but identified and arrested the perpetrators. You can criticize anything, but the system did work. Everything is subject to, obviously, the exposure of terrorist activity, but in this particular instance this was a fellow who was extremely drunk, bored, or he lost his mind, and he simply decided it would be fun to start firing at the pipeline.

That pipeline has been bombed; bombs have been wrapped around it. It has been wrapped with hand grenades, shot at, and it suffered exposure of numerous earthquakes over the 27 years and it continues to be one of the wonders of the world. So to suggest that somehow this bullet-piercing accident is somehow questionable relative to the integrity of that pipeline is an expression of very little knowledge--factual knowledge--on behalf of those who suggest that somehow the pipeline can't be trusted for additional flowthrough if indeed ANWR is developed.

I am going to conclude, as I promised my friend from Pennsylvania that I would be brief, with an explanation of some of the more common myths associated with the ANWR issue. I hope we can get ANWR

up before this body and vote on it up or down in conjunction with an energy bill. That is the democratic process. Clearly, that did not prevail in the Energy and Natural Resources Committee because I can only assume the votes were there to report out a bill with ANWR in it. I can only assume the votes are in this body to pass an energy bill with ANWR in it. Polling seems to indicate nearly 60 percent of the American public support opening ANWR as a significant contributor to reducing our dependence on imported oil.

Some say there is an insufficient amount of oil. Some say it is only a 6-month supply and not nearly enough to justify exploration. That is nonsense. The U.S. Geological Survey, experts who have studied the 1002 ANWR area, estimate that between 6 and 16 billion barrels of oil are economically recoverable; 10 billion barrels is equivalent to what we would import from Saudi Arabia over a 30-year period; 10 billion barrels is the equivalent of what we import from Iraq for a period of 50 years.

We are importing a million barrels a day from Iraq and enforcing the no-fly zone. We are taking the oil, putting it in our airlines, bombing some of the targets in Iraq, and have for some time. They take our money, pay the Republican Guard, develop a missile capability, and aim it at our ally, Israel.

Maybe that is a short synopsis of foreign policy, but nevertheless I think one can conclude that is the ultimate outcome.

We do not know what is in ANWR because we have never been allowed to determine through modern exploration, through seismic exploration, specifically what is available. Only Congress can authorize it.

What is the extent of the area? It is interesting because ANWR is about 19 million acres--about the size of the State of South Carolina. The proposal is to allow exploration on 1.5 million acres. The House-passed bill, which is H.R. 4, has limited that to 2,000 acres. That is the size of a small farm in the entire State of South Carolina--the wilderness, if you will, as a comparison.

Prudhoe Bay was supposed to produce 10 billion barrels. It is on its 13 millionth barrel today. It is absurd to think ANWR is only a 6-month supply of oil. That is to assume ANWR is the country's only source of oil; that there is no oil produced in Texas, or Louisiana, offshore, or no other oil is being imported into the country. The American people are wise enough to see that argument just does not hold oil, if you will.

Clearly, the potential for this country's domestic supply is ANWR, and the abundance associated with the likelihood of a major discovery is second to none identified in North America. It is almost like wondering if you have a strategic petroleum reserve in your own backyard, but if you do not know, and if you do not have the ability to develop it, you really cannot use it.

What is required in development? Very little. We need authorization by Congress. The House has done its job. The House passed a bill. H.R. 4 includes ANWR. It is a challenge to the Senate to do its job.

Some say it will take as long as 10 years before the oil is flowing and that is too long to make a difference. If the

previous President had not vetoed the budget reconciliation bill in 1995, today ANWR would be open, or if the oil was not there, it might have been a park. We could have been less dependent on foreign oil, and our energy future would look a lot more certain if, indeed, we had taken that action back in 1995, but we could not overcome a Presidential veto.

We built the Pentagon in 18 months. We built the Empire State Building in a year. Industry says if they make a discovery, they can develop and get oil online in somewhere between 18 months and 2 1/2 years, depending on our will to give them the authority within the environmental parameters to do it safely.

Some people say our energy policy is misguided; we need to focus on natural gas. We found 6 trillion cubic feet. Let's use gas. Recognize that America moves on oil. Our planes, our ships, our trains move on oil.

In response to the September 11 attack, we are preparing now for a long, sustained war. Are we going to count on unstable governments in the very part of the world where we are fighting to assure our energy security? We need to begin at home with energy solutions found within our borders, and if we make the commitment to authorize the opening of this area, I assure my colleagues it will be very symbolic. It would send a very solid message to that part of the world were we to continue to increase our dependence on imported oil.

About 67 percent comes from foreign sources, a majority of that from the Mideast. Fighting a war uses a lot of energy. Mr. President, 450,000 barrels of petroleum products were estimated to be used daily, and that was through 582,000 soldiers in the Persian Gulf war. It is estimated we are using over 500,000 barrels a day currently in this conflict.

[Page: S10423]

Some say it is America's Serengeti, its mountains; it is deserted; it is beautiful. Again, it is the size of the State of South Carolina. It is 19 million acres. Can we open it safely? Yes.

Some say we can get the energy from the National Petroleum Reserve in Alaska; that is why it was established. That is wishful thinking because actually just 15 percent of that entire coastline is open for exploration. Just 3 years ago, the Federal Government closed vast amounts of NPR to protect the birds that live in the lakes. If you look at the model and lakes over NPR, that is where bird life is. There are very few lakes associated in the ANWR area.

Finally, there is a concern of the Porcupine caribou and the Gwich'ins, but no one mentioned what is happening on the Canadian side and involvement of the Gwich'ins who are participants in putting up land for lease.

There was an extraordinary article in the Vancouver Sun newspaper indicating the Gwich'ins are benefiting greatly from oil and gas exploration because Canada expanded its oil and gas leasing program to include testing exploratory wells, et cetera.

The bottom line is there seems to be a great fear suddenly to take up an energy bill, with no particular explanation, particularly when the administration has encouraged Congress to take it up, particularly when the House has done its job, and now we are advised by the majority leader that the committee of jurisdiction, the Energy and Natural Resources Committee, is going to suspend any further markup on energy legislation for ``this session''--this session.

I have a press release that states that instead the chairman will propose comprehensive and balanced energy legislation. The chairman will. It does not say with the participation of the committee or the minority or the Republicans. It says the chairman outside the parameters of the committee.

It further says ``the comprehensive and balanced legislation that can be added''--it does not say ``will be added;'' it says ``can be added''--``by the majority leader to the Senate calendar for,'' it says, ``potential action.'' It does not say ``action.''

Mr. President, I ask unanimous consent that the press release be printed in the RECORD.

There being no objection, the material was ordered to be printed in the RECORD, as follows:

Energy Committee Suspends Mark-Ups; Will Propose Comprehensive and Balanced Energy Legislation to Majority Leader

At the request of Senate Majority Leader Tom Daschle, Senate Energy & Natural Resources Committee Chairman Jeff Bingaman today suspended any further mark-up of energy legislation for this session of Congress. Instead, the Chairman will propose comprehensive and balanced energy legislation that can be added by the Majority Leader to the Senate Calendar for potential action prior to adjournment.

Noted Bingaman, It has become increasingly clear to the Majority Leader and to me that much of what we are doing in our committee is starting to encroach on the jurisdictions of many other committees. Additionally, with the few weeks remaining in this session, it is now obvious to all how difficult it is going to be for these various committees to finish their work on energy-related provisions.

Finally, and perhaps most importantly, Bingaman said, the Senate's leadership sincerely wants to avoid quarrelsome, divisive votes in committee. At a time when Americans all over the world are pulling together with a sense of oneness and purpose, Congress has an obligation at the moment to avoid those contentious issues that divide, rather than unite, us.

Bingaman will continue to consult and build consensus with members of his committee, with other committee chairs and with other Senators as he finalizes a proposal to present to the Majority Leader.

Mr. MURKOWSKI. I encourage again the majority leader to reflect on this action, give us the assurance he will take it up during this session and allow sufficient time for Members to provide for amendments, provide us with an opportunity to have an up-or-down vote on contentious issues, and that we meet our obligation as the Senate, as the House of Representatives has done, in addressing what is in the national security interests of our Nation, and that is the passage of the comprehensive energy bill.

I thank my colleague from Pennsylvania for allowing me this extra opportunity to speak.

The PRESIDING OFFICER. The Senator from Georgia.

Mr. MILLER. I ask unanimous consent to speak as in morning business for up to 5 minutes.

The PRESIDING OFFICER. Without objection, it is so ordered.

END

Daschle Stops Panel's Consideration of Energy Bill

Measure, Headed for Passage, Would Have Allowed Oil Drilling in Arctic National Wildlife Refuge

By Eric Pianin and Peter Behr
Washington Post Staff Writers
Thursday, October 11, 2001; Page A04

Senate Majority Leader Thomas A. Daschle (D-S.D.) yesterday abruptly halted further committee consideration of major energy legislation after Democrats concluded there were probably enough votes on the panel to approve the Bush administration's plan for drilling in Alaska's Arctic National Wildlife Refuge.

Two Democratic members of the Energy and Natural Resources Committee -- Sens. Daniel K. Akaka (Hawaii) and Mary Landrieu (La.) -- said they would vote with the Republican minority in favor of exploratory oil and gas drilling along the coastal plain of the Alaskan refuge, provided they agreed with other major sections of the energy package, according to their aides.

"Several members of the other side don't want a vote on ANWR because they know they would lose," Sen. Frank H. Murkowski (R-Alaska), a chief proponent of the drilling plan, angrily told reporters. "They didn't have the votes in committee and we did."

Senate Democratic and energy industry sources confirmed that Murkowski had enough votes in committee to approve the Alaska drilling proposal. An aide to Daschle said that while he was unaware of a hard count, the issue had become "a bit of a wild card" for the Democrats.

As majority leader, Daschle has authority to bring up a major energy bill of his choosing, and some senior Democrats are urging him to do so if he can work out an agreement with the GOP and the administration to set aside the question of drilling in the Alaskan refuge.

The House in early August approved drilling in the pristine 19 million-acre Arctic refuge along with other major portions of President Bush's plan to stimulate energy production, including $33.5 billion in tax breaks and other incentives for the power industry aimed at increasing domestic production.

Environmentalists and their Democratic allies -- stunned by the strong 240 to 189 House vote and the effective lobbying by the Teamsters and other labor groups that favor drilling -- assumed that they could derail the drilling plan in the Senate or block it with a filibuster.

But with the labor groups continuing to press for approval of the drilling plan and Akaka and Landrieu signaling their likely support, Democratic leaders decided not to risk a vote. Instead, Daschle instructed Sen. Jeff Bingaman (D-N.M.), chairman of the committee, to suspend any further markup of energy legislation and provide him with a set of energy proposals that he could place on the calendar for "potential action" before adjournment.

Some Democrats said that with so many other pressing issues and a looming deadline for adjournment, that it was unlikely the Senate would turn to an energy package until early next year. However, Bingaman said yesterday that Daschle still hopes for action on energy legislation before adjournment, after Congress completes work on emergency legislation to address the continued threat of terrorist attacks and recession and the 13 spending bills for the fiscal year that begins Oct. 1.

Bingaman said that, after weeks of deliberation within his committee, it became apparent that many of

the issues under consideration -- from electricity restructuring to automobile and air conditioning efficiency standards -- fall under the jurisdiction of other committees that need to be consulted.

"He [Daschle] wants the Senate to be in a position to move to consideration of an energy bill in a timely fashion and it was his view that this process of putting a bill together -- hopefully on a consensus basis, involving input from Democrats and Republicans -- was the best way to do that," Bingaman said.

But Murkowski and fellow Republicans Larry E. Craig (Idaho) and Craig Thomas (Wyo.), yesterday blasted Daschle's action, saying that it would almost certainly postpone action on an energy package during a time of war, when the United States should be attempting to reduce its dependence on oil from the Middle East.

Craig said that by ordering the Energy and Natural Resources Committee to "cease and desist," Daschle is blocking "a national energy policy for this country, which is now a national security issue."

Daschle spokesman Doug Hattaway said the majority leader "thinks it [the energy package] is an important piece of legislation and ought to be considered as soon as possible . . . but he's made no commitment on when it would go to the floor."

Daschle's maneuver allows him to attach other important and highly controversial issues to an energy bill that are not within the jurisdiction of Bingaman's energy committee.

If he chooses, Daschle could seek a Senate vote on a proposal he made last year to greatly increase the use of ethanol -- a grain byproduct -- as a pollution control additive in gasoline. Strongly backed by corn growers in Daschle's state, an ethanol promotion measure could trigger a divisive Senate debate over formulas for blending gasoline, which vary greatly from region to region.

The nation's energy agenda had occupied center stage in the first months of the Bush administration. Since then, it has lost steam as California's electricity crisis eased, energy prices dropped around the nation, and the administration focused on the terrorism crisis.

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governmentwide board Bush plans to set up shortly that will coordinate the protection of critical information systems.

The two appointments came one day after Bush formally named former Pennsylvania Gov. Tom Ridge as the head of the new Office of Homeland Security, which will coordinate the executive branch's efforts to deal with terrorist threats within the United States.

The White House said Downing and Clarke will report to both Ridge and National Security Adviser Condoleezza Rice. Rice said she and Ridge plan to work closely together to make sure U.S. security in the face of terrorist threats is "seamless."

"We will make sure that what we are doing abroad to protect and defend American national security is closely coordinated and matched with what we are doing to protect the security of Americans at home," Rice said.

Two-Prong Effort Described. Rice and Ridge described the appointments as part of a two-prong effort being undertaken in the wake of the terrorist assaults last month on New York and Washington. The reorganization of the government underway, Rice said, puts an emphasis both on fighting terrorism on the global level and domestically.

In his role as national director for combating terrorism, Downing will be the president's principal advisor on all matters related to combating global terrorism, including efforts to detect, disrupt, and destroy global terrorist organizations, the White House said.

The White House said Downing has ample experience in combating terrorism, crisis management, training large and small organizations, and more. During his 34-year career in the Army, it said, Downing served in a variety of command assignments in infantry, armored, special operations, and joint units culminating in his appointment as the commander in chief of the U.S. Special Operations Command. After his retirement, he was appointed by the secretary of Defense to assess the 1996 terrorist attack on the U.S. base at Khobar Towers in Saudi Arabia and to make recommendations on how to protect U.S. facilities worldwide from terrorist attack. More recently, Downing served on the National Commission on Terrorism.

Downing said his job will be difficult and did not predict any early conclusion to the administration's war against terrorism.

"[L]et's not make any bones about it: this is going to be an extremely difficult job," Downing said. "It's a tough foe, it's a determined foe. And as events have shown us, it's a very, very smart foe and a crafty foe."

Cyberspace Terrorism Feared. Ridge said the administration remains particularly concerned about protecting the nation's information technology.

"It pervades everything from a shipment of goods, to communications, to emergency services, and the delivery of water and electricity to our homes," Ridge said. "All of these aspects of our life depend on a complex network of critical infrastructure information systems. Protecting this infrastructure is critically important."

Ridge said the challenge is both to prevent disruptions and, when they occur, make them infrequent, short, and manageable. Besides being a technical challenge, he said, it is a legal challenge, since the effort raises both privacy and civil liberties issues.

Ridge also said there is a political challenge involved as the government must work in partnership with the private sector, which owns and operates most of the nation's infrastructure.

Ridge said Clarke is one of the nation's leading experts on cyber security, having been appointed the first national coordinator for security, infrastructure protection, and counter-terrorism in May of 1998. He also has served as deputy assistant secretary of State for intelligence in the Reagan administration and as assistant secretary of State for political military affairs in the first Bush administration.

Besides being Bush's principal advisor on cyber security, Clarke will serve as chairman of a new board that will be charged with coordinating the protection of infrastructure systems, Ridge said. The president, he added, is expected to sign an executive order soon that will formally establish the governmentwide board.

BY NANCY OCHIANOVICH

Energy

[redacted]

Sen. Jeff Bingaman (D-N.M.), chairman of the Senate Energy and Natural Resources Committee, announced Oct. 9 that he intends to abandon all committee efforts to mark up a comprehensive energy bill before the end of this session.

The move is designed to avoid contentious votes which Republicans say include issues such as drilling in the Alaskan National Wildlife Refuge.

But Republicans were incensed. "This action by the Democratic majority has taken the nation's energy security and made it a partisan issue locking out Republicans and the entire committee process," Sen. Frank H. Murkowski (R-Alaska) said. Murkowski is the ranking member of the Senate Energy and Natural Resources Committee.

The decision to avoid "divisive votes" came at the request of Senate Majority Leader Tom Daschle (D-S.D.), Bingaman said in a prepared statement.

"The Senate's leadership sincerely wants to avoid quarrelsome, divisive votes in committee," Bingaman said in a prepared statement. "At a time when Americans all over the world are pulling together with a sense of oneness and purpose, Congress has an obligation at the moment to avoid those contentious issues that divide, rather than unite, us."

In place of a committee markup, Bingaman will deliver a legislative package to Daschle. The majority leader plans to add the legislation to the Senate calendar for a vote prior to Congress adjourning, Bingaman said.

Prior to Bingaman's announcement Daschle told reporters that he hopes there will be time this session to bring the energy bill to the Senate floor for a vote.

"A lot of my colleagues are hoping we will be able to address [an energy bill]," Daschle said.

Democrats Dodge ANWR Vote. The move comes on the heels of Republican pressure to move ahead with an energy bill and to vote on an amendment to allow drilling in ANWR.

DRAFT AGENDA

Alaska Highway Natural Gas Policy Council

October 31, 2001, 9:00 a.m. to 4:30 p.m.

Sheraton Anchorage Hotel

9:00 – 9:10 a.m.	Introductory Remarks Council Co-Chairs
9:10 – 10:00 a.m.	Consideration of Ownership Committee recommendations
10:00 – 10:50 a.m.	Consideration of Federal Committee recommendations
10:50 – 11:10 a.m.	Break
11:10 a.m. – 12:00 noon	Consideration of Alaska Hire Committee recommendations
12:00 – 1:15 p.m.	Lunch
12:45 p.m.	Keynote Remarks Governor Tony Knowles
1:15 – 2:15 p.m.	Consideration of Access Committee recommendations
2:15 – 2:30 p.m.	Break
2:30 – 3:30 p.m.	Consideration of Environmental Committee recommendations
3:30 – 4:30 p.m.	Closing Remarks/Meeting Wrap-Up Council Co-Chairs

Subject: Draft Subcommittee Reports Attached
Date: Sun, 28 Oct 2001 18:15:11 -0900
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Attached please find four draft Subcommittee Reports for the Gas Policy Council. The Council will meet at 9 am Wednesday, October 31 at the Sheraton to vote on the recommendations contained in each of the attached reports.

The Environmental Considerations Subcommittee is still working to finalize its recommendations. We will forward you their report as you as it is available.

If you have any trouble opening these attachments or would like copies

DRAFT

Committee Report

Federal/International Action Committee

Charlie Cole, Chair

Introduction

Members of the Gas Policy Council were extensively involved in decisions on state policy and in the development of proposed legislative changes. A substantial product of the Federal/International Action Committee were recommendations for changes to federal law to address key concerns of the state of Alaska in the development of a natural gas pipeline.

The committee supports modifications to modernize ANGTA and believes such modifications would be beneficial to an Alaska gasline project. The committee endorsed ten key policy goals that should be included in any new gasline legislation.

The ten policy goals developed to guide drafting of the legislation were debated by the full Council and ratified in concept by a majority of its members on September 25, 2001. Several changes were made as a result of points raised by Council members during the September 25 debate.

If Congress moved forward with new legislation as suggested by the producers, a principal concern of the Council was that Congress should take steps early to reaffirm the southern, or Alaska Highway, route as the sanctioned route for a natural gas pipeline, as a previous Congress did in 1977 when it ratified the President's choice of the southern route under the Alaska Natural Gas Transportation Act. Such a step would focus the attention of industry and federal agencies on regulatory and permit approvals for a project along this route.

This committee also notes that a southern route provides several advantages over other alternatives. Among these is use of the pipeline corridor for other purposes, including the possibility of constructing a railroad or other utilities over time. In addition, a southern route could facilitate access to highly mineralized areas which are located in close proximity.

A second concern of the Council was the probability that with a new initiative in Congress, an Alaska gas pipeline would be subject to Federal Energy Regulatory Commission jurisdiction on issues important to Alaska without a defined role for the state with the FERC. Such issues would include tariffs on intra-state shipment of gas, and access to and from a pipeline. The proposal for a Joint Board that would give the Regulatory Commission of Alaska joint jurisdiction with FERC on issues affecting Alaska grew out of this concern.

Other concerns of the Council involved provisions to encourage hiring of residents of Alaska for a gas pipeline project, and the hiring of Native Alaskans.

It was recognized by the Council that the pipeline project will be substantial and that, for all practical purposes, qualified Alaskan workers wishing to work on the project will be employed. Still, an explicit encouragement to hire locally will be a strong inducement for companies and unions to train Alaskans for pipeline-related construction and operating jobs. The skills developed in the Alaskan workforce as a result of training and employment will thus be a lasting legacy of the project.

The Council also considered the importance of pipeline access and the need for future open seasons to facilitate pipeline access for new discoveries. Failure to provide for additional capacity either at startup or through future open seasons could create a "monopoly" on pipeline capacity, discouraging exploration by non-owners. Any new gasline legislation must address this issue to protect the interests of the state of Alaska.

Other policy points guiding development of proposed legislation are detailed later in this report.

The committee recognizes the Governor's strong advocacy of the 10 Principles, as reflected in his recent testimony before the Senate Committee on Energy and Natural Resources and in other forums. It would appear that the State's policy position is well understood by decision makers in Congress and the Federal Executive Branch.

With this in mind, the committee believes that it would be useful for the State administration to continue its efforts with the commercial parties to develop a market driven solution to transport Alaska natural gas to market via the Alaska Highway route.

Close coordination and communication between the State, the North Slope producers and the pipeline companies could facilitate the establishment of a consortium of companies with the financial capability to build the pipeline.

In our opinion, current discussions among the parties concerning economic feasibility and reestablishment of the previous pipeline partnership underscore the need for such coordination at this time.

Background on ANGTA

Congress enacted the Alaska Natural Gas Transportation Act (ANGTA) in October 1976, after finding that the national interest called for the expeditious construction of a transportation system to bring Alaska natural gas to markets in the lower 48 states. The

primary goal of ANGTA was to "provide the means for making a sound decision as to the selection of a transportation system . . . by providing for participation of the President and Congress in the selection process, and . . . to expedite its construction."[1]

To achieve that goal, the Federal Power Commission (the precursor to the Federal Energy Regulatory Commission ("FERC")), held hearings and prepared a "Recommendation to the President," which recommended two possible overland routes through Alaska and Canada. The President then selected the southern route, the Alaska Natural Gas Transportation System (ANGTS), as the preferred alternative. Congress approved the President's selection by a joint resolution in November 1977.

ANGTA establishes the framework under which federal agencies (including the FERC) are to review and approve the ANGTS project. ANGTA supplements, but does not supersede, the Natural Gas Act – which is the law that normally governs approval of natural gas pipelines, and requires a certificate of public convenience and necessity before interstate natural gas pipelines are built.

However, because ANGTA was designed to expedite construction of an Alaska gas pipeline, it contains numerous provisions that speed up administrative and judicial review. For example, ANGTA directs that any applications under it shall take precedence over similar applications and shall be expedited by federal agencies.[2] ANGTA also provides that a Federal Inspector be appointed to coordinate all federal activities and enforce federal requirements.[3]

In addition, ANGTA contains provisions dealing specifically with access to facilities and in-state access to gas. ANGTA provides that there shall be no discrimination against any shippers based on the degree of ownership in the system. It also provides that the State of Alaska is authorized to ship its royalty gas on the system and withdraw its gas for use within Alaska.[4]

Finally, ANGTA limits judicial review of any agency action to issues of whether the agency violated constitutional rights or statutory authority – effectively limiting the scope of environmental challenges to a project constructed under ANGTA.[5]

Because no project has been constructed under ANGTA since its enactment 25 years ago, there may be outstanding issues regarding its current application. For example, the

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[1] 15 U.S.C. § 719a.
[2] 15 U.S.C. § 719g.
[3] This provision was repealed in 1992. Pub. L. 102-486, Title XXX § 3012(a), Oct. 24, 1992, 106 Stat. 3128.
[4] 15 U.S.C. § 719k.
[5] 15 U.S.C. § 719h.

creation of legislatively designated areas—such as parks or wildlife refuges—may require re-routing portions of the project. This raises the question whether the project approved by the President has been altered so substantially as to render the findings in ANGTA ineffective. In addition, a competing project may be proposed under the Natural Gas Act, raising the issue of whether the preferential treatment required under ANGTA has already been provided, or whether an ANGTA project must be constructed before any other project designed to bring Alaska gas to the lower 48 states can be approved.

Summary of the "Alaska Natural Gas Pipeline Act of 2001"

The "Alaska Natural Gas Pipeline Act of 2001," set forth by the Alaska Gas Producers Pipeline Team, provides a streamlined administrative process and limited judicial review for non-ANGTA gasline projects. The legislation is designed to eliminate outstanding legal issues regarding whether non-ANGTA gasline projects may proceed absent the repeal of ANGTA.

Section 2 of the bill, "Congressional Findings," states that it is in the national interest to provide "as much regulatory certainty and expedition as practicable" for approval of one or more pipeline systems from Alaska to the lower 48.

Section 3 of the bill, "Congressional Purpose," states that the purpose of the bill is to expedite federal decision making, create an Office of the Federal Pipeline Director to coordinate federal agency decisions, and expedite and limit judicial review concerning both the Act and the approval process for any Alaska gasline project.

The bill defines "Alaska Facilities Gas Project" to mean any natural gas pipeline system that carries Alaska gas to the lower 48. It does not specify a preferred route.

Section 5 of the bill amends the Natural Gas Act to set out an expedited approval process for an Alaska gasline. It directs the Federal Energy Regulatory Commission ("FERC") to issue approval within 18 months of an application if: there is an agreement to ship with a party that controls Alaska natural gas; rates can be established according to FERC's usual procedures; and if there is compliance with all environmental laws.

The bill states that the lead agency for preparing an EIS shall be the FERC, and that the environmental impact statement ("EIS") process shall be expedited and the final EIS issued within 18 months after an application is filed.

Section 7 of the bill establishes the Office of the Federal Pipeline Director. This office appears to have a function analogous to the Office of the Federal Inspector, created under ANGTA. The Federal Pipeline Director will coordinate all federal activities related to the pipeline project. It will be a "one window point" for filing and issuing all necessary

permits and is responsible for coordinating and expeditiously completing all environmental reviews and studies.

The bill directs federal agencies to coordinate and expedite review of the gasline project and gives the Federal Pipeline Director the authority to remove discretionary requirements from federal permits if they would impair or prevent the expeditious construction of the pipeline.

Section 9 of the bill limits judicial review to claims challenging the Act itself, constitutional claims, or claims that an agency is acting outside of its jurisdiction. Lawsuits must be brought within a shortened time frame, with jurisdiction in the U.S. Court of Appeals for the District of Columbia.

Section 10 provides that, if any provisions of the Act are invalidated, the remainder of the provisions will be unaffected.

Background on Canadian relations

First Nations

The Kaska First Nations located in Northern British Columbia and the Yukon continue to negotiate land claims and self-government agreements with the Government of Canada and the Province of British Columbia. While these negotiations are expected to continue for the foreseeable future, speculation is that when the time is right, the Kaska will be open to a side agreement on any proposed pipeline running through their territory.

The eight First Nations who have land claims along the proposed route of the Mackenzie Valley pipeline have been negotiating with producers since late spring of 2001. Early in October of 2001, seven of the eight groups came to an agreement on ownership sharing of any pipeline built through their territories. This agreement would grant 30% ownership to the First Nations Bands. The eighth, the De Cho, refuse to sign the agreement. While the Minister of Indian Affairs and Northern Development has been quoted as saying that one Band cannot hold a veto over any project, the De Cho believe that they have the right to refuse construction on lands they claim.

Position of the Government of Canada on Arctic Gas Production and Transportation

The Government of Canada has affirmed that in relation to this project, all departments and agencies will maintain route and project neutrality. In the spring of 2001, the Prime Minister set up a Cabinet reference group to study the current state of Canada's energy policy. The main issue of study was whether to express a preference for one route over another. A number of Cabinet Ministers expressed support for either the over-the-top route or a two-pipeline route with the construction of the Mackenzie Valley line happening first. After careful consideration of all available information and a careful review of the regulatory implications of each option, the Cabinet reference group

recommended to the Prime Minister that the original position of route and project neutrality be maintained.

Provincial and Territorial Positions

Of the four non-federal jurisdictions involved in the issue, only the Yukon Territory is firmly supporting the Alaska Highway route. While they have not been overly aggressive in the past, they intend to become more aggressive in promoting the route with the Canadian Federal Government. The Yukon Government has commissioned an economic study of the benefits to Canada of constructing and operating the Alaska Highway route and it is expected that this study will be released to the public in January of 2002.

The Northwest Territories is aggressively promoting the Mackenzie Valley line either in conjunction with an over-the-top segment or as a stand-alone line. Assuming the latter is chosen by producers, the Northwest Territories is demanding that this line be built before an Alaska Highway gasline. They are very active with the Federal Government asking for financial incentives to ensure the line's construction.

The other two jurisdictions involved, British Columbia and Alberta, have remained route and project neutral. Premier Klein of Alberta has said that regardless of what line is built, he will not allow a "bullet line" to cross his province. He demands that Albertans share in the long term economic prosperity created by a line to the lower United States. Principally, he is referring to gas liquids and would like to see the petrochemical industry in his province benefit from them.

While it would seem logical for the Government of British Columbia to be supportive of the Alaska Highway route, this government has only been in power since June 2001 and this issue has yet to be critically examined by the Premier and his Cabinet.

Recommendations

The committee endorsed ten key policy goals that should be included in any new federal gasline legislation. The 10 principles and corresponding legislative provisions are outlined below.

Key principles

1. Find that the Alaska Highway natural gas pipeline is in the national interest.
2. Mandate the already permitted Alaska Highway route as the preferred route.
3. Provide opportunities for new pipeline participants, such as existing producers, pipeline companies, and major Alaska companies.

Corresponding Legislative Provisions

- The 1976 Alaska Natural Gas Transportation Act (ANGTA) that established a process selecting the ANGTS project following the Trans-Alaska Pipeline and the Alaska

Highway through Canada to the lower 48 should be the framework for any new gasline legislation.

- The legislation should provide for updating and modernizing the process provided in ANGTA for the expeditious environmental review and approval of a pipeline application for the Alaska Highway route.
- A finding that an Alaska Highway route would make an important long-term contribution to the nation's energy supplies and independence.
- A finding that an Alaska Highway route would have less potential environmental impacts and related delays in construction.

Key principles

4. Provide a mechanism for Alaska communities and businesses to obtain access to natural gas from the pipeline.

Corresponding Legislative Provisions

- FERC should require each project sponsor to demonstrate how the sponsor plans to meet reasonable projections of in-state local consumption needs, including the needs of Fairbanks, Cook Inlet, and rural Alaska. In addition, the sponsor should allow for possible future construction of a pipeline to tidewater for the export of LNG.
- The Regulatory Commission of Alaska should have concurrent jurisdiction with FERC to set just and reasonable rates for the shipment of natural gas over the Alaska section of the gasline for in-state users.
- The Regulatory Commission of Alaska should have exclusive jurisdiction to set just and reasonable rates for any lateral pipeline connected to the Alaska section of the gasline that serves in-state users.

Key principles

5. Provide access to the pipeline for new natural gas discoveries that will keep Alaska's oil and gas industry healthy through new leasing, exploration and production.

Corresponding Legislative Provisions

- FERC should require each applicant to make reasonable plans and procedures, including additional open seasons if necessary, for the expansion of the Alaska section of the gasline as new fields of natural gas are developed on the North Slope and throughout Alaska.
- FERC should be authorized to order expansions of the gasline in the future under reasonable, non-discriminatory terms.

Key principles

6. Provide for Alaska hire and Alaska Native hire.
7. Provide for the use of Alaska businesses.

Corresponding Legislative Provisions

- To the extent allowed by law, Alaska residents and contractors should be employed when they are available and qualified. In turn, contractors would be encouraged to employ and train Alaska residents.
- Recruitment should be accomplished primarily by advertising in-state and using Alaska's job service organizations to notify the Alaskan public.
- The project sponsors must, whenever feasible, enter into construction contracts with Alaska firms and fabricate modules in Alaska.
- The gasline sponsors should be required to enter into an agreement to provide for pre-employment recruitment, on-the-job training, and employment of Alaska Natives.

Key principles

8. Provide for a project labor agreement for the construction and maintenance of the pipeline, and for worker training.

Corresponding Legislative Provisions

- The project labor agreement should require all contractors and employees to agree to a total ban on strikes, lock-outs and other disruptive activities for the life of the agreement.
- The agreement should be designed to ensure a steady supply of skilled labor and a contractually binding means of resolving worker grievances.

Key principles

9. Provide a priority for the use of American and Canadian steel.

Corresponding Legislative Provisions

- Only steel manufactured or produced in the US or Canada should be used in the construction of the Alaska section of the gasline unless its use is inconsistent with the public interest or the cost is unreasonable. Factors to be considered in evaluating the public interest should include quality, availability and delivery times.

Key principles

10. Provide for economic incentives to give investors in ANGTS additional levels of confidence.

Corresponding Legislative Provisions

- Accelerated depreciation on gasline investments.
- An investment tax credit for an approved ANGTS project.
- A tax credit for producing gas from the Alaska North Slope tied to a price floor.

DRAFT

Committee Report

State Pipeline Ownership and Tax Structure

Bill Corbus, Chair

Recommendation:
The Committee believes the pipeline is economically feasible for certain investors and should be undertaken with private financing. We recommend against direct state investment unless there is clear evidence of economic benefits to Alaska that cannot be achieved through other regulatory or political mechanisms.

Recommendation:
The Committee encourages exploration of creative financial structures to facilitate all or part of a gas pipeline and/or in-state gas infrastructure, provided such entities finance their activities through private markets.

Recommendation:
The Committee recognizes that state tax policy is one of several tools that could play a role in influencing pipeline development, but reserves a decision. It is premature to decide how to use this tool until there is more definition of a project and the nature of its ownership.

Conclusions:
* When the Committee began its work early in 2001, there appeared to be certain problems that could be resolved by partial state ownership in a gas pipeline, and that it could be an important advantage for Alaska. However, through the process of gathering information and holding meetings, the Committee has determined that most if not all of these could be resolved through other means, other tools the state has at its disposal. For example, access to and from a pipeline can be facilitated through the state Regulatory Commission of Alaska working with the Federal Energy Regulatory Commission, and through stipulations in a state right-of-way lease across state lands.

* The Committee believes a natural gas pipeline from Alaska would be good investment, but there are other, equally good investment opportunities for public funds that entail less risk. The state has a policy of diversifying investment of its assets (the Permanent Fund is an example) to reduce risk.

* From information gathered during hearings, the Committee has concluded that, absent majority or total ownership of a natural gas pipeline, an ownership interest gives the state no right to capacity in the pipeline. Capacity in a contract carrier pipeline is obtained through the nomination process during an "open season."

* The Committee is not persuaded that partial ownership of the pipeline raises any conflict of interests for the state (i.e. a state "ownership" interest vs. a state responsibility to regulate the pipeline) that cannot be resolved.

* The Committee investigated alternative sources of financing, including the Permanent Fund, Constitutional Budget Reserve and the ability of various public authorities to issue revenue bonds. The Committee believes that private sector companies can raise needed funds based on adequate coverage and financing reserves. State participation would not enhance the acquisition of funds, would not necessarily guarantee lower financing costs and might unduly interfere with a straightforward private sector funding. The State's participation would include a vote on a tariff but its interest would not be proportionately large and it would not guarantee a desired outcome.

* Absent a compelling public interest for partial state ownership, ownership of the pipeline is best left to private industry, and to firms which are experienced in oil and gas and the pipeline business.

* The Committee suggests that Alaskan-owned businesses, such as Alaska Native corporations, have the opportunity to invest in a natural gas pipeline project.

* Regarding alternative financing mechanisms, the Committee has been told by the producers' group that an investment in a gas pipeline might not meet the rate-of-return criteria for the producing companies. If so, alternative financing mechanisms, such as through a public authority, might facilitate others, such as pipeline transmission companies, becoming involved. A public authority may have advantages in terms of exemption from federal income tax, or jurisdiction by the Federal Energy Regulatory Commission.

* Regarding tax policy, the producers are seeking simplification and clarity in natural gas tax and royalty administration.

* The Gas Policy Council itself has endorsed the Governor's proposals for federal tax incentives, such as accelerated depreciation, an investment tax credit and a gas price volatility protection mechanism, a tax credit that becomes effective if prices fall below a certain point. The Committee reaffirms this endorsement.

* The Committee feels that if a viable proposal for a pipeline is put forward and the producers do not respond in a reasonable period of time, the state should use tools that it has available to facilitate the project moving forward.

* House Bill 393, enacted by the Legislature to facilitate construction of a liquefied natural gas project (and since lapsed) contained a mechanism for a "contract" between the state and a sponsor of a gas pipeline project that would encourage stability in taxes on a gas project. While there are legal limits to the Legislature's ability to guarantee future tax policy, such a contract would carry an important moral commitment, and would be worthy of consideration for an Alaska Highway gas pipeline.

DRAFT
Committee Report
Alaska Hire/Buy/Build Subcommittee
Mike Navarre, Chair

Recommendation:
The Committee believes that Alaska hire language, similar to language from the BP/Arco Merger "Charter Commitment," should be sought for the Alaska Highway Natural Gas Pipeline and facilities. *(Note: charter language is attached)*. It should be specifically stated that the quarterly report to the Department of Labor should include all contractors and subcontractors of the company or sponsor.

Recommendation:
The Committee believes additional funding should be made available for vocational education training and should be coordinated with existing workforce training efforts now underway. Additionally, efforts should be increased to notify interested Alaskans of training opportunities available.

Recommendation:
The Committee believes every effort should be made to ensure that needed gas production facilities are constructed at sites in Alaska.

Recommendation:
The committee recommends the state's Department of Community and Economic Development undertake a study to determine the socio-economic impacts of the gas pipeline along the Alaska Highway route. The Department has already begun implementation of this recommendation. A draft "scope of work" for this study is attached.

Conclusions and narrative:
The committee held several hearings regarding the constitutionality of local hire laws. The record in Alaska on local hire litigation is not encouraging. We believe it will be difficult to construct local hire legislation that will withstand challenges under the U.S. and Alaska Constitutions (equal protection & privileges and immunities clauses). Additionally, a successful Alaska hire provision is complicated by the national and international scope of the project. Voluntary, cooperative efforts with industry seem to hold the most promise and should be pursued.

The number of jobs will be significant and will exceed the available capacity of Alaskan workers. The committee heard testimony that there is already a crisis situation being created because of the aging workforce in the oil industry, <u>without</u> factoring in the effect of a large-scale project like the gasline. There are

coordinated efforts already underway, by industry, unions, native and tribal organizations, the Denali Commission, the University of Alaska and state agencies to address the training of Alaskan workers, and those efforts will require additional funding. The Alaska Human Resources Investment Council has developed a white paper that details a comprehensive approach to workforce training. It is attached as part of this report.

In addition to assuring labor stability, a project labor agreement will facilitate the further ramping up of union training programs, bringing more Alaskans into apprenticeship and skill upgrade programs. An ancillary benefit of the PLA is the legality of geographic preference provisions of collective bargaining agreements.

Committee members heard testimony from rural residents along the pipeline route expressing interest in job opportunities. We believe that issue is best addressed through notification, to interested Alaskans, of available training and through registering of interested workers and their skills. Construction training in rural Alaska has increased to an unprecedented level in the past two years through initiatives such as the Alaska Works Partnership, the Tanana Chiefs/Laborers/Operators Cooperative Agreement, and the Denali Training Fund and other efforts funded by the Denali Commission. Continued support of these initiatives, which have resulted in training and employment of hundreds of rural Alaskans in construction, is essential if residents of communities along the pipeline and in areas of the state suffering economic dislocation due to fisheries problems, are to share in the economic benefits of the project. The Department of Community and Economic Development is already working with Native non-profits to create accurate job banks, focusing on rural areas and villages.

The committee also obtained information regarding module related jobs for gas treatment facilities and compressors. The opportunity is tremendous and construction of modules, at Alaskan sites, should be vigorously pursued. It is estimated that the module related jobs and opportunities will be bigger than the Alpine, Northstar, Badami and MIX projects combined.

ALASKA HIRE COMMITMENT LANGUAGE
(from BP / ARCO merger charter)

Alaska Hire Program

- Within constraints imposed by law, extend existing voluntary program to employ Alaska qualified residents and contractors.
- Advertise available positions locally and use Alaskan job service organizations to notify the Alaskan public of employment opportunities.
- Use best efforts to contract with Alaskan firms and fabricate modules in Alaska where feasible, taking into account commercial, health and safety and environmental conditions and requirements to ensure maintenance of the companies' operational standards.
  (use specified criteria in determining feasibility).
- Encourage contractors to employ and train Alaska residents to extent permitted by law.

Reporting

- Submit to Director, division of Oil and Gas an annual report detailing the specific measures taken/planned by companies and their contractors/sub-contractors in support of Alaska Hire Program above.
- Submit a quarterly report to the Department of Labor regarding employment of Alaska residents.

Department of Community and Economic Development
Alaska Gas Pipeline Socio-Economic Impact Study
Scope of Work (DRAFT).

The Department of Community and Economic Development is currently undertaking a study to determine the socio & economic impact of the gas pipeline along the Alaska Highway route. There are currently two segments of the report. In order for the State of Alaska to anticipate future needs arising from the gas pipeline project, it will be necessary to look at both the positive and negative impacts associated with the construction and the operation.

Segment 1

The first segment is an analysis of the impacts to state departments (specifically DCED, DHSS, DNR, DOL, DPS, DOE). The Department is currently investigating this section internally. After completing a preliminary analysis of potential impacts to state agencies, the report will be disseminated amongst the agencies so that the departments can tailor more specific questions that will need to be addressed.

Segment 2

The second segment is the potential economic benefits the gas pipeline would have for the state of Alaska and perhaps in more detail the communities along the proposed Alaska Highway route. An independent third party contractor will investigate this segment.

Identify potential economic opportunities created by the gas pipeline along the highway route during construction and also during the operational phase. For the construction phase, the study would examine past pipeline projects to see which sectors benefited from the construction activities as well as what types of business developed in the region during the construction phase.

The study would also include an analysis of what types of businesses might expand or relocate to Alaska as a result of accessibility to large supply of natural gas. These projects might include a petro chemical facility, an increase in mining activity, and transportation infrastructure. Other benefits that could be examined include the potential for cheaper utility to rural areas as well as an increase to the local tax base for communities along the pipeline.

Once the scope of work can be finalized, an RFP will be created based on the finalized scope of work.

DRAFT

DRAFT
Recommendations and Conclusions
Access for In-State Gas Use and Future Opportunities
Ken Thompson, Chair

Purpose: The Access for In-state Gas Use and Future Opportunities Committee will address key issues and make recommendations on state policies to enable fair and transparent pipeline access for in-state gas use and for the creation of a broader natural gas business within Alaska upon commercialization of North Slope gas.

Goal #1: Assess current supply/demand for in-state natural gas use and assess potential demand for expansion of current use as well as conceptual new uses.

Recommendation:
A long-term clean energy plan and vision needs to be developed for Alaska, providing for substantially increased use of natural gas for residential and industrial use and for power generation.

Recommendation:
The State should take a long-term, broad and strategic view of its entire natural gas resources. This should include areas on the North Slope, including non-producing areas, in interior basins and in south Alaska. There is a significant potential gas resource base in Alaska much larger than the 35 TCF proven natural gas reserves in existing fields on the North Slope.

Recommendation:
The State of Alaska should undertake more intensive, updated geologic and geophysical studies of the natural gas potential of current nonproducing areas, including Interior and Southcentral Alaska basins. This should include a more thorough assessment of basin geology and natural gas generation and migration utilizing the most modern technology tools, as well as a more thorough assessment of the producible methane gas potential from coal seams within Alaska. In recent years new tools, such as in satellite imagery and soil sampling techniques, have been developed. Another gas resource that should be assessed is gas from gas hydrates on the North Slope and in Interior basins which are very sizeable and could be developed in future decades as technology advances.

Recommendation:
The State should evaluate incentives and policies to spur the exploration by private companies for natural gas, to better delineate the natural gas resources not only on the North Slope but elsewhere throughout the State. Strategies and plans should be implemented to attract additional companies interested in natural gas exploration, who now utilize new technologies, to the North Slope, Cook Inlet, the Interior basins and elsewhere in the state.

Recommendation:
A major gas pipeline should traverse Alaska if the State is to fully exploit its longer-term resource from all basins over 50-plus years and to also gain access to future multiple markets over the long-term. In addition such a pipeline could ensure long-term, reasonably priced supplies of energy to the Railbelt and other areas of the State thereby encouraging economic development.

Recommendation:
The State should facilitate favorable policies and incentives to encourage development by the private sector of a broader natural gas infrastructure within the State that meets the long-term clean energy demand of Alaskans at reasonable market prices.

Conclusions:

* Natural gas supply in Southcentral Alaska is decreasing while demand for natural gas in home and commercial use as well as for electrical demand is increasing. Additional reserves of natural gas will be needed to meet future demand.

* The natural gas demand in Southcentral Alaska in 1998 was 589 million cubic feet per day (MMCFD) and is estimated to have grown 1 - 2.5% per year over more than 30 years. Approximately 166 MMCFD is for local utilities;75 MMCFD for residential and commercial space heating use and 91 MMCFD for electric power generation. 360 MMCFD is for industrial use, 214MMCFD for LNG export and 147 MMCFD for ammonia-urea manufacture. 46 MMCFD is for fuel to operate oil and gas production facilities.

* Unless new significant gas reserves are developed, a shortfall in natural gas deliverability for peak winter demand is predicted for Southcentral Alaska by 2006-08. This deliverability shortfall may be offset by gas storage, by curtailment of industrial use or by bringing new reserves on line. However, replacement of the deliverability will add higher cost resources, substantially increasing natural gas and electricity bills for consumers and businesses in Fairbanks, Anchorage, the Mat-Su Valley and the Kenai Peninsula.

* By 2009 without significant new sources of gas, the continued operation of the LNG plant and/or the ammonia/fertilizer plant is at risk. The export license for the Kenai LNG facility expires in 2009. It is conceivable that the export of LNG plant would not be authorized beyond 2009 and rising gas prices may make it difficult for the ammonia–urea plant to compete in international markets

*In the long term, conventional natural gas (excluding coal bed methane) in Cook Inlet will probably be unable to meet the needs of the Cook Inlet region even with the cessation of all industrial uses. A long term solution to this pronounced shortfall in deliverability would be gas from the North Slope. Depending on the delivered price of North Slope gas, this may also allow the continued operation of the industrial plants, thereby saving over a thousand total jobs and maintaining property taxes and state revenues

* By 2018 in Southcentral Alaska, other fuel alternatives, heating oil and coal, may have to be relied on. In the case of fuel oil and coal, there are clean air environmental consequences for citizens in Anchorage, the Mat-Su Valley and on the Kenai Peninsula.

* Current natural gas purchases by residential and commercial users in the Anchorage area total over $100 million per year. The deliverability shortfalls starting as early as 2006 could cause natural gas prices to increase affecting business growth and corporate taxes to the State as well as affecting cost of living for residents.

* The only known proven reserve, longer-term natural gas supply solution for consumers in the areas around Anchorage will be North Slope gas which can potentially be delivered to the Anchorage area at competitive market prices via a spur line off a main trunk line.

* The most competitive priced and cleanest fuel for consumers in Fairbanks may be North Slope gas that can be delivered to the Fairbanks area through an offtake "hub" or tap in the main gas pipeline.

* Along the pipeline route from the North Slope through Interior Alaska 14 large mineral prospects within 20 miles of the gas pipeline have been identified. These mineral prospects are currently not economic with the largest cost for development being energy cost. Testimony was given that some of these mineral prospects may be commercially viable if a reasonably priced natural gas supply was available.

* The natural gas resources in interior basins and in South Alaska have not been fully explored and delineated, but earlier screening studies have indicated the presence of natural gas. Little exploration or development has taken place because of lack of transportation to market and perceived geologic risk. In some areas, very little is known about basin geology and natural gas generation and migration, yet natural gas has been recognized as present.

* Alaska has the United State's largest volume of coal beds, but little work has been done to quantify the methane gas potential from coal seams. In the Lower 48 over the past fifteen years coal seam gas production has become a major supply source near locales where pipeline transportation is available.

* Potential reserves of methane gas trapped as gas hydrates in shallower geologic formations on the North Slope or Interior basins could be very large. Recent studies in the Lower 48 and in Canada indicate trillions of cubic feet of entrapped natural gas as hydrates Numerous research and technology studies are underway by the Department of Energy and private companies to better assess the gas hydrate resource base and technologies needed to commercialize this huge resource in the future. Alaska needs to better quantify its very large gas hydrate resource base on the North Slope and in other basins of Alaska and stay abreast of technology improvements.

* Interestingly, exploration companies new to Alaska such as Forest Oil, Andex Resources, Lappi Resources, Evergreen Resources and others have shown interest in the Interior basins for new conventional gas exploration using new technologies and for coalbed methane. Four new exploration licenses totaling 4.8 million acres are underway as well as more extensive leasing of coalbed methane leases. This new exploration should continue to be encouraged through favorable State policies and incentives. If these gas resources prove to be of large size over the next 50 years, a pipeline option that offers access to markets outside the State will be necessary as in-state markets are somewhat limited in size.

* There is not a long-range energy plan for the State that positions for the marketing of natural gas from different basins, including the prolific North Slope. A pipeline traversing Alaska offers the best option to allow assessment and future marketing from all basins across the State into future multiple markets globally.

Goal #2: Assess how natural gas or natural gas products can meet the clean and economical energy needs of communities along the pipeline routing and in rural Alaska.

Recommendation:
The State should sponsor a comprehensive economic and environmental study of assessing fuel switching in certain and rural interior communities from diesel to cleaner burning propane to provide information for the likelihood of economic natural gas "hub" propane processing facilities.

Recommendation:
The State should sponsor a comprehensive economic and environmental study of assessing broader electrical power distribution to certain interior and rural communities to provide information for the likelihood of economic power generation plants near natural gas "hub" offtake points.

Recommendation:
The State should encourage private investors to initiate an economic study of creating one or two "gas hubs" for gas distribution, natural gas liquid processing, and power generation near Fairbanks and/or Delta Junction in order to foster a broader clean energy natural gas, propane and electrical distribution system within Alaska once a pipeline is endorsed across Alaska.

Conclusions:
* Because a North Slope gas pipeline will likely be heavy-walled and high-pressure, and will likely transport large quantities of natural gas liquids, any "tap" on the pipeline for local access to gas will be very expensive and may require facilities to remove the natural gas liquids. It is possible that only one or two "hubs" for gas offtake, for local natural gas use or gas-based industrial development, may be economically viable.

* To other communities without large populations, affordable and clean energy from the gas pipeline might best be distributed from gas-fired power generation at the offtake hubs, or through bulk distribution of propane more widely across interior communities and rural Alaska. Large quantities of propane, a well-known natural gas liquid fuel source, will be moved through the pipeline in large quantities and can be removed at "hub" natural gas processing facilities.

* In an economic analysis of fuel-switching in Interior Alaska, the local cost of replacement or conversion of oil-burning stoves and generation equipment must be included and the positive economics on the environment of cleaner burning natural gas, propane or electricity be assessed.

Goal #3: Assess the costs or benefits of the state taking its royalty share "in kind" for facilitation of in-state access and use.

Recommendation:
The State should retain its right to take its royalty share of gas on the North Slope "in kind" or "in value". This flexibility creates competition to maximize wellhead value for the State by either the producers or other firms such as energy trading companies interested in marketing the State's share of gas. The producers have requested a long-term commitment by the state and are asking the State to decide up front to take either "in-kind" or "in-value". The council feels the flexibility to switch on six months notice is very important, creates marketing competition and will ultimately maximize resource value. The State should not negotiate away its right to take its royalty share of gas "in-value" or "in-kind".

Recommendation:
The state could maximize the value of its natural gas royalty resource with a mixed portfolio of "in-value" and "in-kind" sales, with in-kind royalty marketed by energy trading companies such as Duke Energy, Enron, Williams Energy or major companies like them. The state should put its royalty "in-kind" gas out for bid and seek bids from multiple parties for contract terms and price. Such contracts should ask for a "floor price" equal to or exceeding the average netback wellhead price achieved by the three major producers or from "in value" sales as "insurance" that the energy trading companies are working in their marketing to beat the producers gas sales realization.

Recommendation:
When there are out-of-state sales using an energy trading company, the energy trading company will reserve the capacity and the liability associated with that capacity, and that liability will not fall back on the state.

Recommendation:
The State may choose to direct market some portion of its gas to in-state consumers using State staff, but it is recommended that sales to customers in outside markets be handled by professional energy trading firms considering the complexity of and rapid change in those markets. This would also allow those firms to absorb the risk of nominating pipeline capacity and buying hedging instruments to lessen risk on pricing of contracts.

Recommendation:
By keeping some portion of its royalty share of natural gas "in-kind", the State may be able to make some contract deals with consumers in-state at more favorable terms than the producers as the State might realize added dollar benefits through jobs and corporate taxation of value added processing such as natural gas liquids processing, petrochemical manufacturing, power generation, etc. that may not otherwise be economically viable to entrepreneurs within the State. However, there should not be a subsidy in sales of royalty-in-kind gas. The state should receive a netback price for royalty gas equal to or greater than the market-based "netback value" of gas on the North Slope.

Recommendation:
To the extent practical, the State of Alaska should enforce its "higher of " clauses on natural gas royalty as this could add value and ensure producers work hard in their marketing to obtain the best value in their sales of natural gas. When the State elects to take any share of its royalty gas "in value", existing lease terms and statutes allow the State to receive royalty payments and production taxes on the "higher of" actual proceeds or market value. Other states, as well as the U.S. Minerals Management Service, are aggressive in ensuring all producers pay this "higher of" price for royalty and relevant taxes and receives such payments from the same producers that produce on the North Slope.

Recommendation:
Because of the complexities of the natural gas industry and the differences with the oil industry, the State should form a Natural Gas Services Group with people experienced in the natural gas industry, shipping, marketing, and trading so that the State becomes even more sophisticated in understanding deals and transactions that are often involved in the natural gas business. The group would provide an oversight function on sales of royalty gas out-of-state, but could also negotiate and manage in-state sales much like the Division of Oil and Gas now manages sales of royalty oil.

Recommendation:
For more cost effective development of in-state gas infrastructure resulting in more economical transportation of state royalty gas within the State, the State should encourage entities to examine the port authority concept of tax advantaged financing for a gas "hub", spur lines and other distribution facilities.

Conclusions:
* Current North Slope oil and gas leases, and state statutes, allow state royalty production share to be taken "in kind", i.e. physically take the oil or gas and market the products itself or arrange for other parties to purchase the gas at market value contracts, or to take "in value", i.e. allow the producers to sell the products and pay the State their realized value of wellhead price after deduction of certain transportation costs. The state has the option to switch between taking its royalty share "in-kind" and "in-value" every six months. Current state law requires any "in-kind" sales, however, to obtain values equal to or higher than "in-value" sales.

* The current North Slope producers have complied with the "in kind" or "in value" lease terms and statutes in other states and on federal offshore leases for decades and have instituted internal procedures that allow them to process the selection of "in kind" or "in value" promptly. Other states and the federal government also have internal processes for administering the switch between "in kind" or "in value" as does the State of Alaska for its royalty share of oil. The producers' arguments that Alaska must decide up front on "in kind" or "in value" to ease marketing and sales administration or to bring more certainty to gas transportation or marketing are not valid considering the same producers' decades of experience administering such programs for transportation and marketing elsewhere successfully.

* The natural gas industry in the U.S. is very sophisticated in gas trading and marketing. There are energy trading companies which may be able to market the state's royalty gas for a higher netback price than would be paid by the producers if the gas were taken in-value. If so, the state's leases include a "higher of" clause which means producers would have to pay royalties and taxes on the higher of their actual netback wellhead price or the

actual netback wellhead price of an energy trader. This, in a way, creates competition and options to achieve the best possible wellhead netback value.

* In testimony from the General Land Office of Texas, Texas has similar "higher-of" clauses in their state leases that they enforce. In 2000, enforcement of the "higher-of" clauses with producers paying royalties and taxes on the highest actual netback wellhead price achieved on various leases resulted in additional revenues of $17 million. Alaska's royalty gas sales will be ten times higher than Texas' volume of royalty gas sales.

* Alaska may achieve higher prices on some of its royalty gas by allowing energy trading companies to market the State's "in kind" share. The State of Texas takes 53 percent of its royalty gas in-kind and 47 percent in value, and claims to achieve higher prices on much of its royalty-in-kind sales by achieving better negotiated pipeline tariffs, higher customer prices, or integration for power generation.

* However, the flexibility in taking royalty-in-kind is important for other reasons as well as price. First, royalty sales will allow the state to periodically test the market, to assess whether it is getting fair market prices from producers. Second, allowing energy trading companies to market royalty gas will create more competition by their accessing different customers than the producers and broadening the market exposure of Alaska's natural gas.

* While Texas is able to market its royalty gas with a small staff of state employees, Alaska should "outsource" its sales of royalty gas to the Lower 48 or other outside markets through an experienced gas trading firm. Because large volumes of Alaska royalty gas may be marketed in several of the Lower 48 gas markets or outside markets initially, a thorough understanding of and experience in those markets will be required.

* On the other hand, it may be more appropriate that the state negotiate directly for sales within Alaska of in-kind royalty gas as is now done with royalty oil, because of the better understanding of local conditions. A section within a new Natural Gas Services Group could perform this function.

* The concept of a public authority owning a segment of a natural gas pipeline within Alaska may present significant benefits for transportation of state royalty gas to in-state users. The tax advantage of a public authority, for example, would allow a lower tariff for transporting gas within the State and resulting savings could help generate more business activity by providing natural gas prices at lower prices to consumers. The netback price, however, should remain at market values.

Goal #4: Determine the "best practices" for methodologies to achieve transparency in netback pricing valuation at the wellhead and transportation to assure fair and

favorable pricing for in-state gas business creation and expansion as well as for taxation and royalty calculations.

Recommendation:
The state should keep a natural gas price netback valuation methodology based on actual sales proceeds, or sales contracts, and not change to a formula linked to average prices in gas trading hubs or some other general formula at least for the first several years of major gas sales. The State's right under lease terms and statutes to obtain actual realized prices for its gas and natural gas liquids should not be negotiated away.

Recommendation:
With the growing natural gas liquids (NGLs) business in the U.S., the State should keep a natural gas liquids price netback of gas-line liquids based on actual sales proceeds, or sale contracts, of the liquids and not accept a value for the liquids based on a BTU adjusted basis of the gas stream unless there is clearly a higher value obtained by BTU-based sale. The State should be very sophisticated in its assessment and knowledge of the business of NGLs, as revenues from NGL sales will be a substantial part of revenues from the overall gas stream.

Recommendation:
Alaska statutes should be reviewed and updated to require information on sales spot transactions, sales contracts, actual transportation costs, and other information be made known to the State, much as statutes in Texas and other locations provide for. When updating these statutes the process should be clarified in a way that assesses the "lessons learned" on the Alaska oil valuation disputes, and provide for more timely resolution of any differences in valuation.

Recommendation:
Alaska statutes should be reviewed and updated to require information on "affiliated sales" by producers be made known to the State, much as statutes in Texas and other locations provide for.

Conclusions:
* After several years of North Slope oil production disputes arose on netback pricing valuation that resulted in major hearings and extended litigation. The state was able to resolve these issues after several years of production once access to oil sales contracts, invoices, and transportation charges allowed the state and the producers to agree on a formula for purposes of calculating royalty. The experience with production made both the state and producers confident that the formula tracked market values, or actual proceeds of oil sales. This history may or may not be of value in regard to gas price valuation. Certainly it is in both the State's and the producer's interest to avoid replication of the lengthy disputes on royalty and severance taxes experienced with the first decade of North Slope oil production

*In contrast to oil, there have been no sales of North Slope gas, nor are gas sales contracts in place or other similar information available. For the first several years of natural gas production, the state should certainly rely on existing measures of royalty value in the lease, which include value based on sales proceeds. The state should, however, review the oil valuation disputes and see if additional clarification of information, data, definitions, etc. is required to achieve a better mutual understanding by the producers and the State to lessen points of future disagreement. An agreement on an alternative formula for royalty valuation on gas may never be needed to maximize value to the state. In the future there could be sufficient production experience to allow agreement on a formula for valuation if needed. Billions of cubic feet of natural gas are sold from various states and federal leases under the actual netback pricing mechanism. While there have been disputes, there have rarely been pricing formula agreements adopted in lieu of an actual netback pricing approach.

* Natural gas hub spot prices could be too easily affected, at certain times and at certain locations, by market forces external to Alaska. This concern of hub posted prices for oil was evidenced by the Federal Trade Commission forcing a sale of oil trading hub facilities in the Cushing area because of the concentration of ownership of facilities at that trading hub location by BP, Amoco and ARCO upon their mergers. While the FTC did not claim unfair trading affecting oil hub posted prices would or was taking place, the FTC did feel too much concentration of power at such trading hubs could affect posted prices. It may be possible that concentration of interests and gas trading spot volumes at certain gas trading hubs periodically in the future could potentially skew hub prices similar to the FTC concern. Alaska should simply use the maximum, actual realized price as fair market value.

* Information on sales spot transactions, sales contracts, actual transportation costs, and other related information will ensure that reliable data is provided so the State can accurately calculate actual realized wellhead netback gas price. Such information is provided by the North Slope producers on other states' leases where required and on many federal leases. Companies have internal record keeping and software systems in place to timely provide such information for accurate calculation of netback gas prices.

* Having information on "affiliated sales" will ensure the State has knowledge when a producer sells natural gas to an affiliated subsidiary company for additional value added marketing, processing or manufacturing. Having such knowledge of affiliated sales can help the State screen that a fair market value is being obtained for the gas versus a value being obtained that is less than market while the affiliate captures additional value downstream.

* Testimony to the Subcommittee showed that Texas bases its royalties on actual proceeds, and requires producers to report to the state, on a monthly basis, information on

sales contracts, points of sale and transportation costs. Texas General Land Office staff has developed computer software to track these transactions and to ensure the accurate calculation of lease netback for purposes of producers, in turn, calculating accurate royalty and tax payments. The companies that report these transactions in Texas include all three of the major gas producers on the North Slope. Texas has offered to make its computer models used in monitoring transactions available to Alaska.

Goal #5: Recommend policies that assure clear and transparent rules for access to natural gas into and out of the gas pipeline for Alaska businesses and customers.

Recommendation:
The State must develop a clear and sophisticated understanding of the "open season" rules governing access to a contract carrier pipeline, and devise strategies to facilitate access to the pipeline for firms exploring for or developing new gas discoveries on the North Slope or Interior basins.

Recommendation:
The state should incorporate in any federal legislation the right to gas access in-state. This right is provided in ANGTA but not provided in the producers' recently proposed federal legislation.

Recommendation:
The state should first seek federal legislation that gives the RCA authority to set tariffs for the transportation of intra-state gas used in state similar to that authority given to the RCA for tariff review on the TAPS oil line. The state RCA should review applications for pipeline access within the state to ensure fairness in pre-determined fees and terms based on reasonable rates of return for investors who ship to in-state consumers.

Recommendation:
Failing to achieve RCA obtaining sole authority in-state, the state should seek through federal legislation the creation of a Joint Board between the Regulatory Commission of Alaska and the Federal Energy Regulatory Commission that would have authority to set tariffs for the transportation of intra-state gas used in state. This joint board should participate in review of applications for pipeline access within the state to ensure fairness in pre-determined fees and terms based on reasonable rates of return for investors who ship to in-state consumers.

Recommendation:
Alaska should consider including a "fairness" clause in the granting of state right-of-way approvals across state lands to guarantee fair access, similar to provisions developed by Texas for pipeline rights-of-way approved across state lands. Such a clause will give the

state valuable leverage in negotiating fair access rules. The clause could also provide an avenue for appeal to the RCA in the event of disputes.

Recommendation:
The state should complete a thorough socio-economic study of various approaches to in-state natural gas pricing of in-kind royalty gas.

One approach is that the sales price of in kind royalty gas or gas liquids to in-state users, whether private or state, be based on the market netback price of gas on the North Slope (which is determined by subtracting actual pipeline transportation costs from actual realized market sales prices in the Lower 48 or other outside markets) adjusted for intra-state tariffs actually incurred for the transportation of the gas to the in-state access point, or hub, and then transportation costs to the consumer with allowance for an reasonable rate of return on investment. Price of gas or gas liquids to in-state users should not be based on comparisons with alternative fuels, such as diesel. Providing that the intra-state tariff is determined on a prorated basis and not the "postage stamp" methodology, this policy will create a supply of reasonably priced, clean energy for communities in Interior Alaska, and ultimately Southcentral Alaska if a spur line is built. These more affordable natural gas prices would passed along to consumers who purchase from a regulated utility but may not be passed along to consumers who purchase from a non-regulated company. A problem with this approach is that the State receives a potentially lower netback value than if the price is determined through competition with other fuels. This may favor the consumers in that area at the cost of lower State revenues. On the other hand, such an approach could mean more affordable natural gas to a large number of customers who purchase from regulated utilities, potentially enhancing economic development and quality of life for businesses and consumers.

Another approach is that the sales price of in kind royalty gas or gas liquids to in-state users should be based on being competitive with the pricing of alternative fuels. as that may create higher netback prices resulting in higher royalty and tax revenues to the state. This would potentially increase the revenue received by the State but would not significantly lower the costs of consumers using this in-kind gas or gas liquids. However sellers other than the State could compete for these higher netback markets and so drive the price down well below the alternative fuels.

Conclusions:
* Some existing, large pipeline companies in the Lower 48 have built pipelines with spare capacity as a speculative investment, allowing for future growth in volumes and revenues. Some pipeline companies do not invest in speculative capacity. Producers also

tend not to invest in speculative, spare capacity but tend to construct to immediate capacity needs.

Without spare capacity in the pipeline, it is very important that the State have a clear understanding of the "open season" rules and how to position for new entrants being allowed to produce into the pipeline.

* It is recognized that with a thick-wall, high-pressure pipeline, access taps and liquids processing facilities will be expensive. Points for gas offtake might be limited economically and operationally to only one or two distributions "hubs" along the pipeline route in Alaska.

* With a limited number of "hubs" for offtake, it may be more economical for several Interior and rural communities to obtain the clean energy not by direct natural gas use, but by benefiting from potentially economic electricity generation and natural gas liquids (propane) distribution from the centralized "hub" location(s).

* To fairly govern gas taken off at an in-state distribution hub(s), general access terms should be developed in advance by the RCA (or the Joint Board of RCA and FERC)that are clear and understandable. Similar general terms have been developed to govern contracts at gas trading hubs in the U.S., United Kingdom and the European Union.

Goal #6: Assess pipeline sizing and the pipeline "contracted volumes" structure for growth of in-state use and/or potential future export markets to Asia and the West Coast, or expansion of deliveries to the Lower 48.

Recommendation:
The state should investigate ways of working with pipeline transmission companies as investors to build in excess capacity, to provide space for transporting new gas that will be discovered on the North Slope or Interior basins.

Recommendation:
The State should evaluate innovations in using part of its "in kind" royalty share in contract sales to energy trading companies who can bid for shipping capacity which then may be used in a creative way in the future to ship gas from new discoveries while the State elects at the time of new discoveries to change and sell the originally nominated royalty gas volumes "in value".

Recommendation:
The state should seek an order by FERC or federal legislation for periodic open-season nomination periods, to allow for additional capacity to be built for new gas, when

triggered by requests from existing or potential producers, transporters, shippers, customers, or the state.

Conclusions:

* Failure to provide for additional capacity either at startup or through future open seasons could have the effect of creating a "monopoly" on pipeline capacity by existing producers, discouraging exploration by others who are not owners of the pipeline.

* Strategies for natural gas pipeline open season nominations and shipping arrangements become very complex. A new Natural Gas Services group could have such expertise in-house or these skills could be out-sourced to experienced gas trading firms.

* Because of current lease terms and statutes, the producers must allow to have enough capacity and construction size to ship the entire volume of the State's royalty share of gas "in value" if the State were to elect at any time to have its royalty share sold direct by the producers.

Goal #7: Evaluate conceptual options for future value-added projects during the fifty-year life of gas reserves for in-state use and/or export to Asia and the U.S. West Coast.

Recommendation:

No one can rule out with certainty the viability of value-added processing of natural gas in Alaska over the next 50 years. Alaska should have a natural gas pipeline that allows this option to remain open. The previous recommendations regarding access, reasonable tariff and pricing, and capacity expansion will keep these options open.

Recommendation:

Gas and gas product markets are highly cyclical in price and somewhat cyclical in demand, and somewhat regional in nature thus the State should facilitate a pipeline option that will allow access to multiple markets in the future.

Recommendation:

As markets change, the state should take a proactive role in encouraging investors to consider the possibilities for liquefied natural gas (LNG), gas-to-liquids (GTL), expanded uses of natural gas liquids (NGLs such as propane, butane), and downstream processing such as petrochemicals.

Conclusions-General:

* Original investors in the Trans-Alaska Pipeline System, the producers, estimated the life of the North Slope oil fields at 25 to 30 years. Twenty-five years have passed since startup of the TAPS line, and these investors are now applying for a 30-year extension to

the rights-of-way for TAPS, so that oil developed since the pipeline startup can be shipped to market.

* The same circumstance may develop for North Slope gas, as exploration continues on the North Slope. Accordingly, the state should position itself for a 50-year life for a new natural gas industry and encourage development of a system that will access multiple markets. Only a gas pipeline following the southern route will be able to access additional markets through a spur line to an LNG plant on the southern Alaska coast.

* Oil and gas are commodities, and all commodity markets experience supply/demand and price cycles. If Alaska has access to multiple markets for gas, to the Lower 48 through an all-land pipeline, to the U.S. West Coast and Asia through LNG shipments, and into the growing petrochemicals industry through sales of gas and natural gas liquids, the state will benefit because the commodity cycles may be different in these markets at different times as has been past history. In the future, there could be a more uniformly priced global gas market, however, there will likely remain cycles in volume demand or demand trends by regions.

* There is also the longer-term potential for a gas-to-liquids industry, with plants in Alaska manufacturing clean-burning liquid fuels directly from natural gas, and for development of new industries related to the petrochemicals industry. These may be important future "value-added" industries for the state over the long-term.

Conclusions-LNG

* Both Cambridge Energy Research Associates and the gas producers have provided information to the Committee that the cost of delivering LNG to Asian markets is currently not competitive with LNG supply from other sources, such as Indonesia, Malaysia, Australia and the Middle East.

* Yukon Pacific Corp., the Alaska Gasline Port Authority and a citizens' group have presented information that they believe LNG exports from Alaska is currently competitive. Yet none of these organizations have secured substantial financial backing or presented firm contracts for sales of LNG.

* Despite this, no one has presented information that rules out LNG in the future. Asian nations may want to secure large-scale supplies of LNG from Alaska for purposes of energy security, to not be dependent on one or two regions such as the high-risk Middle East for the majority of import needs. Therefore, it is in Alaska's interest to maintain the flexibility to be able to supply LNG to export markets, or to U.S. West Coast markets, in the future.

Conclusions-GTL:

* Large-scale gas-to-liquids projects, the making of clean-burning liquid fuels from natural gas, could be an option for North Slope producers if they do not proceed with a gas pipeline project. These liquids could be shipped down the existing trans-Alaska oil pipeline. Testimony from the producers and information presented at a recent international conference on gas-to-liquids, held in Girdwood, indicate that large-scale application and commerciality of such a remote resource of gas as the North Slope reserves using GTL technologies may be 10 years in the future, if ever, versus competitive sources of gas elsewhere that could use the GTL technologies.

* There is sufficient potential for growth of North Slope gas reserves, and the expectation is that there will be sufficient reserves established for both a conventional gas pipeline and gas-to-liquids plants, once it can be shown that Alaska GTL plants can be commercially viable on a large scale.

* A possible negative for a stand-alone GTL project, without a gas pipeline is that it would lock Alaska into one market for its gas, the West Coast fuels markets. It may not be cost competitive to serve other markets with GTL fuels from Alaska because of shipping distances. However, if a gas pipeline is built, GTL could be a potential value-added product that reaches a different market, the future demand for clean-burning fuels on the U.S. West Coast.

Conclusions-NGLs

* Information presented at the Girdwood GTL gas conversion conference indicates major breakthroughs in cost-reductions of processing natural gas liquids through related technologies. Costs of processing NGLs today is seen as much less than was the case a few years ago. This could serve to enhance the viability of a gas pipeline that also carries NGLs to market.

* The NGL business in the U.S., mainly in propane and butane, is a very large multi-billion dollars industry and a key component of the integrated natural gas industry. The producers are studying the construction of a large NGL extraction plant in Alberta.

* A gas access and distribution hub(s) built near Fairbanks or Delta Junction could facilitate expanded production and sale of NGL products in the state, for distribution to Interior or rural communities. Fuels from NGLs have the potential for becoming an economic and clean-burning alternative source of energy for Alaska communities. The Williams Companies and other firms in Fairbanks are now assessing investment opportunities and potential for uses of NGLs.

Conclusions-Petrochemicals:

*A previous assessment of a petrochemical industry for Alaska, done by Dow-Shell, found that a petrochemical industry would not be viable in Alaska at the time that study was done. However, changed circumstances have affected several assumptions used in

the study. Dow-Shell assuming that a separate, small-diameter gas liquids pipeline would be built from the North Slope, and envisioned an industry based on manufacturing complex petrochemicals.

* Today there is a proposal for a natural gas pipeline that could also carry NGLs, so there is no need for a separate pipeline. Also, one new study underway of using NGLs, by Williams, envisions manufacturing a simpler petrochemical product than that envisioned in the Dow-Shell study.

* Williams' study is considering the making of polypropylene, one of several petrochemical products in the olefin family, and shipping the product via the Alaska Railroad to Anchorage for shipment to markets in Asia. Olefins are fundamental feedstocks for the rapidly growing plastics industry. It is a business involving $41 billion in annual sales, with significant supply shortfalls expected in 2006. Williams has completed an initial screening study and is now engaged in a more detailed analysis of its study.

* All three major producers on the North Slope have recently expanded their olefins business in the Lower 48. All three of the major producers have extensive separate businesses in olefins in the U.S. and Canada. For example, ExxonMobil is ranked as the number 3 producer of ethylene in North America, while Phillips-Chevron is number 4, and BP is ranked number 7.

Goal #8: Determine strategies to promote and attract investment for in-state distribution and value-added processing.

Recommendation:

The state should develop and periodically update a formal marketing plan to attract investors in Alaska who may be interested in in-state gas distribution or development of value-added industries. Assisting this could be an additional function of a new Natural Gas Services group within the Department of Natural Resources.

Conclusions:

* It should be recognized that Alaska businesses, such as Enstar and Fairbanks Natural Gas Company, have already voiced interest in developing more in-state distribution.

* While the scale of in-state processing may not be attractive to the major producers, in-state value added businesses may be of interest to Alaska Native Corporations and other Alaska companies once a gas infrastructure exists.

DRAFT
Committee Report
Environmental Considerations Committee
Peg Tileston, Chair

Goals:

- To define and address key environmental issues, both natural and human, associated with the construction of a natural gas pipeline.
- To make recommendations for policies and procedures necessary to ensure that the design, construction, and operation of the natural gas pipeline will proceed in an environmentally sound manner.
- To identify potential environmental benefits of a natural gas pipeline.

Introduction and Background

The proposed Alaska natural gas pipeline project is comparable to the Trans-Alaska Pipeline System (TAPS), which was built in the mid-70s to transport crude oil from Prudhoe Bay to the Valdez Marine Terminal. The gas pipeline under consideration is proposed to be large-diameter (up to 52 inches), high-pressure, chilled, completely buried (except for above ground crossings of the Yukon River and possibly the Tanana River), and supported by a number of compressor stations. In addition, a large conditioning plant will be required on the North Slope to treat the natural gas before it enters the pipeline. Furthermore, the proposed Highway route would be international, crossing portions of the United States and Canada and thus requiring trans-boundary coordination of the pipeline's daily operation, maintenance, and emergency response capabilities. Except where noted the comments in this report deal solely with the Alaska segment of the proposed gasline.

Much has been learned from the TAPS experience over the last 27 years. When the State of Alaska and federal agencies undertook oversight of the design and construction of the TAPS project, they embarked on a new frontier and there was limited understanding of the impacts and problems associated with a project of that magnitude. Delays caused by litigation provided industry and agencies with an opportunity to review and improve TAPS engineering design and construction planning. This review resulted in successes, but there were also unanticipated failures. Careful planning and design, as well as continuing vigilance in monitoring and enforcement are essential to reducing environmental concerns.

Oversight and regulation of TAPS have been enhanced over time due to a commitment to continuous improvement of the oversight process by industry, government and the public. In the early 1990s, the Joint Pipeline Office (JPO) was established to provide a coordinated, cooperative federal-state structure for oversight of the line. This has proven to be an effective inter-agency oversight mechanism. A similar joint office, the Gas

Pipeline Office (GPO), has been established for the natural gas pipeline, and it is important that it be adequately funded and staffed with highly qualified personnel to provide the needed agency liaison and coordination of the permitting standards and process.

The impacts of a project of this magnitude will be extensive, particularly during the construction phase, and must be considered not only in the context of the natural environment but also as it will affect the human environment. Quality of life in communities can be degraded in numerous ways ranging from reduced services, traffic congestion, crowded schools and health services, reduced recreational opportunities, and inflationary pressures. Rural residents depending on subsistence may experience increased industrial and recreational activities in traditional hunting and fishing areas. On the other hand, pipeline construction will create jobs and increase short-term economic opportunities, and the completed pipeline could supply natural gas to communities that presently depend on less efficient liquid petroleum products for energy, altering lifestyle and environmental patterns ranging from fuel consumption to air quality over the long term.

The charge for the Environmental Considerations Committee of the Natural Gas Policy Council is to make recommendations to assure that the project follows Governor Knowles' policy of "doing it right." The committee has determined that its most effective contribution is to recommend needed policies and procedures, many of which should be put into place as early as possible during engineering design and prior to the start of construction. Every effort must be made to ensure that best technology and best environmental practices are implemented in order to make the project as environmentally benign as possible, and to make sure that the net impact on human lives will be positive. The following recommendations to decision-makers are presented with these goals in mind.

Recommendations and Supporting Rationales

1. Endorse the Alaska Highway gas pipeline route as the environmentally preferred pipeline route that minimizes the potential adverse environmental effects and maximizes potential environmental benefits to Alaska.

An Alaska Highway route would limit the gasline to an existing corridor, minimizing impacts to the environment as well as to fish and wildlife. It would also allow Alaska communities access to a cleaner, more efficient fuel. In addition, a highway route following the TAPS line would make oversight of both lines more efficient and effective. At hearings of the Gas Policy Council, Alaskans voiced overwhelming support for the environmentally preferred southern route.

Any frontier route would require a "start from scratch" approach, including collection and analysis of physical, biological, and social data and determination of required technology.

2. Recommend that the GPO conduct a thorough review of "lessons learned" from TAPS design, construction, and operation. This review should include public comment and public participation. Use "lessons learned" to develop procedures for the gas pipeline that ensure past mistakes are avoided and successes repeated.

A natural gas pipeline following the TAPS/Alaska Highway corridor will have many environmental concerns similar to those of the earlier project. Certain differences need to be identified and addressed, such as the effect of a buried, chilled pipeline crossing beneath streams, geologic and hydrologic data for areas where TAPS is not buried, and design and operational differences between a low-pressure, hot oil line and a high-pressure, cold gas line. In addition, Canadian and other high-latitude gas pipelines should be studied for lessons learned.

A rigorous environmental review should be required and could be done either by a supplemental environmental impact statement (EIS) building on the ANGTS EIS or a full EIS done in an expedited manner using information from the ANGTS EIS. The outcome of either process should spell out for public review the full range of alternatives, environmental pros and cons associated with them, and mitigation measures that should be taken to avoid or minimize adverse impacts.

3. Adequately fund and staff a natural gas pipeline office that is housed in one place to facilitate communication, coordination, and cooperation among all affected state, federal, and Canadian agencies.

Lack of timely and complete communication among agencies can have severe consequences on any project, but can be particularly difficult in one of this size. A facilitated review of the JPO operation by all the involved agencies to note procedural changes they might recommend to improve effectiveness and efficiency would be beneficial. Acquiring personnel with the necessary technical and scientific expertise may be difficult for both federal and state agencies when competing with industry, which will be hiring for the same positions and will have considerably higher salary scales. Every effort should also be made to include the considerable number of borough and local agencies concerned with the various project alternatives, along with Alaska Native corporations, tribes, and villages that will be affected by a pipeline right-of-way (ROW).

4. Establish an open and available data and information process for the public, agencies, and industry.

Frustration and suspicion take hold when individuals, organizations, and communities are unable to get information on issues of concern in a timely and appropriate manner. Such a process should start at the beginning of the project and make available all non-proprietary material. Meaningful involvement by affected communities is important. Effort should be made to include all stakeholders, not just decision-makers. Websites, e-mail addresses, and information repositories, such as local libraries, borough offices, and central sites such as the Alaska Resource Library & Information Services (ARLIS) should be used as effectively as possible and adequately funded. An information clearinghouse such as the Exxon Valdez Oil Spill Library (which is now consolidated in ARLIS) could be an appropriate approach.

5. Establish mandatory training for all personnel involved with the gas pipeline project.

Timely, appropriate, and sufficient training is vital for all personnel associated with a major project. Such training should start with applicable federal, state, and local laws and regulations, agency mandates and responsibilities, enforcement options and penalties for noncompliance, best practices, and appropriate technologies. Government and industry should coordinate to ensure commensurate levels of training for the public and private sectors, including all contractors and subcontractors. Sessions to update personnel as the project progresses should be included, along with required orientation for those joining it.

6. The state should take a long-term view of the gas pipeline to minimize environmental concerns.

In view of the likely long-life of this project, the state should encourage a long-term view be taken in design, construction, operation, and maintenance in order to mitigate environmental risks over the entire life of the project.

7. A records management system for compiling and maintaining complete and updated documentation should be in place at the beginning of the project and maintained and updated throughout the life of the pipeline in accordance with professional document control standards. The state must have copies of all documents.

The TAPS experience has shown that older engineering drawings, including "as-builts"

and documents confirming original facility configurations and placements, have not always been readily accessible by pipeline managers and regulators when needed. Establishing a professionally designed and maintained document control system will help to ensure that accurate records from every phase of pipeline development remain rapidly retrievable under unforeseen future circumstances. This process will undoubtedly be aided by recent advances in technology.

8. Assure that effective and adequate monitoring and enforcement systems are in place at the start of the project and continue throughout the life of the pipeline.

Adequate funding will be needed to ensure that a sufficient number of appropriately trained agency personnel are available for monitoring and enforcement throughout pipeline construction and operation. Agency personnel without a working knowledge of pipeline construction, operation, and maintenance will have little credibility with their industry counterparts. Training of agency personnel associated with all aspects of the pipeline should be integral to the project. Such training should emphasize the prevention and early detection of problems, and understanding of regulations, codes, and penalties. Enforcement of regulations and codes is essential but will not occur without trained personnel who are actually available on site.

9. Direct the GPO to establish a comprehensive citizen's involvement plan. This effort may include the creation of a citizen advisory council with representatives from communities affected by construction of the pipeline.

A determined effort should be made to aggressively involve and engage affected communities during the planning and construction phase through a coordinated federal/state effort. If necessary as determined by the federal/state plan, a citizen advisory council should be formed and adequately funded to receive and evaluate information and respond to pertinent issues. If established, the council would also evaluate their role following construction of the pipeline.

The public involvement process should also include a full review, including stakeholder involvement, of proposed federal grant and state lease right-of-way provisions and stipulations.

10. Provisions should be incorporated into ROW lease agreements to ensure that adequate DR&R funding will be available for the Alaska segment of the natural gas pipeline.

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The actual DR&R provisions will depend on ownership of the pipeline and should take into consideration the long-life of the asset.

11. Perform a full security review and develop a comprehensive and detailed security plan early enough to influence the pipeline design and alignment process.

Heightened security concerns throughout the United States should be reflected in the engineering design and alignment of the natural gas pipeline, which will be a significant part of America's domestic energy supply. Any aspect of the design of pipeline facilities and structures that would be particularly vulnerable to sabotage, such as compressor stations, bridge crossings, and above-ground valve housings, should receive attention from a security standpoint early in the design process, and not as an afterthought. This concern applies also to the alignment, which may present opportunities for modifications or adjustments that will minimize the potential for harm.

12. Continue to ensure that environmental scientists and permitting specialists work side-by-side with design engineers and construction planners from the earliest stages of the project through to its completion.

It is essential that environmental safeguards be built into the design of the project, not added as an afterthought to satisfy regulatory requirements and stipulations. Preliminary engineering design products will be used to support major permit applications with long lead times and must contain fully integrated environmental features at that early stage. This can best be accomplished if environmental and permitting specialists work on the same teams and in the same facilities as the engineers.

13. The State of Alaska ROW lease should require long-term environmental surveillance and monitoring, and annual reporting. This function should continue throughout the life of the pipeline.

14. The GPO, in cooperation with the federal government, should continue to coordinate the trans-boundary aspects of construction, operation, and maintenance of a gasline, including operations control and emergency response.

Although it may cross land belonging to two nations, the gas pipeline will be a single integrated system. Emergencies, whether structural, operational, or environmental, will not respect the international boundary. The U.S. and Canada must establish integrated control

protocols that can regulate the pressure and flow of gas through the pipeline as a single system and thus respond quickly and effectively to emergencies. This will require open communications, shared data, and a close working relationship between personnel of both nations. It may be necessary to establish an international commission to coordinate this effort. The state should look to other international pipelines for models in handling the trans-border oversight aspects of construction, operation and maintenance.

BRISTOL BAY NATIVE ASSOCIATION
P.O. BOX 310
DILLINGHAM, ALASKA 99576
(907) 842-5257

Bristol Bay Alternative Energy Task Force

Resolution 2001 - 01

ALASKA' PROPOSED NATURAL GAS LINE

WHEREAS, the Constitution of the State of Alaska states in Article VIII, Section 2., that the legislature shall provide for the utilization, development, and conservation of all natural resources belonging to the State, including land and waters, for the maximum benefit of its people; and

WHEREAS, despite Alaska having an oil pipe line, home heating and gasoline costs in the Bristol Bay region are extremely high, for example: Dillingham residents are paying $2.29 per gallon for #1 home heating fuel and $2.59 per gallon for gasoline; Aleknagik residents are paying $2.60 and $2.75 respectively; Iguigig residents are paying $2.94 and $3.63 respectively; Nondalton residents are paying $3.05 and $3.30 respectively; and

WHEREAS, the majority of Bristol Bay communities are solely dependent upon diesel generators for electricity and pay among the highest electric rates in the state, as much as 2 to 4 times more than Anchorage, Matanuska, and Kenai residents; and

WHEREAS, high energy costs in the Bristol Bay region has a direct impact on the cost of living, transportation, maintaining public buildings; and operating water and sewer systems; and

WHEREAS, one of the cornerstones of economic development is to have access to cheap electrical power, and high energy costs currently hinders the economic development efforts of rural Alaskan communities; and

WHEREAS, with natural gas being cheaper and cleaner burning than diesel oil, Bristol Bay residents would like to have access to natural gas for the purposed of providing electricity and heating their homes; and

NOW, THEREFORE, BE IT RESOLVED by the Bristol Bay Native Association's Bristol Bay Alternative Energy Task Force that Alaska's State Legislature, the Governor's Office, and Alaska's Congressional Delegation, ensure that all Alaskan communities be provided access to natural gas from the proposed North Slope gas line, or the proceeds therefrom be used to inflation proof Alaska's residents escalating energy costs.

Signed: Terry Hoefferle
Chairman

CERTIFICATION:

I, the undersigned Recording Secretary of the Bristol Bay Native Association, do hereby certify that the foregoing resolution was duly passed the majority vote of BBNA's Bristol Bay Alternative Energy Task Force at a duly called and noticed meeting this 16th day of April, 2001 and that a quorum was present.

Signed Andrew Holsi
Recording Secretary

JUNEAU CHAMBER OF COMMERCE

3100 Channel Drive, Suite 300 ◆ Juneau AK 99801

(907) 463-3488 ◆ Fax (907) 463-3489

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CC: GOV/COS

AUG 2 0 2001

OFFICE OF THE GOVERNOR

August 15, 2001

Office of the Governor
Attn: Natural Gas Policy Council
PO Box 110001
Juneau, AK 99811-0001

Thank you, Received
Steve W.

The Juneau Chamber of Commerce's Board of Directors support the Alaska Highway route for the natural gas pipeline because it has the potential to provide significant economic benefits for the greatest number of Alaskans.

During the construction phase, the highway route would enable Southeast Alaska port communities (Haines Skagway, Juneau, Ketchikan, Hyder) to serve as staging areas and sources of supplies for the project itself and construction crews.

However, it is critical for the Natural Gas Pipeline Policy Council, in its formal recommendation to Governor Knowles, to specifically include spur lines from the main pipeline to the Railbelt area and at least one port in Southeast.

The primary source of heating and electric energy for the Railbelt area is natural gas from the Kenai Peninsula. Recent estimates indicate natural gas resources for this area could run short as early as 2008. It is imperative for the continued economic health and welfare of the Railbelt area that additional natural gas supplies be made available via a spur line from the proposed Alaskan Highway Natural Gasline.

Haines and Skagway could easily be developed as spur line delivery ports to deep-sea vessels. Haines is the shortest route to tidewater of any port along the Alaska Highway route and the Southeast Conference is on record supporting such a development for Haines. In addition to providing Haines

with year-round jobs for that economically depressed community, location of a pipeline spur to Haines or Skagway would provide another source of energy to Southeast Alaska communities.

Sincerely,

Jamie Parsons
Executive Director



Copper Valley Electric Association, Inc.

P.O. Box 45 • Glennallen, Alaska 99588 • Telephone: 907-822-3211 • Facsimile: 907-822-5586 • Valdez: 907-835-4301

Erika/Debra, a thank you from us?

August 27, 2001

Ken-59413
CC: GOV/COS

E-mail: wilkinson@cvea.org

RECEIVED

SEP - 4 2001

OFFICE OF THE GOVERNOR

Office of the Governor
Attn: NGPC
P. O. Box 110001
Juneau, Alaska 99811-0001

SUBJECT: Governor's Gas Line Committee

The purpose of my letter is to write in support of a gas line project that would benefit the maximum number of Alaska residents. I believe that project includes a gas line to Delta with separate lines following the Alaska Highway and to tidewater in Valdez.

CVEA is a non-profit, member-owned electric cooperative. We serve 3,500 customers in the City of Valdez and the Copper River Basin, and our service area, which is geographically the size of West Virginia, includes 156 miles of the pipeline corridor along the Richardson Highway. The region is vast, and providing reliable electric service in some of the most difficult climatic conditions in the world is a challenge to say the least, it is also very expensive.

CVEA is not interconnected electrically to other regions of the state. We produce electricity at four power generating stations within our service territory. The fact that we operate and maintain four generating stations accounts in large part for the high cost of electricity for the region, which today in Valdez is 16.4¢ per kilowatt hour, not quite double that of the Railbelt area.

In the mid-1990s, in an effort to reduce the high cost of electricity to the region, CVEA pursued developing a transmission line project to interconnect our utility with the Railbelt Energy Grid. The purpose of that project was to access less expensive Railbelt energy.

In 1996, CVEA set the proposed intertie project aside in part due to the realization that it did not complement a possible gas line project. In fact, an LNG project has far greater energy potential for the region including the potential to make Valdez or the Copper River Basin an exporter instead of an importer of energy.

A LNG facility produces an enormous amount of heat, and according to the Port Authority Consultant, Mr. Boynton, the proposed project produces on the order of 280 megawatts of usable heat. This heat can be harnessed to produce steam, which in turn can drive turbines to produce electricity. Depending upon the capital cost of the project and the cost of the heat, electricity produced at the LNG facility could be very cost effective compared to electricity generated with Cook Inlet gas. That energy could be delivered to the Railbelt region cost effectively via a high voltage transmission line.

The Valdez/Copper Basin regions are poised for economic development as evidenced by construction of the Princess Hotel near Copper Center and the new National Park Service visitor center, both of which are scheduled to open in mid-2002. These projects, coupled with the strategic transportation corridors along the Glenn, Richardson, Alaska and Marine highways, are all indicators the region has tremendous potential for future economic growth.

CVEA is excited about the future of the region and our ability to deliver cost effective energy solutions to fuel future prosperity. A gas project through Glennallen to Valdez, capable of serving west coast and world markets not to mention the 800 miles between the North Slope and tidewater, would be a major cornerstone in developing a sustainable economy for the state of Alaska at a critical time when timber, fishing, and even the oil industry are in decline. In addition, a spur line to Anchorage along the Glenn Highway would augment declining gas reserves in the Cook Inlet region.

I would like to close on a personal note. I am a 42 year resident of the Great Land. When I moved to Anchorage with my family in 1959, Alaska's largest city had less than 20,000 residents. I remember the bumper sticker "I drove Tudor Road and survived." Since that time the State has benefited from tremendous growth and prosperity; however, I am uncertain of how bright the future is, particularly if our resources are extracted to benefit others. Alaska's resources should be developed to benefit Alaskans. Developing a gas project aimed at maximizing corporate profits while ignoring sustainable, long term economic prosperity for Alaskan residents makes little sense to me. As the Council completes its very important work, I urge you to carefully consider what is in the State's long term best financial interests and the interests of 630,000 Alaskans who are proud to call the Last Frontier home. I urge you to support the Alaska Gas Line Port Authority in developing a gas line project that ensures long term prosperity and a bright economic future for Alaska.

Sincerely,

Robert A. Wilkinson
Chief Executive Officer

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Testimony before Governor's gas line committee
August 23, 2001

- My name is Robert A. Wilkinson and I am CEO of Copper Valley Electric Association
- I am here today to testify in favor of a gas line project which would benefit the maximum number of Alaska residents. I believe that project includes a gas line to Delta with a with separate lines following the Alaska Highway and to tidewater in Valdez.
- CVEA is a non-profit, member owned electric cooperative. We serve 3,500 customers in the City of Valdez and the Copper River Basin and our service area which is geographically the size of West Virginia includes 156 miles of the pipeline corridor along the Richardson highway
- The region is vast and providing reliable electric service in some of the most difficult climatic conditions in the world is a challenge to say the least, it is also very expensive.
- CVEA is not interconnected electrically to other regions of the State, we produce electricity at 4 power generating stations within our service territory. The fact that we operate and maintain 4 generating stations accounts in large part for the high cost of electricity for the region which today in Valdez is 16.4¢ per kilowatt hour, not quite double that of the Rail belt area
- In the mid 1990's in an effort to reduce the high cost of electricity to the region, CVEA pursued developing a transmission line project to interconnect our utility with the Rail belt energy grid. The purpose of that project was to access less expensive Rail belt energy.
- In 1996, CVEA set the proposed intertie project aside in part due to the realization that it did not complement a possible gas line project. In fact, an LNG project has far greater energy potential for the region including the potential to make Valdez or the Copper River Basin an exporter instead of an importer of energy
- An LNG facility produces an enormous amount of heat and according to Mr. Boynton the proposed project produces on the order of 280 MW of usable heat. This heat can be harnessed to produce steam which in turn can drive turbines to produce electricity. Depending upon the capital cost of the project and the cost of the heat, electricity produced at the LNG facility could be very cost effective compared to electricity generated with Cook Inlet gas. That energy could be delivered to the Rail belt region cost effectively via a high voltage transmission line.

- The Valdez/Copper Basin regions are poised for economic development as evidenced by construction of the Princess Hotel near Copper Center and the new National Park Service visitor center both of which are scheduled to open in mid 2002. These projects, coupled with the strategic transportation corridors along the Glenn, Richardson, Alaska and Marine highways are all indicators the region has tremendous potential for future economic growth.
- Copper Valley Electric Association is excited about the future of the region and our ability to deliver cost effective energy solutions to fuel future prosperity. A gas project through Glennallen to Valdez, capable of serving west coast and world markets, not to mention the 800 miles between the North Slope and tidewater would be a major cornerstone in developing a sustainable economy for the State of Alaska at a critical time when timber, fishing and even the oil industry are in decline. In addition, a spur line to Anchorage along the Glenn Highway would augment declining gas reserves in the Cook Inlet region.
- I'd like to close on a personal note. I am a 42 year resident of the Great Land. When I moved to Anchorage with my family in 1959 Alaska's largest city had less than 20,000 residents. I remember the bumper sticker "I drove Tudor road and survived." Since that time the State has benefited from tremendous growth and prosperity however I am uncertain of how bright the future is, particularly if our resources are extracted to benefit others. Alaska's resources should be developed to benefit Alaskans. Developing a gas project aimed at maximizing corporate profits while ignoring sustainable, long term economic prosperity for Alaskan residents makes little sense to me. As the Council completes its very important work I urge you to carefully consider what is in the State's long term best financial interests and the interests of 630,000 Alaskans who are proud to call the Last Frontier home. I urge you to support the Alaska Gas Line Port Authority in developing a gas line project which ensures long term prosperity and a bright economic future for Alaska.
- Thank you

THOMAS R MARSHALL JR
1569 BIRCHWOOD ST
ANCHORAGE ALASKA 99508
U.S.A.

September 4, 200

Mr. Ken Freeman
Natural Gas coordinator
State of Alaska

Ken,
Here's a copy of the requested "notes on the length of time North Slope gas reserves will fill a gas sales line at a 4 BCF/D rate.

An arithmetic error was made in the governor's statement at last Thursday's RDC noon luncheon that 35 TCF proven reserves could fill the pipe line for 30 years at a 4BCF/D rate. It could fill the line for 24 years.

i.e. 4 BCF/D × 365 Days/Year = 1.460 TCF/Y

35 TCF ÷ 1.460 = 23.97 yrs.

However, there are not 35 TCF of booked proven reserves on the North Slope. There are 30.93 TCF including 5 TCF undeveloped reserves in the Pt. Thomp area. Reference P.12 Year 2000 annual report STATE Division of O.I + Gas.

30.93 TCF would fill the pipeline at a 4 BCF rate for 30.93 ÷ 1.46 TCF/Y = 21.2 years

However, all the above reserve figures do not include lease fuel gas deductions including fuel gas sold to gas deficient fields or estimated gas line transmission fuel

$\frac{1}{3}$ TCF x 30 years = 10TC

and estimated fuel requirements to hot water flood or steam flood the 30 to 40 billion barrels in place of heavy oil and bitumen at Ugnu and West Sak oil fields, should that prove feasible.

$\frac{1}{6}$ TCF x 30 years = 5 TC

Total estimated fuel gas needs 15TC

Recap: North Slope proven reserves 31 TCF
Total estimated fuel gas - 15TCF
North Slope gas available for pipeline 16 TCF

16 TCF ÷ 1.46 TCF/yr = 10.96 years

Conclusion:
North Slope natural gas reserves minus Total estimated fuel gas needs would fill a sales gas pipeline at a 4BCF/D rate for 10.96 years.

these figures are intended to demonstrate the need for more exploration on the North Slope including the 102 area of ANWR.
Also disappointments may be avoided down the road when the bankers put their pencil to risk financing for a pipeline.

Respectfully,
Thos. N. Marshall Jr.

c.c. Governor Tony Knowles
Mr. Robert Stiles - R.D.C.

SEP 14 2001

MON
9-10-01

Ken-59586 OFFICE OF THE GOVERNOR

Dear Tony Knowles,

I just want to get my two cents worth in about the new pipeline going through Canada.

We have many dear Canadian friends but going through the Government we have had problems constantly with the Canadians. Over the Salmon deadlock. We have traveled many times going through Canada and have had trouble on 3 occasions. Now going through the boarder inspects tobacco; guns, liquor and whatever their next items they want to regulate.

So if the Canadians get a big someplace they could shut the line down or jack up the price of going their part of the line. I just

do not treat their Government.
So please reconsider not
going through Canada and
seek other options.

Thank You
Lorraine Sonnabend



Ms. Lorraine Sonnaband
655 Holiday Dr.
Wasilla, AK 99654

I have no word processer.

Mandy Garnand
P.O. Box 11-1143
Anchorage, AK 99511-1143

Ken-57887

Re: Gas Line Development
Gov. Knowles
P.O. Box 110001
Juneau, AK 99811-0001

Dear Gov. Knowles:

I am an Alaskan citizen of 16 years, and have been doing a pretty substantial amount of researching on the effect ~~of~~ the carrying out of the gas line construction will have on our economy, environment, and community. I am writing to you today because I would like to ~~show~~ give you some information you cannot aquire from research papers, debates, or polls. I would like to offer you, and would be honored if you would accept, my personal feelings and opinions on the

much of an environmentalist, but pertaining to this issue I would not oblige to being referred to as so. Nature is one big network of chain reaction and events happening for reason. When men interfere w/ this cycle, the outcome is often a severity. There are so many environmental issues surrounding this proposal that I see the construction as playing w/ fire. We do not fully understand the balance of nature, therefore we have no business stepping in and interfearing, not knowing what the outcome will be. In the end, the land is what provides us, and w/out it we could not survive. Therefore; it should be our main concern. The key is balance and sacrifice. Sometimes money must be sacrificed to do the right thing, the safest and most secure for our future generations - my generation.

Mandy Garneau

subject matter.

As a member of the younger generation of our state and country, I have developed a great concern for the future of our States well-being. I have read about many environmental issues as well as economical, many political as well as social, and have learned a number of things. I realize our country may be facing a shortage of natural gas and that a gas line would really lead our economy to flourish. I also know that there are several environmental issues we face, some seemingly harmless to some that we ~~fear~~ detrimental. I have taken all of this into consideration and have come to one final conclusion.

My concluding thoughts on the issue are this: ~~we need to do~~ the land we live on is most important. I have never been

Ken-57888

Erika Brandner, 1200 Airport Heights
June 1, 2001
Re: Gas Line Development
Governor Knowles
P.O. Box 110001
Juneau, Alaska 99811-0001

Dear Governor Knowles:

As you are well aware, the opening of ANWR is a hot topic, at present. This ongoing debate stems from a more generalized, larger scale debate, however, and concerns none other than the implementation of a natural gas line in the North Slope Borough of Alaska. The economic benefits that would ultimately spring from the implementation of a natural gas pipeline in the North Slope Borough are enormous. Presently, Alaska contains the largest oil and gas reserves of any state in the U.S. Oil has been flowing through TAPS for over 20 years. The natural gas on the North Slope, amounting to approximately 30 trillion cubic feet, has never been commercially tapped. Geologists project that this estimate may amount to a grand total of 100 cubic feet of natural gas reserves. With several companies vying to develop a master plan regarding the most viably economical means of marketing these reserves of gas, prospects for gas line construction appear promising within the next five years. In short, the most prominent benefits of a future gas line include a new source of revenue for the state of Alaska, the creation of jobs both in Alaska and nationwide, the opportunity for employment, lower energy costs, and other indirect and longer term benefits for the aboriginal peoples and local communities of Alaska, the availability of natural gas to municipalities, and, lastly, the opportunity for Alaska to partake in the relief of the exponentially growing demand for natural gas by the world market.

The proposed routes for a multibillion-dollar natural gas pipeline from the North Slope include the shorter, cheaper Mackenzie River Valley route through Canada's Northwest Territory versus the Alaska Highway route, which would route the gas to Fairbanks and smaller Alaskan communities that rely on coal and heating oil. Although the Northern route would indubitably be more cost efficient and could result in higher wellhead values on the North Slope, such a route may result in a more unsatisfactory trade off as opposed to the Highway route, which is speculated to bring profound socioeconomic benefits to the state of Alaska. The companies that compose the North American Natural Gas Pipeline Group are currently spending $75 million to gauge whether or not a gas line is feasible (Joling, 2001). It currently appears that the costs of the Mackenzie River Valley route outweigh the benefits of the Highway proposal. In short, the proposed Highway route ensures that Alaskans will have access to enough natural gas to meet in-state demands, allow for in-state distribution for residential and commercial use, open the door to manufacturing value-added natural gas products, such as fertilizer, provide jobs during construction, operation, and maintenance phases and through support services, and, ultimately, the route would add an immense long-term property value to state and local governments. In addition, as you yourself have mentioned, the permits for this route are already in place and the plan is covered by a bilateral agreement between Canada and the U.S.

The multiplier effect of billions of dollars of investment within Alaska's borders would prove immense with the construction of the Alaska Highway pipeline. For example, state revenues of billions of dollars, access by communities to an affordable clean energy source, spin-off industries from gas liquids utilization, and the economies for the LNG and GTL projects would be born out of pipeline construction. All these amount to a staggering list of economic benefits and opportunities if the gas line follows the Highway route. Indeed, not only would a future gas line encompass a new source of revenue for Alaska and natural gas that would be used to supply small, Native communities such as the NSB, but job opportunities for indigenous Alaskans, Canadians, and individuals worldwide would benefit and Alaska would have the opportunity to partake in a large percentage of the supply of natural gas to demanding markets, especially that of the Asian market. In short, the cons of constructing a gas line through the NSB are far surpassed by the potential economic benefits of implementing a natural gas line, under the Highway route, from the NSB to smaller communities across Alaska.

Sincerely,

Erika Brandner

Erika Brandner

Ken-57886

Amanda Jorgenson
721 Bounty Dr.
Anchorage, AK 99515

June 3, 2001

Re: Gas Line Development

Governor Knowles
P.O. Box 110001
Juneau, AK 99811-0001

Governor Knowles,

During the last several months it has been brought out that you wish to continue the gas pipeline, which was an idea back in the 1970's that was discontinued because of high costs. I was wondering how this pipeline could benefit Alaska and the United States, other for the thirst of America's natural resources.

I am environmentally active and fail to understand the point of the construction of this pipeline. The construction the first time, in the 70's, was billions of dollars. The bloated carcass of the potentially largest and costliest privately financed construction project in history was reluctantly laid to rest. Did the shelf that this abandoned idea came from happen to land on your shelf? It is said that history repeats itself if one does not learn from it...is that where we are headed? If we, Alaska, end up continuing the construction of this gas pipeline, how much would we need to spend, how much of our money will go towards this? I can understand certain points of drilling and the constructing of pipelines, but why can we not save our most needed resources for when America is in dire need of it? Unless we need it right now, just to make gas prices go down. Perhaps there are other reasons that I have failed to acknowledge but that is all I have heard from the Bush Administration. If I could possibly be enlightened with the answers, I could possibly change my viewpoint of this situation.

I thank you for your time to read this letter. I hope to understand America's need to get all of our resources at this exact time. My opinions may be bias, but that is why I chose to write, to be enlightened. I thank you again.

Sincerely,

Amanda Jorgenson

Subject: suggestion
Date: Wed, 11 Jul 2001 22:00:18 -0800
From: Norma Roehl <jjroehl@gci.net>
To: gasline@gov.state.ak.us

Greetings:
I would like to make a suggestion concerning the natural gas route from the North Slope. Maybe the route I'm thinking would cost considerably less than going the Beaufort Sea/Canadian route.
My friend & I attended a meeting in June & she had an Alaskan map, -I looked at the area & wrote the trails down, so here is the route. The road used to be called the "Government Road", I don't know the exact date, possibly 1930 or 1940 and I don't know if the "Government Road" is the same as the following locations. Possibly the road is still there, and would need clearing.

This is the Title on the map:

RS 2477 Project
Hsitoric Transportation Routes
July, 1995

Trail Names
254: Wiseman-Chandelar
27: Beaver-Caro
189: Snowshoe-Beaver

Pipeline to trail 254 going to #27 trail from Beaver to trail 189. Connecting to existing road between Livengood & Fairbanks.

Fairbanks to 480 - Little Gerstle River - Sheep Creek towards Northway Junction.

Thank you and please let me know the decision concerning this route.

Norma J. Roehl
P.O. Box 3757
Palmer, AK 99645

E-mail: jjroehl@gci.net

Dear Gov. Knowles: In the news media I often see your and seemingly just about everyone else's support for a pipeline out of the state or within the state to ship out of the state. I'm not for or against that although it serves certain interests not the state as a whole. I used to live in Sterling and the pipeline to Anchorage ran the whole length of our ten acre property. We could not tap into it even with 5 other families willing to join us. We contacted the company that owned the pipeline and they said a tap to so few people was not cost effective. People whe lived in the right-of-way before the line was put in did get a tap because they made it a condition of access. Before and after living in Sterling we have lived in Bethel for 20+ years. As with most of Western Alaska, (With the exception of Barrow that I know of.), we have no "natural gas" access. We are probably a small % of the states population but are stuck in high cost area and cannot look forward to economic developement on any reasonable scale as long as costs are so high. Access to natural gas would do a lot to change that for future generations. The average cost of utilities in Barrow is about 1/2 of what they are in Bethel and the surrounding area. I know it would not be cost effective for the oil companies but it would be of tremendous benifit to the people of this area.

Sincerely,
Leonard Revet lrevet@unicom-alaska.com

Subject: [Fwd: GTL'S vs. TAGS]
Date: Thu, 11 Oct 2001 13:45:19 -0800
From: Debra Ceffalio <Debra_Ceffalio@gov.state.ak.us>
Organization: Alaska Office of the Governor
To: Erika B Mcconnell <erika_mcconnell@gov.state.ak.us>, Kenneth J Freeman <ken_freeman@gov.state.ak.us>

fyi

govmail wrote:

> *Thank you for writing to Governor Tony Knowles. I have routed your*
> *message to the appropriate person in the Office of the Governor who*
> *is most knowledgeable about this issue. Your ideas, concerns, and*
> *recommendations are valuable to us, and we appreciate that you have*
> *taken the time to write. Again, thank you.*
>
> *Mike Thomas wrote:*
>
> > *Date: 10/9/2001*
> > *Response: checkbox*
> > *Email: poc@gci.net*
> > *Name: Mike Thomas*
> > *Address: 310 K Street, Suite 200*
> > *City: Anchorage*
> > *State: AK*
> > *Zip Code: 99501*
> > *Subject: GTL'S vs. TAGS*
> > *Message: Dear Governor Knowles:*
> >
> > *I am writing to implore you to take the lead on*
> > *developing Alaska's resources. A gas pipeline*
> > *is not the answer, and likely won't ever be.*
> > *The sooner we realize that the better off we*
> > *will be.*
> >
> > *GTL's are the answer. The capital expenditure*
> > *is significantly less, and the return much, much*
> > *higher. It is a technology that can be put in*
> > *place now.*
> >
> > *Please take a moment and go to www.angtl.com.*
> > *Please then take the lead in getting support for*
> > *the development of this industry here in*
> > *Alaska. We arein danger of squandering the*
> > *opportunity to encourage investment in Alaska*
> > *for this technology and wasting even more*
> > *natural gas.*
> >
> > *Thanks,*
> >
> > *Mike Thomas*

--
Debra Ceffalio
AK Highway Natural Gas Policy Council
Office of the Governor
phone 907.269.0345 - fax 907.269.0349
www.gov.state.ak.us/gascouncil

Subject: Gas Pipline
Date: Wed, 03 Oct 2001 08:48:38 -0800
From: cvedc <cvedc@alaska.net>
To: gasline@gov.state.ak.us

Sir; We here in the Copper Valley belie /e that anything less than the Port Authority Project would hurt all of Alaska! For once please consider Alaska first and do not bow to the oil companies wishes. With the port Authority project you can build a pipeline to the south 48 and do for all Alaska too. Thank you for your time.
Sincerely, John Downes, CVEDC

Foothills Pipe Lines Ltd.
Information Brief

Routing Comparison of the Alaska Highway Pipeline and the Over-the-Top Project

Introduction

This brief discusses the relative complexities of installing a natural gas pipeline along two different routes from the North Slope in Alaska to a common receipt point at Gordondale, Alberta. The two routes are the already-sanctioned Alaska Highway Pipeline Project (AHPP) and the Over-the-Top/Mackenzie Valley Project (OTT). **Figure 1 Northern Pipeline Routing Options** shows the locations of the two routes. **Figure 2 Comparison of Key Statistics** summarizes key statistics for the two routes including length, terrain and construction parameters.

From the map and summary, as well as an examination of physical relief (**Figure 3 Northern Terrain Relief Map**), it is apparent that the AHPP encounters more mountainous terrain, river crossings, and rock. However, it is insufficient to compare the routes solely on these characteristics because many features that are more challenging than mountains and rivers characterize the northern terrain and influence the project configuration and cost. These would include factors such as transportation access and climate. There are other conditions that both routes face in common, for example permafrost as shown in **Figure 4 Northern Terrain – Extent of Permafrost**.

The brief includes additional comparative figures and tables to facilitate the discussion of variables that impact routing, construction, and timing. When the ultimate measures of capital cost and on stream date are considered, the AHPP emerges as a preferred route by a significant margin.

Terrain

(a) Physical Features

The AHPP route traverses approximately 400 kilometers of mountainous terrain and 35 major river crossings. The presence of mountainous terrain and river crossings does not constitute "route stoppers" for the AHPP. Pipeline technology involving rock blasting and ditch rock has been widely employed in mountainous terrain throughout the world, including British Columbia. None of these conditions of terrain along the AHPP present any challenge to the limits of present-day technology, except perhaps to provide an opportunity to perfect more efficient and cost-effective techniques.

The OTT route is characterized by an offshore crossing through the Beaufort Sea of about 500 kilometers or over 20% of the route. To understand the formidable challenge of this routing segment it is important to understand the physical setting as shown in **Figure 5 Over-the-Top Marine Routing Alternatives**. For analytical purposes, the sea bottom adjacent to the shore can be subdivided into three zones: foreshore, nearshore, and

offshore. Each of these has separate characteristics and limitations. Our investigation of these limitations, as discussed in a following section, suggests that the most feasible location for a submersed pipeline would be in the offshore zone up to 60 kilometers from shore and in water depths up to 60 meters.

Offshore pipeline technology has been successfully employed at much greater depths throughout the world. However, little experience is available to draw on related to possible installation in the foreshore and nearshore zones of the Beaufort Sea where risks exist due to extension of permafrost and ice scour that is known to occur in this region. The risk of ice scour that is caused by ice grounding on the seabed requires that pipelines be buried with sufficient cover to avoid being damaged. These risks confine the underwater segment to the offshore zone. However, in this zone pack ice conditions make it difficult to locate compressor stations; this is a major limiting factor on design throughput and pipe sizing. The resulting need for larger diameter pipe and operating pressure up to 3000 psi to achieve higher flow rates poses further challenges both to the limits of pipe metallurgy and offshore pipeline technology. Thus, at a design pressure of 2,050 psi, dual lines are required for crossing the Beaufort Sea.

The offshore and land portions of the OTT dictate that different types of equipment and crews be utilized for construction. The offshore portion will likely involve the development of special-purpose equipment (such as off-shore lay barges) that may be employed just once. Unless the equipment can be utilized elsewhere, the project capital may have to absorb the full cost of this equipment. A further implication of the offshore terrain will be the need to develop special-purpose equipment to conduct maintenance and repair for the operations phase of the project.

The impact of terrain is reflected directly in the unit cost of pipeline installation. The cost increases with increasing complexity of terrain. Typically the cost is measured in diameter-inch-miles. The cost of installing a high-pressure pipeline in mountainous rocky terrain is estimated to be $25,000 per diameter-inch-mile. The following table compares the cost of installing pipelines in various terrains. The costs shown are inclusive of logistics costs.

Comparative Cost of Pipeline Construction

Terrain	Cost per diameter-inch-mile[1] in $US
Prairie (recent)	10,300
Prairie (Alliance Pipeline US)	13,400
Mountain – Rock (recent)	25,000
Permafrost (estimate)	34,800
OTT Offshore (estimate)	73,200

1. Adjusted for equivalent wall thickness and pressure

(b) Impact on Construction Timing

The terrain also dictates when actual construction installation of the pipeline can occur. The AHPP route can be constructed utilizing a combination of 40% summer and 60%

winter construction. While the terrain varies along the route, more continuous access gives the construction schedule the advantage of ample flexibility to maximize the utilization of crews and equipment along winter and summer sections with minimal downtime between seasons.

Along the OTT route the offshore and onshore segments have much different construction seasons. In the offshore zone construction is limited to a very narrow construction period when open water operations can be conducted in the Beaufort Sea. Historically there is a 50% probability of a 40-day open water period and a 15% probability of a 60-day period. For the remainder of the year, ice conditions in the offshore zone are unstable and unusable as a suitable platform from which to lay pipe. Permafrost and wet areas dominate the onshore portion. These considerations require that construction be conducted when the ground is frozen during the winter months between December and mid-April. Therefore, overall construction access for the OTT route will cause significant downtime between seasons, with a corresponding increase in construction time and cost. In the worse case scenario of extreme weather, a short open water period or none at all, the risk exists of losing an entire construction season along the offshore segment.

Transportation Access

An important determinant for any major infrastructure project relates to logistics, specifically access to transportation for marshalling materials, equipment, workers, and supplies to construct and later operate the project. In fact, lack of adequate transportation has held back many projects in the North. **Figure 6 Regional Transportation Access** depicts regional transportation access for the routes. Much of the transportation infrastructure is seasonal in nature as illustrated in **Figure 7 Regional Transportation Access by Season**.

The AHPP enjoys favourable year-round access along its entire route. Along the initial northern stretch from Prudhoe Bay to Fairbanks it parallels the existing TransAlaska crude oil pipeline and the Dalton Highway. The remainder of the route parallels the Alaska Highway. Year-round transportation access is of major importance to the rapid installation of the AHPP, and the subsequent operations life.

The OTT is much less favourably situated with respect to transportation infrastructure. On the offshore portion of the route, icebreakers can be employed to extend the transportation season beyond the window of open water access in the Beaufort Sea. On the overland portion access is also seasonal. There is no all-weather road paralleling the route. Winter roads are a partial solution during winter months from December to mid-April. In the summer months from mid-June to mid-September the Mackenzie River has an established barge system that can be utilized. Even with this seasonal access, additional entry to the actual pipeline right-of-way will have still to be developed to facilitate construction. The poor transportation access will also make the operations phase more difficult.

Construction Schedule

Figure 8 Comparative Construction Schedule provides a comparison of the project schedules. The construction schedule for the projects is influenced by the combination of transportation access and seasonal construction periods. The main implications are in the mobilization stages and actual construction periods. Each mobilization requires a suitable break-in period until the crews achieve efficient productivity.

For the AHPP route, favourable year-round transportation accesses and summer construction windows combine to minimize the mobilization stage and construction period. The ratio of summer-to-winter construction helps to minimize downtime and remobilization costs. The actual construction can be completed in a period of less than 24 months.

The OTT route transportation access and seasonal construction restrictions impose major challenges. The mobilization effort is more difficult and extended. Three construction seasons are required to complete both the onshore and offshore segments. Between seasons crews and equipment are idled. The crews have to be re-mobilized three times. The equipment remains stranded for the summer, as it can not readily be deployed on another project. The actual elapse time for construction is over 30 months. The protracted construction period also means that capital is tied up for a significantly longer periods of time during which it is accruing interest with a resulting increase in the final unit cost of shipping gas on the system.

Economics

Foothills Pipe Lines and TransCanada Pipelines have compared the economics for the two routes as part of an assessment of several alternative pipeline routings for North Slope gas. The analysis involved a consideration of various environmental and technical risk factors. The assessment relied on data and investigation furnished from three outside consulting firms. The analysis grouped constraints into categories by critical, serious, and minor. **Figure 9 Routing Comparisons** is a graphical comparison of the incidence of critical and serious constraints for the various routes considered. The following table summarizes the numbers for the two routes included in this brief.

Number of Constraints by Pipeline Route

Constraint	Impact	AHPP	OTT/MVP
Critical	*Route Stopper*	0	7
Serious	*Cost Adder*	1	28

Figure 10 Over-the-Top Constraints provides a listing of the critical and serious constraints for the OTT. These constraints impact on the specific routing of an offshore line and development of the OTT project. It should be noted that the one serious constraint which AHPP faces is shared in common with the OTT, namely the state of Aboriginal Land Claim settlements in Canada.

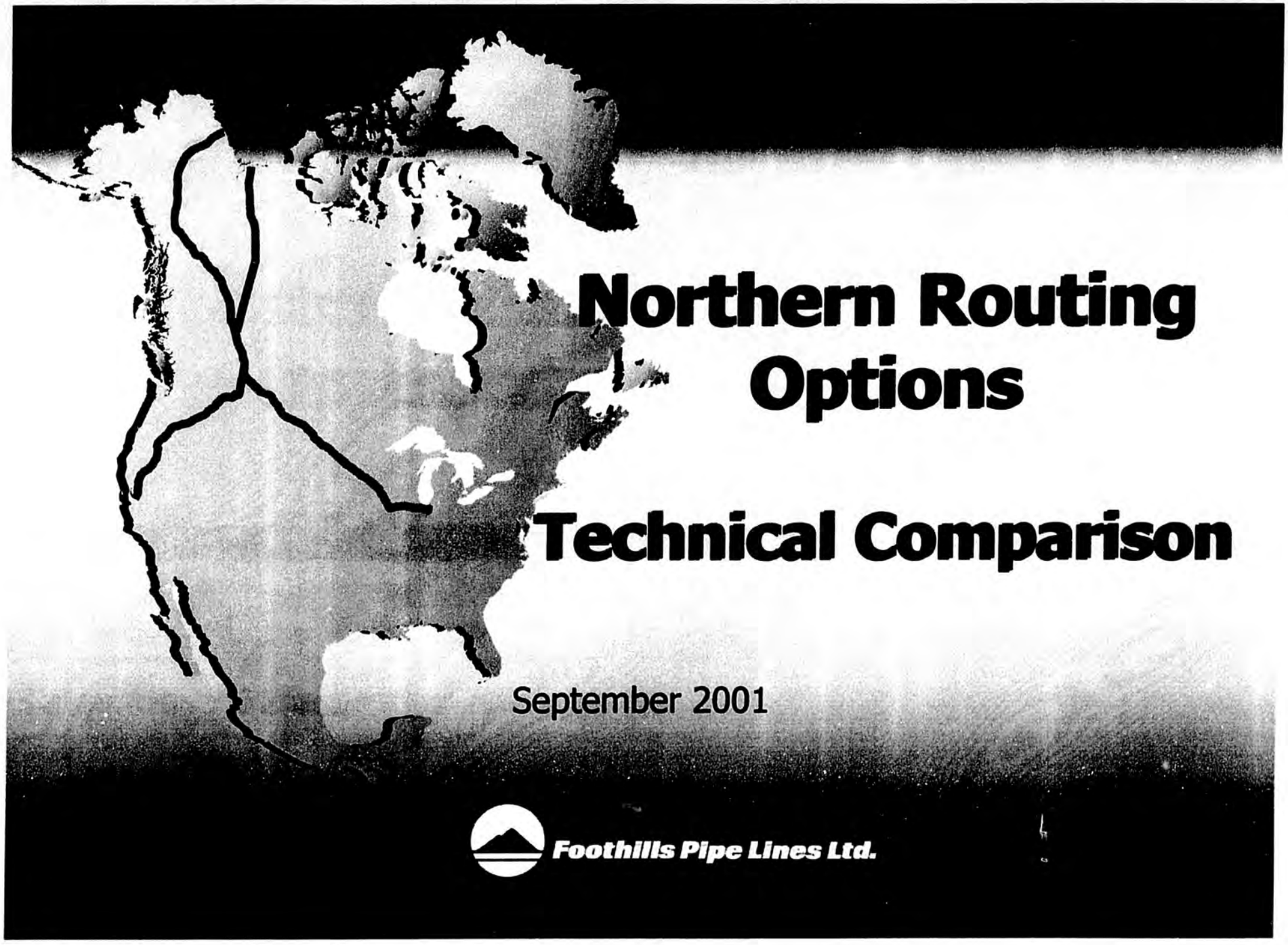
Foothills and TransCanada relied on this analysis to estimate the capital cost of the OTT for comparison with the AHPP. The capital cost build up included the environmental and technical factors as well as the comparison of terrain and access discussed earlier in the brief. In order to evaluate the two routes on a comparable basis, taking into account the functionality of the OTT route to capture throughput from the Mackenzie Delta, the analysis compares the OTT versus the two-pipeline option of separate AHPP and Mackenzie Delta pipelines.

Comparative Capital Cost by Pipeline Route

	AHPP and MVP two-line option	**OTT/MVP**
Throughput (Bcfd)		
North Slope	4.0	4.0
Mackenzie Delta	1.2	1.2
Years to Start-up	6-7 (AHPP) 8-9 (MVP)	9-10
Capital Cost ($Billion – US)	12.8	13.0

The analysis concluded that the capital cost of the two routes is nearly equivalent, after accounting for the degrees of uncertainty associated with both routes. The OTT has associated with it a greater degree of uncertainty and a much longer timeframe before the flow of first gas. The later start-up for the OTT is due in large part to the construction difficulty and partly to the Greenfield nature of the project. The AHPP enjoys a significant head start due to existing legislation and regulation.

It should also be noted that the capital cost estimates include components of interest during construction and escalation for inflation, both of which will be much more pronounced for the OTT due to its longer schedule. An extended schedule also defers the start date for flow of revenues to the various stakeholders. An assumed flow of 4.0 Bcfd at a price of $3.00 per MMbtu translates to annual revenues of $US 4.4 Billion. Stated in other terms, each month of delay postpones over $US 360 million of revenue flow.



Northern Routing Options

Technical Comparison

September 2001

Foothills Pipe Lines Ltd.

Figure 1

Northern Pipeline Routing Options

Prudhoe Bay to Gordondale

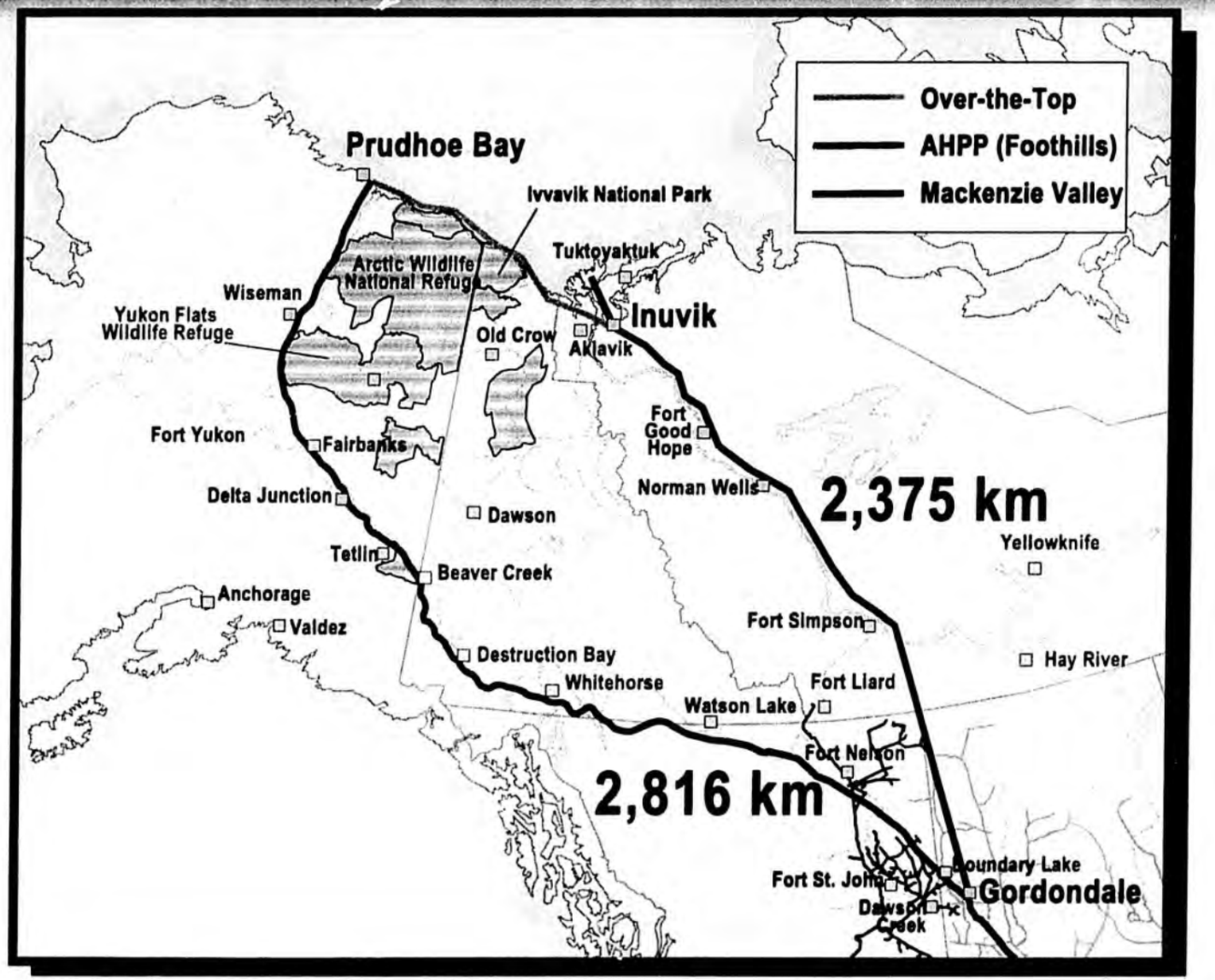


Figure 2

Comparison of Key Statistics ANGTS/Over-the-Top

Prudhoe Bay to Gordondale

	AHPP	OTT/Mackenzie Valley
Length (km)	2816	2375
Offshore (km)	0	500 (21%)
Major River Crossings	35	8
Ditch Rock (km)	419	96
Mountainous Terrain (km)	400	0
Winter Construction (km)	1694 (60%)	1875 All onshore (79%)
Summer Construction (km)	1122 (40%)	500 All offshore (21%)
Project Schedule (years)	6.5	10.5
Construction Schedule (years)	2	3
Road Access	Alaska Highway Dalton Highway	Liard Trail Mackenzie Highway (Winter Only) Dempster Highway Alaska Highway Dalton Highway
Ports	Prudhoe Bay (Seasonal) Skagway Valdez Whittier	Hay River (Barge - Seasonal) Prudhoe Bay (Seasonal)
Rail	Fort Nelson Fairbanks	Fort Nelson Hay River

Figure 3

Northern Terrain Relief Map

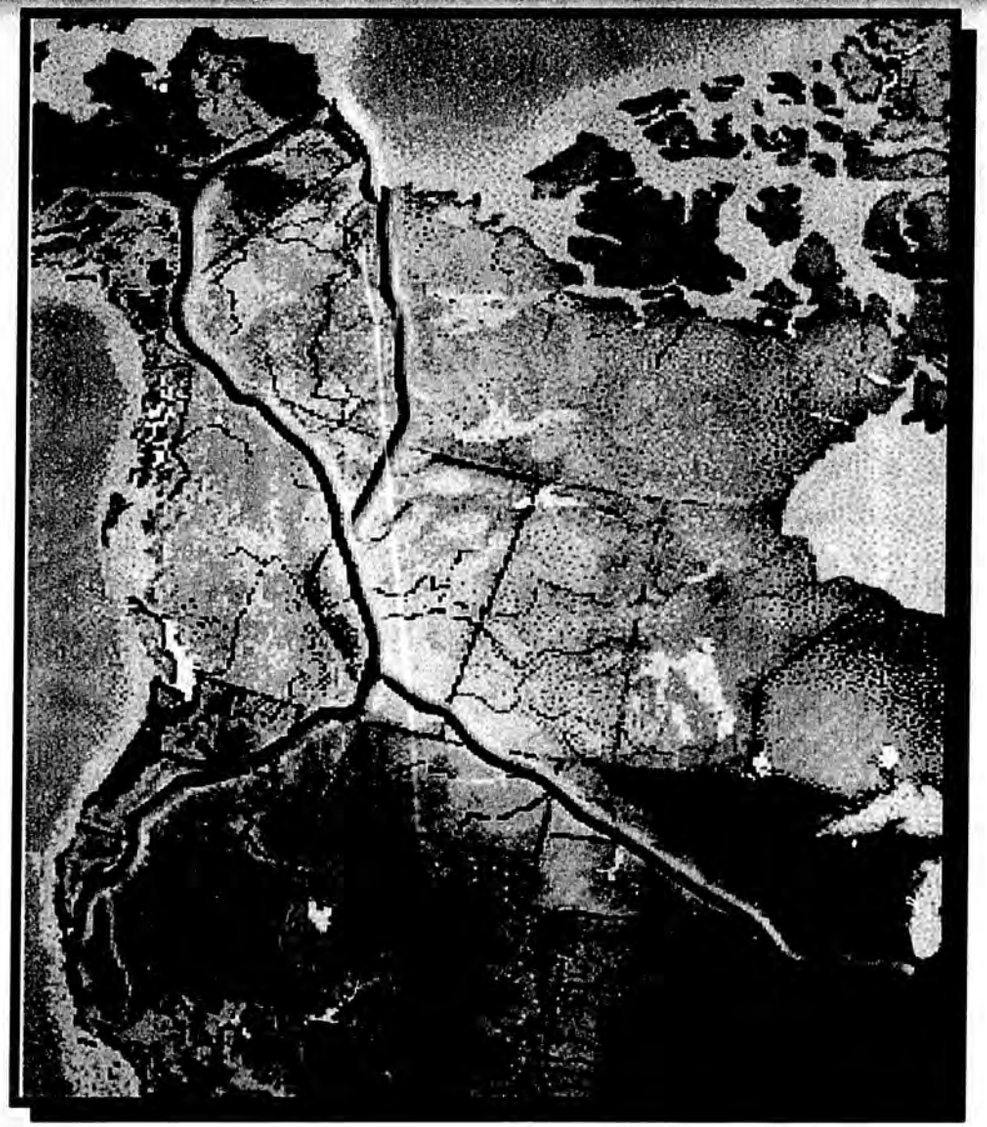


Figure 4

Northern Terrain - Extent of Permafrost

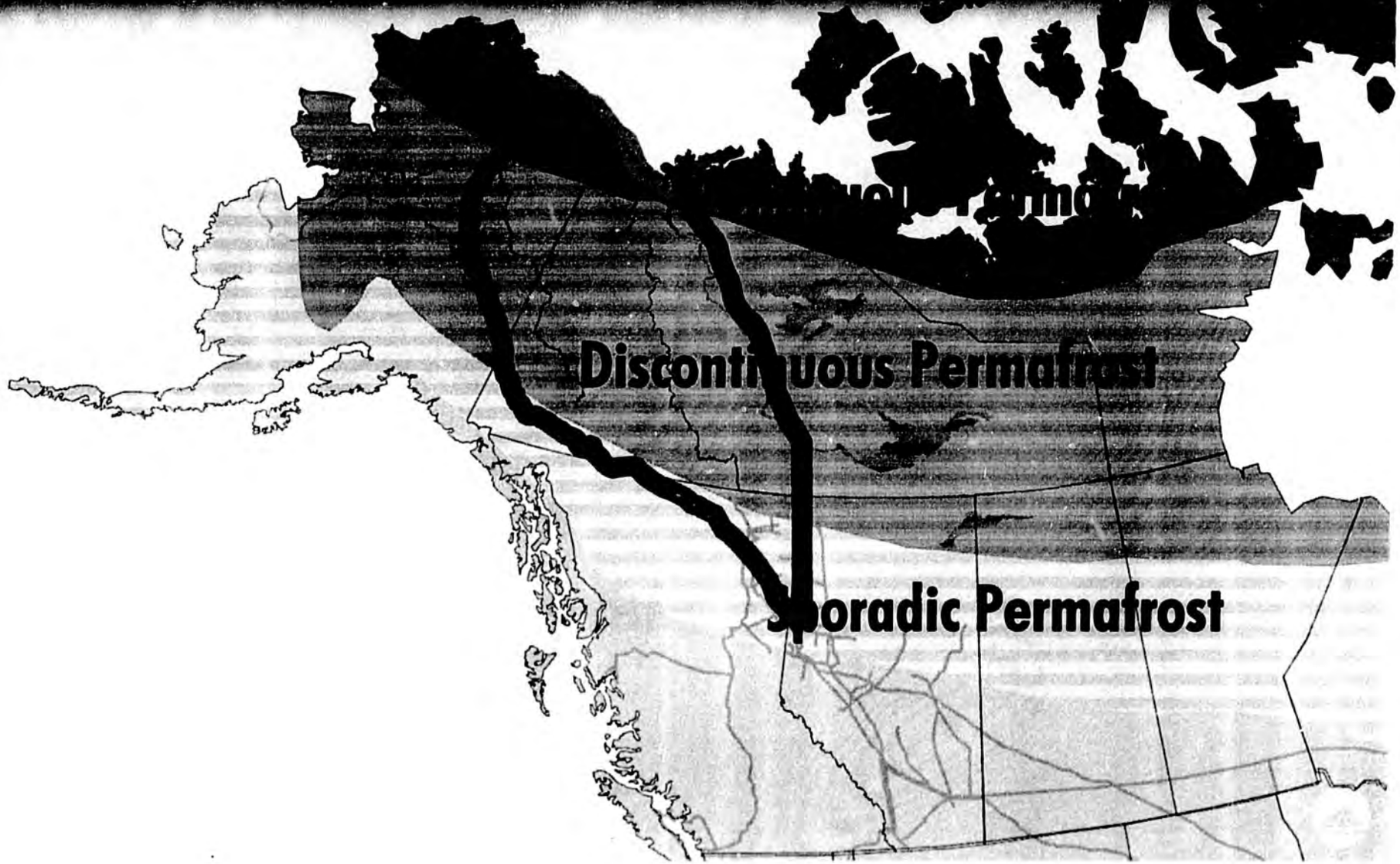


Figure 5

Over-the-Top Marine Routing Alternatives

- **Foreshore**
  - Tidal zone
  - Bottom fast ice (0-2 m depth, 0-2 km offshore)
- **Nearshore**
  - Floating land fast ice (2-10 m depth, 2 -10 km offshore)
- **Offshore**
  - Stamukhi zone (10 - 30 m depth, 5 - 25 km offshore)
  - Pack ice zone (>30 m depth, 25 - 50 km offshore - >60 m depth, 60+ km offshore)

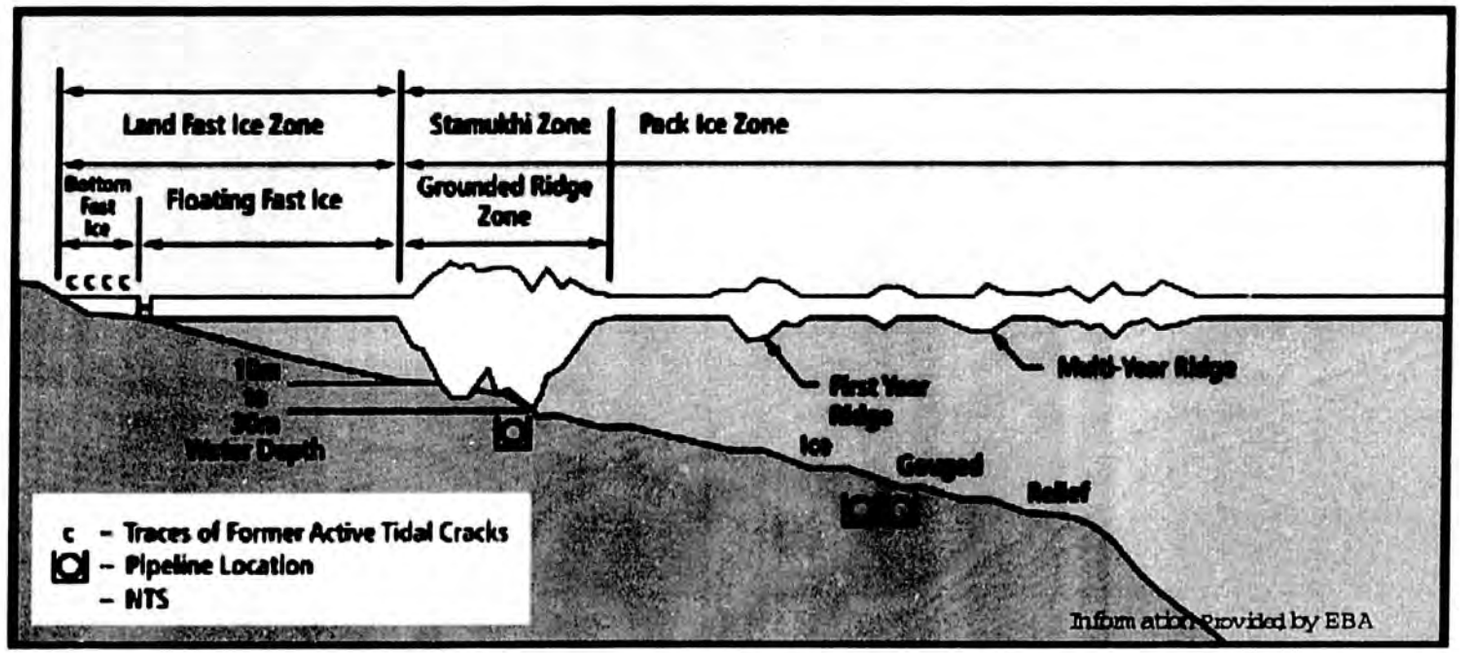


Figure 6

Regional Transportation Access

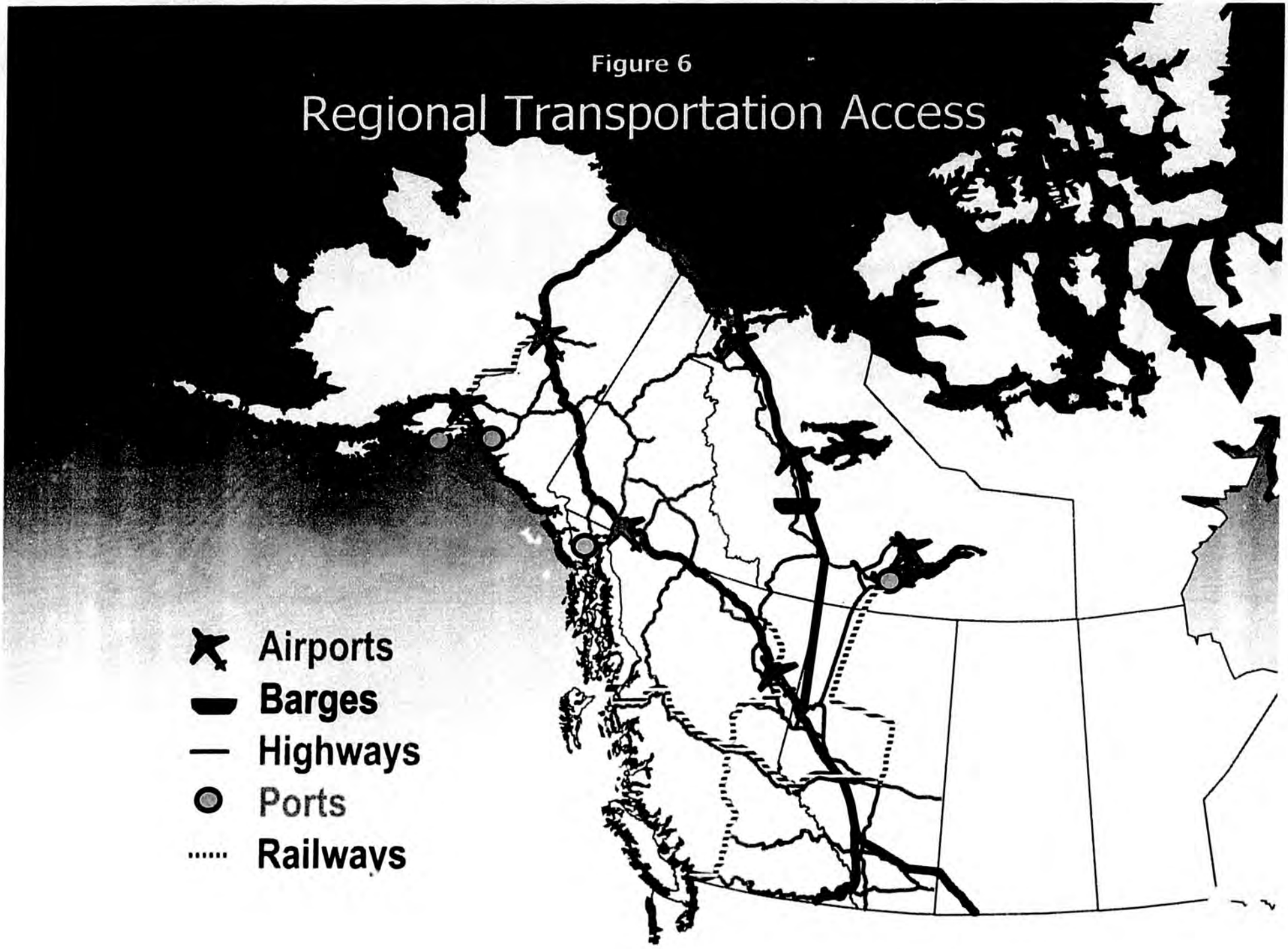


Figure 7

Regional Transportation Access by Season

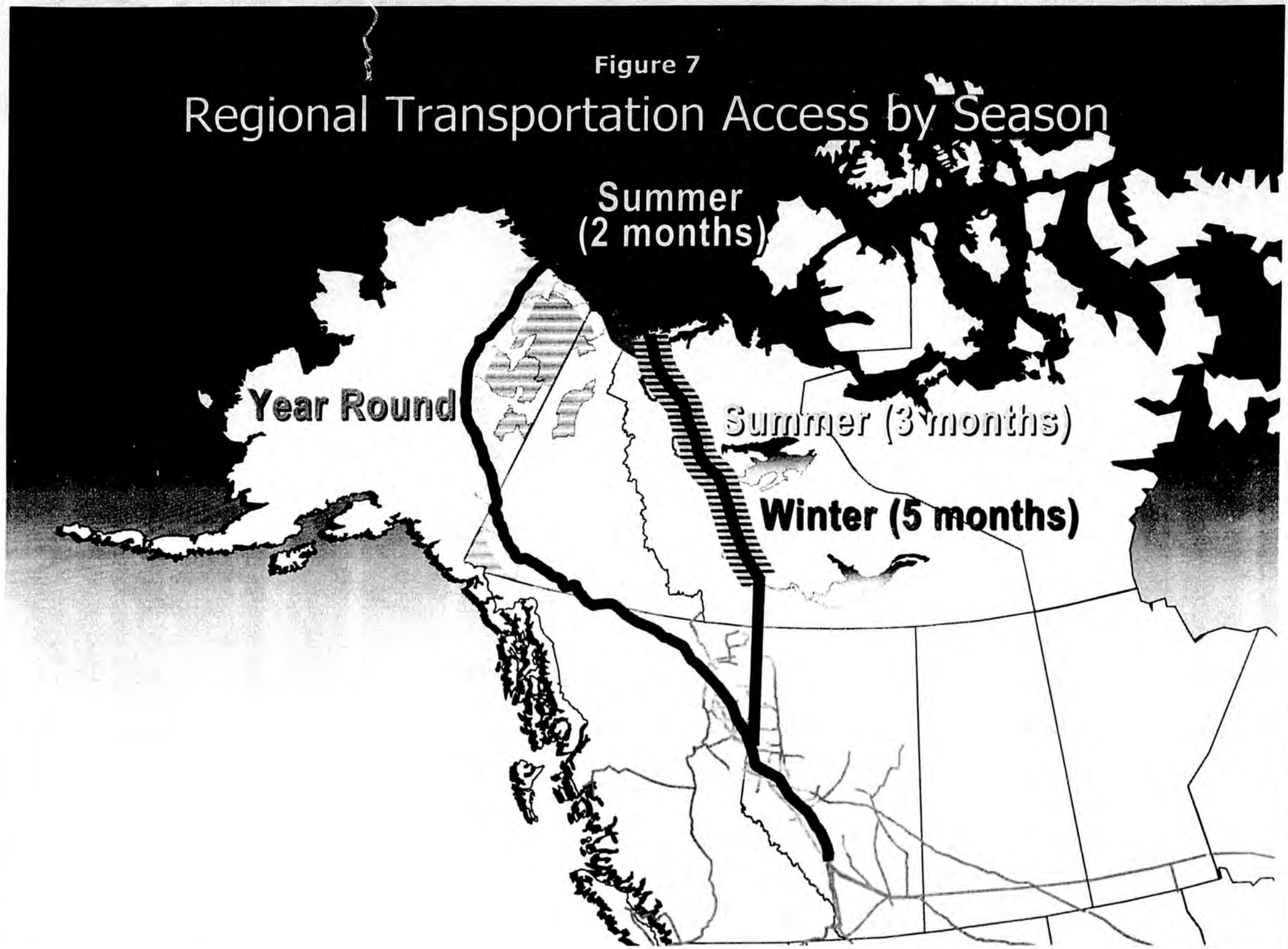


Figure 8

Northern Pipelines
Comparative Construction Schedule

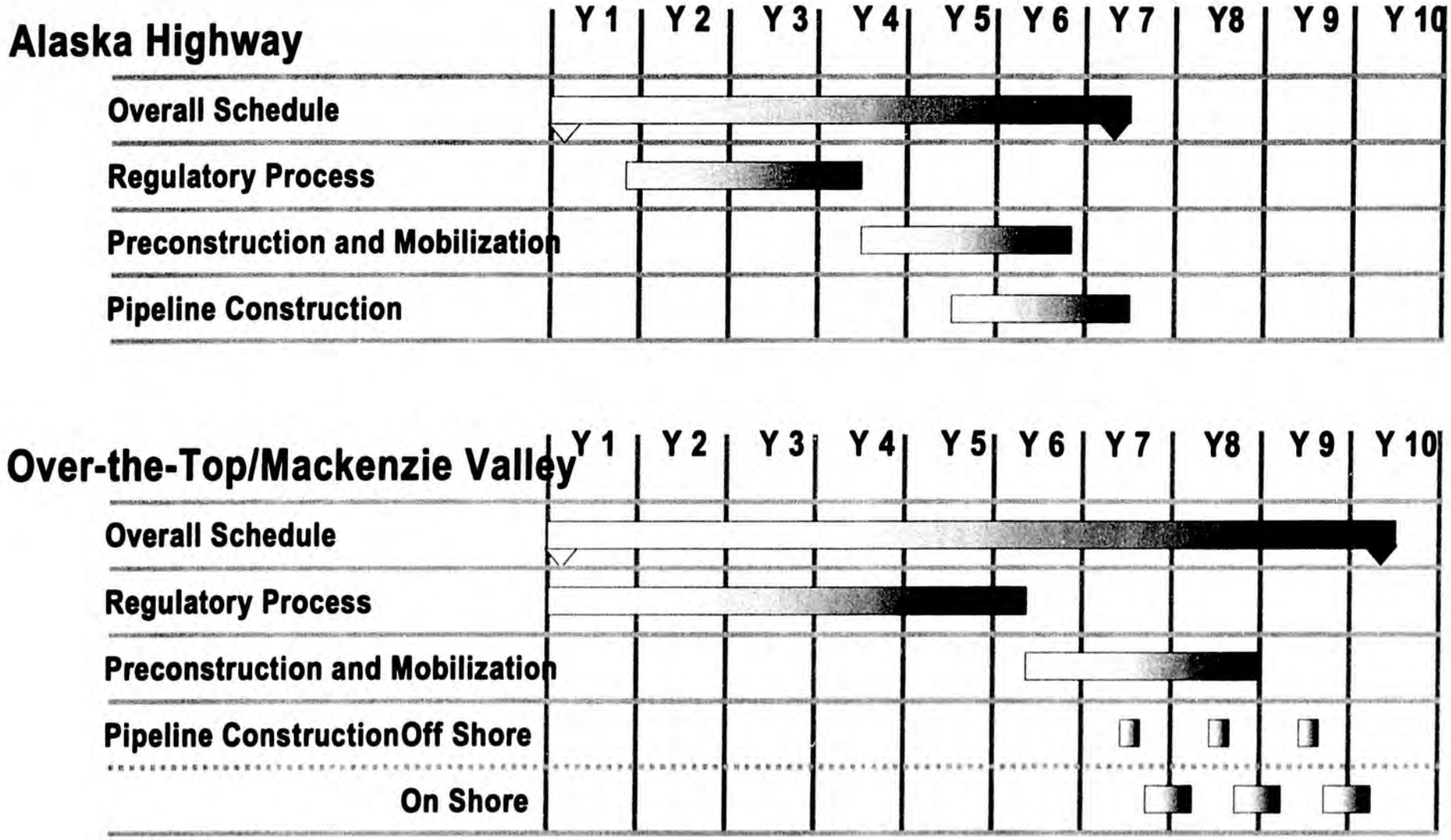
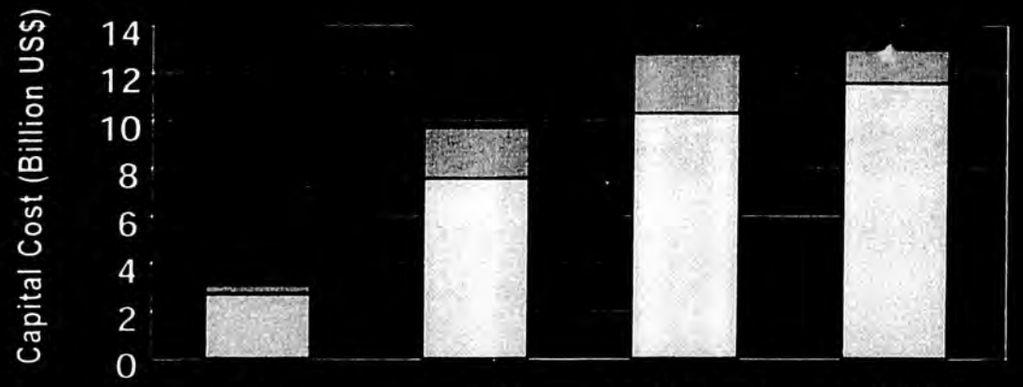


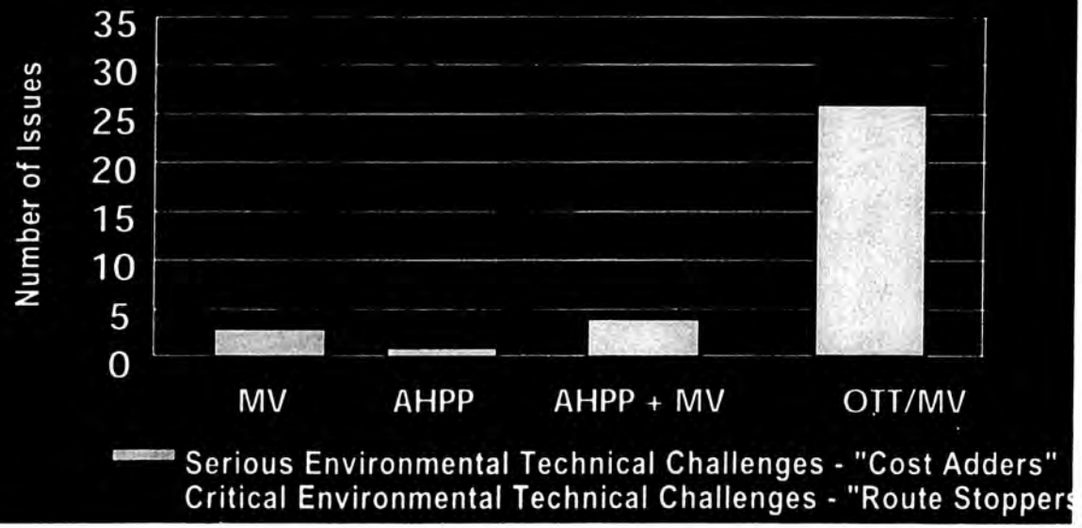
Figure 9

Routing Comparisons

Capital Cost



Risk Profile



MV - Mackenzie Valley
AHPP - Alaska
OTT - Over-the-Top (Prudhoe Bay/ Mackenzie Delta)

Figure 10

Over-the-Top Route Constraints - Environmental

Critical	Serious
• Environmental/Technical Challenges • **Route Stoppers**	• Route, timing, construction impacts • **Cost Adders**

Environmental	**Environmental**
1. State, Congressional, Presidential approvals for foreshore ANWR activity 2. Nesting Habitats on Barrier Islands (Alaska) on near shore route 3. No Development Zone: Ivvavik National Park (Yukon) 4. No Development Zone: nearshore Herschel Island Territorial Park	1. Prudhoe Bay Boulder Patch – arctic kelp 2. Barrier Islands – ringed seal and migratory birds 3. Herschel Island – bowhead whale, August feeding and September/October Alaskan hunt restriction 4. Mackenzie Estuary – beluga whale – zone 1 & 2 5. Eastern North Slope – management zone D ➢ Wildlife, fish, waterfowl constraints ➢ Preservation of traditional native use 6. Kendall Island Bird Sanctuary 7. Inuvialuit beluga whale hunt (June/July) 8. Polar bear dens, on-ice management 9. Evolving regulatory process could increase uncertainty 10. International boundary dispute/Jones Act 11. Evolving regulatory process could increase uncertainty 12. Detailed protection plans for protected areas 13. Unresolved land claims*

*Common with AHPP

Figure 10

Over-the-Top Route Constraints - Technical

Critical	Serious
• Environmental/Technical Challenges • **Route Stoppers**	• Route, timing, construction impacts • **Cost Adders**

Technical	**Technical**
1. Coastal erosion and storm surge for both foreshore and nearshore route 2. Camden Bay seismicity for offshore route 3. Barrier Islands migration for foreshore and nearshore routes	1. Stable ice platform 2. Ice scour and pipe depth 3. Ice ride-up and rubble fields 4. Strudel scour and river deltas 5. Shore permafrost 6. Landfall transitions 7. Restricted land access – winter 8. Restricted open ice window 9. Supply logistics 10. Accessibility for maintenance and operation 11. Trench backfill requirement (Northstar) 12. Leak monitoring requirement (Northstar) 13. Mackenzie trough 14. Gravity-based structures 15. Umbilical trenching



Foothills Pipe Lines

FAX TRANSMITTAL

file

STATE OF ALASKA
OFFICE OF THE GOVERNOR

TONY KNOWLES
GOVERNOR

FRAN ULMER
LIEUTENANT GOVERNOR

OFFICE OF THE GOVERNOR
PO BOX 110001
JUNEAU, AK 99811-0001

Telephone: (907) 465-3500
Fax: (907) 465-3532

Date: **September 12, 2001**

To: **Rick Halford** **Fax No.:** **694-0549**

Pages: **7**

From: **Tony Knowles**
Governor

If you received this FAX in error, please immediately notify the sender by telephone, and return this FAX to the sender at the above address. Thank you.

TONY KNOWLES
GOVERNOR

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

September 12, 2001

Dear Rick,

Thanks for all of your efforts in moving the gas project forward. They have been essential to our progress so far. I especially appreciate the meeting we had at my Anchorage office prior to your public meeting in Valdez where we discussed the state's draft legislation in response to the proposed legislation authored by the producers. I incorporated our discussion into the "10 point" plan I presented to the Resource Development Council and then sent to Senators Murkowski and Bingaman. I have enclosed a copy of that letter to you.

We are in the process of developing final legislative recommendations and I would appreciate your comments on any additions, subtractions, or modifications. If you could send those to Charlie Cole, the subcommittee chair of federal legislation, we will try to incorporate them into the final draft recommendations. This will be sent back to all Policy Committee members, producers, and pipeline companies for comment prior to presentation to the State Joint Pipeline Committee and then to Senator Murkowski and Senator Bingaman.

Sincerely,

Tony Knowles
Governor

Enclosure

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September 10, 2001

The Honorable Frank Murkowski
United State Senator, Alaska
322 Senate Hart Office Building
Washington, DC 20510-0202

Frank

Dear Senator Murkowski:

I write on a subject of pressing national and state interest, the need to facilitate a natural gas pipeline from Alaska to the lower 48 states. The Alaska Highway natural gas pipeline would be America's largest privately funded construction project, requiring an investment of as much as $20 billion. With the national economy sagging, this single project would be an enormous shot in the arm to America's industry and workforce like nothing else on the horizon, creating thousands of good-paying, long-term jobs across our country.

If built, it would deliver approximately 35 trillion cubic feet of ready-for-market Alaska North Slope natural gas. It also would open the way for the exploration and development of an additional 100 trillion cubic feet of natural gas that other fields in Alaska may hold. In the 1970s, federal legislation was needed to clear the way for the fast and successful development of the Trans-Alaska Pipeline System (TAPS). Similarly, legislation now is needed to clear the way for an Alaska gas pipeline. What follows is a summary of the benefits to our nation and to Alaska from the Alaska Highway pipeline project and a description of the essential provisions of legislation that would enable its construction.

Today, natural gas plays an increasingly prominent role in our nation's energy supply and is the fuel of choice for the rapidly expanding U.S. electricity generation market. Rising consumer demand, national security concerns, environmental needs, and economic competitiveness require that we continue to find new sources of natural gas in North America. With Alaska's known reserves representing more than 20 percent of the United States' natural gas reserve base, Alaska's North Slope gas can provide much of the needed new domestic source of environmentally clean energy.

Building the Alaska Highway gas pipeline will also help stabilize and increase our nation's economic growth at a time when our economy is suffering. A project of this size

will positively impact the nation's as well as Alaska's economy. Construction alone will rejuvenate the U.S. steel industry and provide jobs to thousands of Americans, including many Alaskans. It is expected that the Alaska portion of the pipeline project alone will require some 1.5 million tons of steel, with related costs from manufacturing to delivery estimated at $900 per ton, producing about 2,000 steel industry jobs. Keeping that substantial amount of money in North America cannot help but benefit each country's economy.

Many jobs will still be required once the project becomes operational, resulting in economic benefits in the form of wages, federal and state taxes, royalties, and other revenues. Further, the availability of gas in the lower 48 and in Alaska can be expected to generate substantial new investment and employment. Economists tell us that such a project could have an economic multiplier effect of 4-6, that is, for every $1 spent on the project, $4-6 of money flow is stimulated throughout other sections of the economy. Conservative projections are that this project will generate 160,000 jobs over the life of the project and contribute $300 billion to America's Gross Domestic Product.

To best achieve these national interests we need to have federal legislation, just as we did for TAPS, that brings these reserves to market in Alaska and the lower 48 states, and to do so as quickly as possible. We need to incorporate provisions that show a preference for American industry and American jobs. And we need to prepare for the future by allowing access of all natural gas developers to the pipeline. But Alaska also must benefit from delivery of North Slope gas to the U.S. market. We need federal legislation that would allow for the utilization and transportation of natural gas use for the benefit of Alaskans and that provides a preference for local hire, local businesses, and Alaska Natives.

Earlier this year I formed the Alaska Highway Natural Gas Policy Council, which held hearings across Alaska in order to solicit the views of Alaskans on the many complicated issues surrounding North Slope gas development and transportation. The council received many useful and thoughtful suggestions from various interested parties. It is fair to say a consensus exists among Alaska businesses, Alaska Natives, organized labor, environmental and civic groups and the Alaska Legislature that the following principles should be embodied in any new federal legislation authorizing and encouraging the construction of the Alaska portion of the Alaska Natural Gas Transportation System (ANGTS).

1. Deliver Alaska Natural Gas to the Lower 48 States as Quickly and Safely as Possible

- Alaska Highway Route. Any legislation should reiterate that the Alaska Highway route—the route approved by the President and the Congress in 1977—remains the chosen route. That route can be completed quickly and, given the existing infrastructure, can be done with minimal additional impact on the environment. In contrast, other suggested routes, such as the so-called "over-the-top" route through the Beaufort Sea and then south through Canada, present enormous engineering and environmental challenges and have not undergone formal feasibility and environmental reviews and, thus, cannot be completed in a timely or environmentally friendly manner.

- Expedited Process. The legislation should also include an expedited approval process for the Alaska portion of the Alaska Highway pipeline corridor that parallels and builds on the process set forth in the 1976 Alaska Natural Gas Transportation System legislation.

- Tax Incentives. Legislation should provide for necessary tax benefits to ensure that this project, which is so important to national interest, is actually built. Provisions that would entitle the pipeline owners to take both accelerated depreciation and investment tax credits on the pipeline assets have been used successfully in the past to stimulate investment. In addition, consideration should be given to provisions which would reduce financial risk resulting from widely fluctuating gas prices—perhaps a tax or royalty credit when prices fall below a specified floor. Given the inherent uncertainty as to the economic feasibility of a project of this magnitude, such incentives should help tilt the scales in favor of construction of the project.

2. Build American Industry and Create American Jobs

- United States and Canadian Steel Usage. Subject to limited exceptions, legislation should require that only steel manufactured or produced in the United States and Canada be used for the construction of the Alaska portion of the ANGTS. The exceptions would be where the cost of United States and Canadian steel is determined to be unreasonable or where a finding is made that use of such steel is inconsistent with the public interest.

- Use of a Project Labor Agreement. Legislation should mandate the use of a project labor agreement wherein involved contractors and unions would agree to a total ban

on strikes, lockouts, work slow downs, and other disruptive activities. Such a provision would further the goal of expeditiously constructing the pipeline and at the same time recognize the public interest in labor stability surrounding the construction, operation, and maintenance of the pipeline.

3. Future Access of Natural Gas Developers to ANGTS

- Access for New Gas Discoveries. It is necessary to mandate that, in the event of new discoveries on or around the North Slope or in Interior Alaska, and whether on federal or state lands, the owners of these discoveries will have access to the pipeline in order to market their gas. It is estimated that undiscovered gas reserves may be on the order of 100 TCF, or more. Legislation should give the Federal Energy Regulatory Commission (FERC) clear authority to require the owners of the Alaska portion of the Alaska Highway project to expand the capacity of the pipeline in order to accommodate all new discoveries. Absent such a provision, new gas discoveries could be left at the back of a long queue of gas awaiting shipment or, worse, indefinitely stranded in place because, unlike in most areas in the lower 48 states, one pipeline will be the sole source of available transportation.

- Encouragement of New Pipeline Participants. Legislation should also encourage the equity participation of all interested and financially viable energy companies, including North Slope producers and gas pipeline companies. Today, producer affiliation is no longer a valid reason to exclude a potentially significant source of needed equity capital. FERC's present open access and nondiscrimination rules and regulations are sufficiently evenhanded to allow equity participation by everyone regardless of whether or not they are affiliated with the North Slope gas owners.

4. Jobs for Businesses, Alaskans, and Alaska Natives

- Alaska and Alaska Native Hire. In order to provide much needed jobs and training for Alaskans, the legislation should require that the persons constructing the Alaska portion of the pipeline adopt programs to train and employ Alaskans, to the extent permitted by existing laws. Special emphasis should be placed on the recruitment, training, and employment of Alaska Natives who, after all, will be particularly impacted by the construction and operation of this new pipeline. To ensure that these provisions are properly implemented, periodic reporting requirements should be included in the legislation.
- Alaska Businesses Hire. Similar provisions just discussed with regard to Alaska and Alaska Native hire should provide that Alaska businesses shall be utilized to the

extent permitted by law. The same rationale for employing Alaska residents applies to employing Alaska businesses.

5. Access to In-State Gas Resources

- Alaska Access to Gas. It is important for the social and economic development of Alaska that Alaska citizens and businesses have access to sufficient gas to serve their needs. It makes sense for Alaska—the source of huge quantities of gas—to have access to needed amounts of the commodity. Provisions in the legislation should ensure the owners of the Alaska portion of the pipeline make the necessary accommodations to ensure such access.

In conclusion, I hope these principles can serve as some useful guideposts in crafting legislation. We would be willing and honored to work with you and your staff to develop specific language implementing these principles.

Sincerely,

Tony Knowles
Governor

cc: The President of the United States
The Honorable Dick Cheney, Vice President of the United States
All members of Senate Energy Committee
The Honorable Ted Stevens, U.S. Senator, Alaska
The Honorable Don Young, U.S. Congressman, Alaska
The Honorable Gale Norton, U.S. Secretary of Interior
The Honorable Spencer Abraham, U.S. Secretary of Energy
The Honorable Colin L. Powell, U.S. Secretary of State

Scott Heyworth
Testimony to
U.S. Senate Cmte.

Good Morning Senators:

I wish to thank Senators Bingaman and Murkowski for inviting me to testify.

My name is Scott Heyworth. I was born in Alaska and am currently serving as a Public Safety Commissioner for the Municipality of Anchorage under our Mayor George Wuerch, and a former Port Commissioner under then Mayor Tony Knowles. I am also the Chair of the Citizens Initiative for the All-Alaskan, All-American Gasline, which is the subject of my testimony here today.

I have been a member of the Anchorage Independent Longshore Union for 28 years. All of my fellow union brothers and sisters mourn the losses of our fellow union Policeman and Firefighters, along with Military and Civilian casualties and strongly support the work of the construction crews, fire, medical, police, and rescue volunteers. As do all Alaskans.

Ladies and Gentleman of the Committee:

We can have our corporate boardrooms, our economic forecasts about the various gas pipeline scenarios, our hearings, our jurisdictions, our political parties. Yet we also need to look at our rock bottom principles of Democracy, which brought forth this great Country, this Capital and this very room at this precise moment. One of those principles our forefathers fought and died for is the right of citizens to petition their government.

The Alaska State Constitution, Section 6, Declaration of Rights, reads as follows:

"The right of the people peaceably to assemble, and to petition the government shall never be abridged".

Giving oil companies Federal incentives, tax breaks, tax credits, and special interest considerations are not the answer to the United States' energy problems. Changing the ANGTA treaty is just one of the myriad problems. It is not an answer.

The answer is to build the one project you have heard so little about today, the All-American LNG route to Valdez paralleling the Trans-Alaska Pipeline System, which this committee has the jurisdiction over. Which would you rather have control of? A 3,000 mile gas pipeline in a Foreign Country, Canada, or two parallel 800 mile pipelines going down the exact same corridor in the United States of America? Isn't this simple, defensible, and in the best interests of all Americans?

Alaska's State Constitution, Article 8, Section 2, gives Alaskans a say in the commercialization of their State's natural resources. And Alaskans are strongly saying they want their Natural Gas to be commercialized in their state and therefore in America, not Canada. In March, May, and June of this year I commissioned three polls and they all show that the majority of Alaskans support the All-American route to Valdez by over a two to one margin. Our largest city alone, Anchorage is in favor of the All-American route by a 65% per cent margin.

Alaska's Lt. Governor, Fran Ulmer, recently certified our Citizens Initiative Petition. This allowed us to begin gathering signatures to place the initiative on the Nov. 6, 2002 ballot. The Petition to have the State of Alaska build and secure financing for this All-

American project is now circulating statewide. In the first 18 days since certification we have collected over 25% of the necessary signatures. The citizens of Alaska are signing it in record numbers. The response can only be deemed phenomenal. Alaskans have this issue patriotically figured out, despite being distracted with concerns over the threat of terrorism this country is now facing. Building a gas pipeline in America, not Canada, is their choice.

They support the one project that is already permitted, already engineered, is environmentally sound, and has signed project labor agreements with most Alaska Unions. It brings the most jobs to Americans, provides most revenues to our State treasury, provides in-state gas use of our own resource (something any Canadian route does not do) and provides gas to our own U.S West Coast cities where the real energy shortages are. El Paso Natural Gas has proposed 5 LNG receiving terminals on the West Coast, which could receive Alaskan LNG. There are no gas shortages in the mid-west or Chicago. Cheaper Canadian and domestic gas is closer to that area than any 3,900 mile gas pipeline from Alaska.

These are extraordinary times and it takes extraordinary vision to see past ancient political myths. It is time to reevaluate oil industry special interest legislation, sever our dependence on Mid-East natural resources, and protect America's Natural Oil & Natural Gas Reserves on the North Slope. We cannot build this gas pipeline through Canada just because it is economically beneficial for the Oil Companies.

We need to put America's energy interests first. Unlike the Governors' or the Producers' proposed legislation, the Citizens Initiative, which establishes a State Gas Authority, does not need any Federal legislation to build this All-American project because it will be a publicly owned entity.

Finally Senators, if anyone is advocating to open ANWR to lessen our dependence on Foreign and Mid-East oil & gas supplies, then I am sure, using the same logic, they would advocate to build the All-American gas line to Valdez to avoid going through a foreign country for security reasons. I believe Americans, today, understand this very simple concept.

THANK YOU

Article 4 of 200
Financial Post: Canada

Bush, Congress at odds over pipeline route: Natural gas in Alaska

Peter Morton

10/03/2001
National Post
National
Page FP5
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WASHINGTON - Both the U.S. Congress and the administration of George W. Bush, the President, are anxious to tap into the vast natural gas reserves in Alaska, but are at odds over which route to pick.

The U.S Energy Department told a Senate Energy Committee hearing yesterday that Alaskan gas is vital to the interests of the United States.

"The vast natural gas resources on Alaska's North Slope are one of the largest, most promising and most secure domestic energy supplies that could become available to America's consumers," said Robert S. Kripowicz, Acting Assistant Secretary of the Energy Department.

But Mr. Kripowicz refused to endorse either of the two major competing pipeline projects.

"We are committed to working with the private sector and with Canada to ensure that any commercially viable proposal to bring this natural gas to market is processed as expeditiously as possible," he told the committee.

Tony Knowles , the Governor of Alaska, pushed the committee to endorse the Alaska route, especially since the Alaska Natural Gas Transportation Act has already been approved in the United States. The Canadian equivalent, the Northern Pipeline Act, has already been approved by Parliament.

Mr. Knowles argued that the 2,900-kilometre pipeline from Alaska's North Slope to Alberta would create 160,000 jobs and be the least environmentally damaging of the two proposed lines. But, he said, the U.S. government must provide incentives in the form of a dramatically speeded-up depreciation and a 10% tax incentive to make the project economically viable.

Dennis McConaghy, co-chief executive officer of Foothills Pipe Lines of Calgary, told the committee the Alaska route would be virtually ready to go since it rece' 'd framework approval in the mid-1970s.

The Alaska route suffered a major setback after a consortium that included Exxon-Mobil, BP PLC and Phillips Petroleum Co., said the US$15-billion to US$17-billion route would generate a return of up to 11%, which made it uneconomic.

The competing proposal is the Northern Gas Pipeline Project from Arctic Resources Co. of Houston. It wants to build a pipeline from the Alaskan North Slope through the Beaufort Sea, where it would connect with a Mackenzie Valley pipeline.

Volume 79 Number 191 [NL]October 3, 2001

PRODUCERS, CONGRESS VIE ON ALASKA LINE[NL]'Chicken-and-egg problem':

ExxonMobil official [PARA]Washington-The three majors studying an Alaska natural gas pipeline urged the US Congress Oct 2 to quickly pass legislation streamlining the regulatory approval process and outlining tax incentives for the project. Without that kind of certainty, they said, it would be difficult to move forward with a multi-billion dollar pipeline designed to move Alaskan North Slope gas into Canadian and continental US markets.

But several members of the Senate and the Bush Administration suggested that without a formal application in place, legislation would be premature. "It gets to be a bit of a chicken-and-egg problem," Terry Koonce, president of ExxonMobil Production, acknowledged to the Senate Energy and Natural Resources Committee. ExxonMobil, BP and Phillips Petroleum are spending about $100-mil to study if a pipeline is economically feasible and, if so, which of two routes under consideration to endorse.

The producers, which last month issued an interim report saying neither route looks feasible because of depressed gas prices, pressed the committee to take up a bill they wrote creating "thorough but expedited" permitting for the prevailing pipeline. The bill also would guarantee quick resolution of any legal disputes, create an Office of Federal Pipeline Director and outline tax incentives.

But Sen. Frank Murkowski (Republican-Alaska) asked producer officials why Congress should not wait until a formal application is filed. He expressed concern Congress essentially would be creating regulatory schemes in a vacuum because it would not know project details.

Joseph Marushack, vice president of Alaskan gas for Phillips, argued producers would be more comfortable with the project's viability, and be more inclined to continue the study, if Congress acted before a route is chosen. "We are trying to chip away at areas of risk," including cost, market conditions and permit processes, he said.

The industry proposal is for a route-neutral bill, a proposal opposed by Alaska, which supports the southern route, extending from Prudhoe Bay south through Alaska into the Yukon and British Columbia or Alberta. The other option, the so-called over the top or northern route favored by many Canadian leaders, would run from Prudhoe Bay under the Beaufort Sea and through gas-rich areas of the Northwest Territories.

Alaska Gov. Tony Knowles told the committee legislation should mandate the southern route, which at an estimated $17-bil is about $2-bil more expensive than the alternative. The producer consortium is expected to endorse a route in a few months. Lawmakers also were divided over requests by Alaska, and at least one producer, for federal incentives to build the line. Knowles and Phillips' Marushack endorsed a provision already proposed in the Senate and passed in the House to accelerate depreciation for gas pipelines at a seven-year rate rather than the typical 15 years.

Knowles also suggested Congress could adopt a 10% investment tax credit, while he and Marushack suggested a production gas tax credit tied to a floor price of gas as a way to provide investor confidence.

But Sen. Ben Nighthorse Campbell (Republican-Colorado) asked: "Why should there be subsidies for this gas and not for (gas produced in) the lower 48?" Knowles and Murkowski insisted federal incentives were not subsidies, and the size and natural interest in the project make it unique.

-Mark Davidson, Cathy Landry
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Firms may drop gas line claims

By SAM BISHOP
Fairbanks News-Miner Washington Bureau

WASHINGTON--Several companies may drop their multi-billion claim to earnings from a proposed natural gas pipeline to the Lower 48, an action that could remove a question mark hanging over the cost of the line's so-called southern route, a pipeline executive said this week.

Dennis McConaghy, co-chief executive officer of the Calgary-based Foothills Pipe Lines Ltd., told the Senate Energy and Natural Resources Committee that his firm is nearing an agreement that would wipe out the $4.2 billion claim.

In the late 1970s, Foothills and a half-dozen companies joined efforts to build the Alaska Natural Gas Transportation System, McConaghy said after the hearing. That line, authorized by the U.S. and Canada governments, was to roughly follow the Alaska Highway.

Only two partners are active today. The rest withdrew after spending about $250 million, McConaghy said. In withdrawing, the former partners reserved the right to recover their costs, plus interest, if the line were ever built, he said.

Today, the interest on that $250 million has ballooned the total claim to $4.2 billion. That's a substantial figure compared with the total pipeline construction costs, which major gas producers have estimated at $15 billion to $20 billion.

Sen. Frank Murkowski, R-Alaska, asked McConaghy about the claim, called a "contingent liability," during the hearing Tuesday.

McConaghy said he believes Foothills and its partner, TransCanada PipeLines Ltd., are within a month of virtually eliminating the claims. He said the former partners of the Alaskan Northwest Natural Gas Transportation Co. are "re-enlisting."

To re-enlist, he said, they must relinquish the claims.

Among the partners is Williams, which operates a refinery in North Pole. Others include Duke Energy, El Paso Corp., Sempra Energy, Enron and Pacific Gas and Electric.

Foothills' U.S. counsel, J. Curtis Moffatt with VanNess Feldman, said the $4.2 billion claim has been given greater significance than it deserves by opponents of the southern route.

The implication by opponents has been that the former partners would have to be paid off with money obtained by raising the charges for transporting the gas through the pipeline. Moffatt said it has never been certain that would happen and that the payment is contingent on other factors.

Also, he said, the $4.2 billion is merely a theoretical accounting sum that the active partners report to the Federal Energy Regulatory Commission. He said the number is likely to be "very near zero."

If Foothills does seek to repay partners by adding to its gas transport fee, Moffatt said, it would only be to the extent that the original partners' contributions were useful to the final project. Any such charges would have to be approved by FERC.

Moffatt said the former partners have no incentive to demand the money. Rather, their interests are in making the project happen, he said.

And those former partners don't have any desire to jump ship to the alternative northern route, Moffatt said. That line would carry gas east from Prudhoe Bay into Canada, where it would travel up the MacKenzie River valley into Alberta.

"After a long, detailed, litigated selection process and subsequent review by the president of the U.S. and Congress, the southern route was selected as superior, and we all believe that it still is," Moffatt said.

He described the former partners as "very sophisticated," and said they have vast experience in the details of siting and operating large gas lines.

Despite all this, Moffatt said, southern route opponents have gotten some mileage from the contingent liability question.

But Arctic Resources Co. President Bob Murphy, whose Houston-based company backs the northern route, said his estimates of the southern route's costs have never included the contingent liability.

"When we have looked at the relative economics of the southern route versus the northern route, and when we reached the conclusions we have reached, we did so on the assumption that the southern route would not be penalized by these past claims," he said.

However, he added, "were they to be penalized by past claims, I think our feelings would become even stronger."

The northern route is just cheaper, which is good for everyone--Lower 48 consumers, Alaskans and Canadians, he said. Arctic Resources puts the cost at about $7.8 billion.

John Katz, head of Gov. Tony Knowles' office here, said the news from Foothills was good for the southern route.

"We think it's very important that the issue of the contingent liability of potentially $4.2 billion be resolved as soon as possible," he said. "Otherwise it remains a significant obstacle to the ANGTS project."

Moffatt said teams from Foothills and the other gas pipeline companies are working in Calgary this week and Houston next week to recreate the partnership.

'Fiscal certainty' sought for gas line

By SAM BISHOP
Fairbanks News-Miner Washington Bureau

WASHINGTON--A Phillips Alaska executive, appearing Tuesday before a Senate committee, conditionally endorsed a southern route for a natural gas pipeline.

But the company and two other major gas producers remain opposed to a government mandate for that route. Executives for the three also reiterated that, so far, none of the proposed pipeline routes pencils out.

"This project is not economic regardless of the route selected," Phillips Vice President Joe Marushack said.

Marushack said controversy over route selection is obscuring the need for legislation to speed up federal agencies' reviews of the project. Such speedy review is needed, the companies say, so that potential earnings from gas sales would not be delayed.

Marushack said Phillips believes the best pipeline path from Prudhoe Bay is the southern route, passing through Fairbanks and then paralleling the Alaska Highway into Canada. The company is prepared to endorse that route if doing so would improve the chances of federal legislation, including changes to tax law, passing Congress.

Exxon Mobil and BP executives declined to endorse any route, and Marushack added several conditions to Phillips' support for a southern route:

* Federal legislation, Marushack said, cannot require U.S. steel and cannot require project labor agreements with unions.

* The legislation should create a "coordinated, streamlined regulatory process," such as that outlined by the major companies in a draft bill released earlier this year.

* The bill should offer "federal fiscal relief that will ensure the appropriate sharing of risks and benefits."

* The state of Alaska should provide "fiscal certainty."

Just which route a pipeline might take has been a significant sore spot in and out of the Capitol. The U.S. House passed legislation mandating the southern route in early August. The Senate has not agreed to the House language though.

Bob Malone, BP's regional vice president, said "the gas pipeline that BP will support will be the pipeline to which Alaskans, Canadians and the federal government can all agree."

However, he added, "no single party can be perceived to have monopoly rights to build a pipeline."

Foothills Pipe Lines Ltd. of Calgary holds rights of way to much of the southern route. Foothills obtained the rights after Congress approved a southern route in the late 1970s, and it says Congress ought not to open up the field to other projects.

Terry Koonce, president of Exxon Mobil Production Co. said cost is the major factor obstructing the line.

"It's important not to have any mandates, including route, that could increase the cost and possibly prevent any project from being built," he said.

A recent report from Phillips, Exxon Mobil and BP concluded that a gas pipeline would produce no more than a 10 to 11 percent return on equity, lower than what would be considered economical considering the risk. The companies own rights to about 35 trillion cubic feet of North Slope natural gas.

The producers said they continue to examine the possibility of a pipeline but have no immediate plans to apply for federal permission to build one.

On the subject of federal financial incentives, BP and Exxon Mobil agreed to disagree with Phillips. "Exxon Mobil prefers a level playing field that permits the market to operate unencumbered," Koonce said.

Ken Konrad, BP's senior vice president for Alaska gas, said after the hearing that BP isn't asking for any federal tax breaks or incentives. It just wants the federal regulatory process to be streamlined, he said.

In contrast, Phillips is backing two tax ideas. One would allow it to write the cost of the project off its taxes in seven years rather than the standard 15.

The other would give companies a credit on their federal income taxes during times of very low gas prices. Gas prices in the United States have fluctuated between $2 and $10 per thousand cubic feet within the last year.

"This price uncertainty and volatility poses substantial downside risk for the project," Marushack told the committee. He suggested that credits could initially kick in if gas prices fell to $1.25 or less.

The three major oil companies presented a united front on several questions, though. They all endorsed creation of a streamlined federal regulatory process. The companies want legislation ordering that any pipeline application and any environmental impact statements be approved by the federal government within 18 months. They also want a federal pipeline office to

coordinate decisions. And they want any court challenges to the legislation to be prompt, limited in scope and only filed in the Washington, D.C., appeals court.

Neither did any of the oil companies like the idea of mandated use of U.S. steel or Alaska and union hire provisions. Those ideas are backed by Gov. Tony Knowles, who was the lead witness at Tuesday's hearing.

The oil companies were also unanimous in asking the state of Alaska to promise them stable, predictable tax policies.

Konrad, BP's Alaska gas vice president, said after the hearing that the companies don't want the kind of multi-billion dollar tax disputes that they've fought with the state of Alaska over oil. The gas project can't support such uncertainty, Konrad said.

Such disputes arose from disagreements over how much the oil was worth and thus how much the state deserved in royalties and taxes.

But gas is sold in a different manner and the prices are clearly set, Knowles said after the hearing, so such disputes shouldn't arise.

Knowles said he hadn't talked with oil companies about what sort of "fiscal certainty" they were seeking and doesn't plan to do so until the companies have committed to the southern route.

"Until it's decided what the route is, how can you talk about what kind of fiscal regime is going to take place?" Knowles said in an brief interview.

Republican Sen. Craig Thomas, from the gas-producing state of Wyoming, challenged Knowles to explain why Alaska gas should get special tax treatment. Knowles has proposed accelerated depreciation and investment tax credits for the Alaska gas line.

Knowles said incentives are justified because "there is real concern about whether we will be able to meet (the) demand."

Later, he noted that the state of Wyoming itself has investment tax credits for coal bed methane, heavy oil development and alternative energy sources.

"This is a commonly used tool for projects that are deemed in the national interest," Knowles said. Besides, he said, Wyoming gas will always have an advantage over Alaska's because Wyoming is in the middle of the national distribution system and its gas isn't burdened with the pipeline's projected $2 per thousand cubic feet transportation charge.

September 24, 2001

Subject: Legislative Strategy Survey
North Slope Gas Development

Dear Alaskan Legislator

This is my initial contact with you to explain the interview and survey process I will be using as part of my contract work for the Legislative Council. I will be identifying areas of consensus on the major issues and alternatives related to legislative action on bringing North Slope gas to market.

I will contact your office this week to schedule an appointment (up to an hour long) at a time convenient for you over the next several weeks. My preference is to do the interview face-to-face in the privacy of the Anchorage Legislative office setting. If you aren't going to be in the Anchorage area during October, then we can work out an alternative, possibly a phone interview.

A week prior to the appointment I will get you a background paper for the discussion. Also, members of your staff are free to attend if you wish. My interview records will keep any comments anonymous and there will be no attribution of comments or positions in my written and verbal report to the Legislative Council.

Attached to this note are several lists: (1) Major Gas Development Issues; (2) Potential Benefits and Impacts of a Gas Development Project; and (3) Relevant Existing Alaska Statute References.

For this project my:

Phone and fax number is: (907) **561 – 4246**
E-mail is: **nsgas@worldnet.att.net**
Snail mail is: 1336 Staubbach Circle, Anchorage, AK 99508

I look forward to talking to you!

Harold Heinze

Major State Issues Related to North Slope Gas Development

Gas Pipeline Project Route(s)
Access to Pipeline and Gas
Gas Pricing
Alaska Hire
State Financial Involvement in a Project
Federal & Canadian Interactions
Port Authority Concept
Stakeholder Groups
Hydrocarbon Recovery & Reservoir Management

Potential Benefits

Dollars to State & Local Governments
Increased exploration activities
Paychecks for Alaskans
Gas to communities
Gas for new business opportunities
Expanded economy & higher incomes
Greater recovery of oil & gas

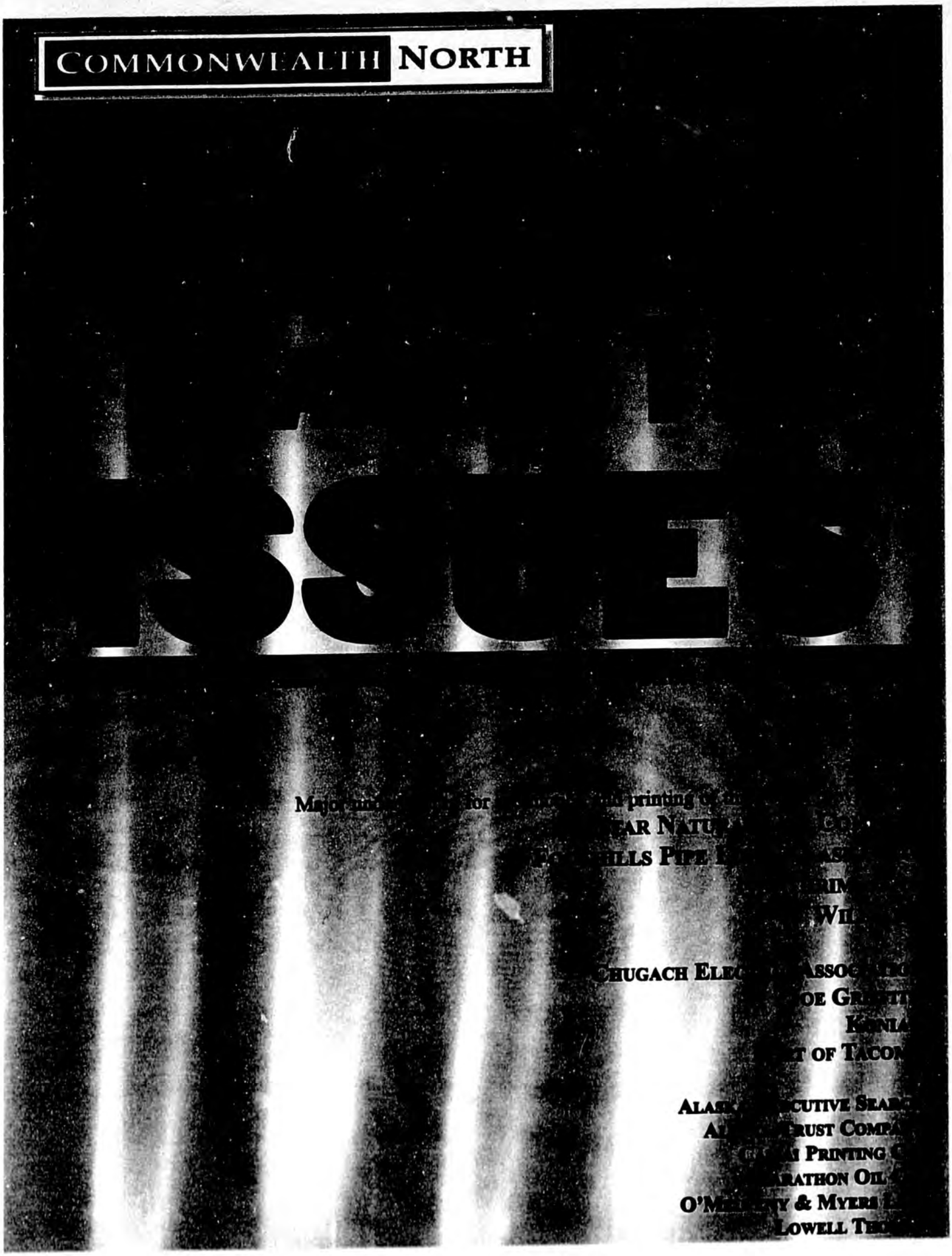
Potential Impacts

Social costs
Public Facilities
Quality of Life of Individual Alaskans
Standard of Living
Business and the Economy
Environmental costs

Existing Key Alaska Statutory References

- Sections 1 & 2 of Article VIII (Natural Resources) of Alaska's Constitution defines the Legislature as the policy maker on resource issues
- The Right-of-Way Leasing Act, Chapter 35 of Title 38 (Public Land) of the Alaska Statutes, delineates the process and requirements for a gasline
- Oil & Gas Leasing (including sale of royalty gas) alternatives and regulations are mainly covered in Sections 180, 182, & 183 of Chapter 5 (Alaska Land Act) of Title 38
- Chapter 6 of Title 38 defines the functioning of the Alaska Royalty Oil and Gas Development Advisory Board
- Chapter 5 of Title 31 (Oil & Gas) defines the functioning of the Alaska Oil & Gas Conservation Commission
- The Alaska Stranded Gas Development Act, Chapter 82 of Title 43 (Revenue & Taxation), provides alternative fiscal terms to improve gasline economics

COMMONWEALTH NORTH



Approved by the Commonwealth North Board
September 11, 2001

BACKGROUND

For over twenty years Alaska has known of the potential to develop significant reserves of natural gas on the North Slope. However, markets, divergent ownership interests, and project economics have not justified developing these reserves.

Recently, there have been three changes in the situation: the alignment of ownership of North Slope oil and gas interests among the major producers, the development of new technologies that create greater efficiencies, and the price of natural gas have combined to increase the prospective marketability of the gas.

Developing this potential, from concept to construction, from construction to delivery, and from delivery to sales, would create significant value for Alaska. The goal of this study is to inform our members, policymakers, and other interested parties and engage them in an examination of the issues and how Alaska's interests can be optimized and protected.

The report analyzes the issues, identifies a process for addressing them, and recommends policy principles that can guide the State in answering the question: How can the best interests of the people of Alaska be realized in the commercialization of the North Slope natural gas resources?

INTRODUCTION

• Since its inception in 1979, Commonwealth North has studied and published reports on North Slope resource issues. Summaries of the following reports are available on its web site www.commonwealthnorth.org

1. "Solutions to the National Energy Crisis: Why Not Alaska?" November 1979

2. "North Slope Natural Gas: Transportation Alternatives and the Promise of a World Scale Petrochemical Industry" March 1980

3. "Moving North Slope Natural Gas to Market: A Positive Alternative" November 1981

4. "An Alaskan View of ANWR" October 1989

• In this report the Study Group focused on significant public policy issues that are within the power of the State of Alaska to address. The Group avoided making specific "how to" recommendations that are the purview of those who will have to make design decisions and from recommending a specific project or route(s).

• The report organizes its findings in six categories followed by recommendations:

1. Alaska North Slope (ANS) Natural Gas Supply

2. Markets for ANS Natural Gas

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William J. Tobin

Executive Director

Duane Heyman

October 3, 2001

Dear Legislator:

Please find enclosed your copy of ***"Bringing Alaska's North Slope Gas to Market: Framing the Issues,"*** a study co-chaired by Richard Barnes and UAA Chancellor Lee Gorsuch.

The report was unveiled at a Forum on September 25, 2001. The topic of commercializing Alaska's natural gas continues to draw widespread attention and our Forum was no exception. The unveiling event drew an audience representing our diverse membership along with policymakers, industry and media who were all present to hear about our work.

Special thanks to the study group members for their long hours and patient deliberation, and to all the individuals that testified and provided critical information to the group. It was no easy task to synthesize the complexity of this topic. The dedication of the study group resulted in a report that will help concerned Alaskans better educate themselves on a difficult and evolving issue.

In addition to the Legislature, the report will also be provided to our membership, the Governor's Gas Cabinet and the Alaska Highway Natural Gas Policy Council, relevant individuals in the U.S. Senate and U.S. Congress, statewide media and other constituencies working on the issue. The report is also available on our home page: *www.commonwealthnorth.org* along with the PowerPoint presentation used at the unveiling event which outlines the findings and recommendations of the study.

Please feel free to contact me if you have questions or comments about the report, or if additional copies are requested.

Sincerely,

Duane Heyman

Duane Heyman
Executive Director

Enclosure

4. ANS Gas Delivery Options

5. The Decision Making Process

6. Stakeholders in the Commercialization of ANS Gas

7. Alaska's Interests in Commercialization of ANS Gas

Recommendations

• Commercialization of ANS gas is dependent upon a viable system that delivers the gas to its market(s). A number of projects are under discussion that would construct a pipeline to satisfy some of these transportation needs. The State of Alaska has a vested interest in how these projects may be developed and implemented. Most notably the projects being discussed are described as:

1. The "Highway," or "Alcan" route. This pipeline would run south to the Fairbanks or Delta Junction area, then approximately follow the Alaska Highway until it connects with other Canadian gas transportation systems.

2. Variations of the Highway route include a "spur" or "Y" line that would run south from Fairbanks or Delta Junction into the South Central Alaska area. Depending on size and location, this could provide gas for local or export uses. The "hub" concept is based on a "Y" line with physical characteristics and business arrangements allowing for access to multiple users and multiple markets.

3. An "over-the-top" pipeline would run underwater eastward from Prudhoe Bay north of the Arctic National Wildlife Refuge coast and turn south overland into Canada until it connects with other Canadian gas transportation systems.

4. Liquefied Natural Gas (LNG). A pipeline to Alaska tidewater for liquefaction of natural gas in Alaska and shipping it to East Asia and American markets.

5. The North Slope Borough, the Fairbanks North Star Borough and the City of Valdez formed the Alaska Gasline Port Authority to utilize tax-exempt pipeline financing. Other project sponsors are also considering tax-exempt financing.

SUMMARY

From Alaska's point of view, an ideal ANS gas commercialization project might result in:

- High income to the State treasury
- Economic benefits from construction activity
- Many long-term project maintenance jobs

- In-state access to ANS gas for homes, business, electric utilities and industrial plants

- In-state ownership and control of a project

However, the Study Group has found that detailed analysis of the variables reveals a real-world set of constraints that are unavoidable:

- Market economics. This is the most critical element. Any ANS gas commercialization project must be economically viable. Any of the pipeline alternatives being discussed would be one of the largest industrial projects in the history of the world. Without a compelling economic rationale, management focus and massive financing simply will not be available.

- Any trade-off that reduces the highest financial rate of return must be weighed against its potential to make the project uneconomic. Such consideration applies as much to potential revenues to the Alaska treasury as it does to project proponents.

- World market forces, U.S. market forces, and international and domestic politics are all factors. No decision can be made in a vacuum solely from one point of view.

- The real challenge to Alaska's leaders is, and will continue to be, maintaining clarity of vision and purpose to realistically optimize the combination of financial and beneficial returns from any project without burdening it to the point where it is uneconomic.

- Alaska will need to design and develop a fiscal regime that maximizes the full economic benefits of gas development and minimizes the costs associated with a project of this magnitude.

FINDINGS

ALASKA NORTH SLOPE (ANS) NATURAL GAS SUPPLY

1. The ANS gas potential may be substantially greater than the 35 trillion cubic feet (tcf) of known existing reserves. If it is as large as some believe, in excess of 100 tcf, more than one major commercialization project may be feasible. To put these quantities in perspective, known existing gas reserves are sufficient to provide 10% of all U.S. gas needs for about fifteen years. 100 tcf could supply 10% of all U.S. needs for about forty years, based on American Gas Foundation forecasts.

2. Absent a commercially viable system to deliver ANS gas, the exploration and discovery of gas will be incidental to the exploration and development of oil. The current high level of activity and interest in exploration is in anticipation of a gas pipeline.

3. As oil reserves are depleted, ANS gas reserves will diminish in value as a means of enhancing oil recovery. ANS gas will become "stranded" unless a commercially viable delivery system is developed.

Markets for Alaska North Slope Gas

1. It appears that the potential for commercializing ANS gas has improved as a result of a generalized increase in the long-term price of gas, new demand from gas-fired generation plants across the country and prospects for increased demand in the future. However, the price volatility of the past year strongly demonstrates the commodity nature of the Lower-48 market.

2. Increases in gas prices, if sustained, not only make delivery of ANS gas more feasible, they also induce new, competitive gas supplies into the market e.g. the Mackenzie Delta, Nova Scotia, coal bed methane, an increased rate of drilling and imported LNG.

3. Export of Alaska LNG remains a potential option for commercial development of ANS gas. Since 1967 Cook Inlet LNG has been shipped to Japan. Current Asian LNG prices are strong, with demand growing. Projections for potential new demand around 2010 may create an opportunity to market Alaska LNG under long-term contracts.

4. The cost of supply to gas markets in the Lower-48 will largely determine which, if any, of the competing Alaska projects or routes can deliver gas at the most competitive price. While cost is important to serve the Asia LNG markets, political stability, diversification of supply and politics between the U.S. and market countries also have influence.

5. Long-term commitments will need to be in place to finance any commercialization alternative.

Alaska North Slope Gas Delivery Options

1. The various gas commercialization options, ranging from about $8 billion up to $20 billion, are among the largest and most costly industrial projects in history.

2. There are multiple gas processes (dry gas, liquefied gas, and gas to liquids) as well as multiple gas products and markets and delivery routes, each subject to market price competition.

3. Alaska (Phillips and Marathon) has been exporting Cook Inlet LNG to Asia for over 30 years through an existing delivery system.

4. Economy of scale is a major factor in the relative competitiveness of a particular process, project or route, particularly given the distance of ANS gas from a market. Different projects have different threshold numbers that need to be compared on a consistent basis for the State to see a clear picture of available options.

5. Depending on estimates of the total supply of ANS gas, construction of any one alternative has the potential to delay competing projects, possibly for a long time. If some 100-tcf estimates of ANS gas can be realized, more than one project might ultimately be financed and built. However, conflicting demands for labor and materials must be resolved. If very large ANS gas reserves cannot be proven prior to construction, there must be exploration success to justify a second project.

6. As compared to most pipelines, the ability to expand an Alaska pipeline is important. It should be capable of substantially expanding its initial throughput capacity to accommodate future discoveries and production of ANS gas.

The Decision-Making Process

1. Delivery of ANS natural gas to market is economically challenging but technically doable.

2. A challenging aspect of any project is crafting a solution acceptable to the major stakeholders.

3. Some ANS producers are using "Seven Lenses" of evaluation for the alternatives they are analyzing to categorize the various stakeholder interests:

   a. Economics
   b. Environment
   c. Gas access
   d. Jobs
   e. Revenues to Alaska and Canada
   f. Safety
   g. Timing

4. "Open season," the Federal Energy Regulatory Commission (FERC) process in which shippers make binding offers of long-term commitments, will provide the flow volume information needed for actual pipeline capacity design. Some modification of traditional contract terms may be needed to accommodate in-state use of gas.

5. The State of Alaska has standing to intervene in FERC hearings if it chooses to do so.

6. FERC has no pipeline or rate jurisdiction over an LNG export project. Instead, the in-state Regulatory Commission of Alaska (RCA) has jurisdiction.

7. Competing project sponsors dispute which governmental agencies have jurisdiction over permitting and also dispute the current status of permit applications.

8. The State of Alaska is not yet unified in its management of this opportunity. In particular, the Administration and Legislature are not yet working harmoniously to identify and maximize the State's interests.

9. The State's 12.5 percent royalty share by itself is an insufficient quantity to support a stand-alone project.

10. All proposed projects are subject to potential delays from environmental, permitting and legal problems and indigenous peoples' opposition. The "over-the-top" route has the following additional burdens:

   a. Legislative, Gubernatorial and Congressional opposition
   b. Alaska's Interior and Cook Inlet regions have long-term needs for gas that many believe an in-state route could supply. An over-the-top route would require a separate line to meet in-state needs.

11. Both the Canadian and United States federal governments control economic incentives that could significantly affect project economics. Rules on tax-exempt financing, depletion, tax credits, depreciation and tax rates could be modified to support the project. To a lesser extent the State of Alaska has available deferred taxation and other incentives.

Stakeholders in the Commercialization of Alaska North Slope Gas

1. Stakeholders include:

   a. ANS producers and project sponsors
   b. Alaska citizens and affected Canadian citizens
   c. Alaska Natives and Canadian First Nations
   d. State of Alaska and affected Canadian provinces
   e. U.S. and Canadian federal regulators
   f. Environmental organizations
   g. Potential workers, both construction and permanent operators
   h. Potential Alaska and Canadian industrial and utility users
   i. North American and Asian consumers
   j. Alaska and Canadian businesses

2. Alignment of the proportional ownership interests of ANS gas similar to that of oil may have eliminated a major barrier to commercialization.

3. Many ANS gas stakeholders have diverse and, in significant instances, competing interests with one another and non-Alaska projects that compete with Alaska projects.

4. Most stakeholders can "break but not make" the commercialization of ANS gas. Technical and financial hurdles can probably be overcome—but politics can make any alternative undoable.

5. Sound environmental controls must be integral to any gas delivery system.

6. Addressing Canadian interests must be part of any project that goes through Canada. An all-Alaska LNG route avoids dealing with Canadian interests, as does gas-to-liquids because it is based on using the existing Alaska pipeline system.

Alaska's Interests in Commercialization of Alaska North Slope Gas

1. ANS gas commercialization can create a significant long-term industry in Alaska.

2. Alternative projects or routes to deliver ANS gas to market vary significantly in their prospective economic, social, and environmental benefits and costs to Alaskans.

3. Gas commercialization could broaden the State's technological and revenue base, as well as generate direct employment and income opportunities for residents.

4. Alaska should analyze the feasibility of capitalizing on the synergies of any project to assist in providing power, transportation and communications services to rural Alaska, as could the Canadians.

5. In-state access to ANS gas from southern routes through Alaska has the potential to significantly benefit Alaska. In-state use can add to some project economics by enhancing economies of scale with a predictable need for in-state domestic and industrial uses.

6. From Alaska's point of view, no project should be excluded from consideration if it has the potential for producing an acceptable combination of financial and beneficial returns to the State.

7. The State could potentially reduce the cost of financing a gas delivery system by using its tax-exempt status to handle project financing. It may be possible that a structure that will allow for tax-exempt financing could provide the additional benefit of providing fiscal certainty to the shippers.

8. State investment in, or ownership of, a gas delivery system involves unstudied risks and benefits. As mandated by legislation, the State is contracting for a third party analysis of these issues. Such ownership may tie into the "hub" or "Y line" idea to allow access to multiple markets and provide for in-state use.

9. Cook Inlet gas supplies for local consumption are projected to be depleted unless new gas is discovered or industrial uses are diverted to local utility use.

RECOMMENDATIONS

1. The State should work to optimize its interests in the commercialization of ANS gas without undermining the commercial viability of less preferred routes or projects.

2. The State should ensure it is a full participant in the decision-making processes associated with the commercialization of ANS gas.

3. The State of Alaska should structure a public resource management corporation that can proactively manage the development of, promote, account for and explain to the people the State's natural resources.

4. The State and project sponsors need to negotiate a structure that allows for open and understandable pricing as well as a stable tax and royalty environment.

5. A unified State delegation could work with affected Canadian jurisdictions to jointly structure and promote any Canadian and United States federal incentives needed to support project economic viability. The federal governments may have many more financial and regulatory incentives to offer than do state or regional Canadian jurisdictions. Similarly, U.S. incentives should be extended to all alternatives that benefit U.S. interests.

6. The United States Congress and the federal government should be encouraged to oversee and facilitate development of ANS gas as an integral part of the nation's energy policy.

7. The State should study the risks and benefits associated with participation in the financing of a gas pipeline, including tax-exempt financing and what type of organizational structure would be required to implement it.

8. The State Legislature should provide adequate resources to ensure the State could fully support the consideration of information requests and permit applications associated with ANS gas development needs.

9. The State should take all appropriate means to identify, protect and provide for in-state gas needs in the Railbelt, Cook Inlet and other areas in Alaska.

10. The State should preserve the right to take its gas royalty in-kind at some future date under terms and conditions that are timely, fair and reasonable.

11. The State should determine how the wellhead price of gas would be determined as a condition of approving a route or project, including the possible use of a "hub" or "Y line" concept.

12. If and when a project is authorized, the State should work closely with industry and labor to ensure Alaskans are trained and employed to hold long-term jobs associated with gas commercialization.

13. The decision-making process should be as open as possible for public review and input.

MAJOR UNRESOLVED ISSUES PENDING ADDITIONAL INFORMATION

1. Any route recommendation. The Study Group feels all options should be kept open pending more refined cost and engineering estimates on the highway and over-the-top routes. Absent such information, and thorough analysis thereof, a route recommendation would be premature.

2. State of Alaska equity participation in a project. Certain broad advantages and disadvantages of State equity participation have been identified. However, information in point 1 above, plus the results of a State-contracted third party study analyzing risks and rewards of State equity participation, are needed to adequately address this subject.

3. State and Federal regulatory streamlining

4. Specifics of a "hub" or "Y line" arrangement

CONFLICTS OF INTEREST

Persons with interests in the outcome of the study were members of the study group and participated in its deliberations. Affiliations were generally well known or identified relative to specific points advocated. The study group endeavored to seek information and viewpoints from all major proponents of Alaska gas commercialization projects.

STUDY GROUP PARTICIPANTS

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ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2951 SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPLINE, 2001-02

SCOMM

129:6

Alaska State Legislature
Joint Committee on Natural Gas Pipelines
November 8, 2001, 2 PM

Testimony by Mark S. Sexton, President & CEO
Evergreen Resources, Inc.

1. INTRODUCTION TESTIMONY

Thank you for the invitation tc testify before you today. I regret being unable to do so in person, but please believe if it were possible to be with you, I would do so.

Please allow me several minutes to provide you with an overview of my company, Evergreen Resources. Evergreen is a public independent oil and gas company traded on the New York Stock Exchange under the symbol EVG.

We have provided each of you with an information packet on Evergreen, so if you want further information you can refer to them. Our purpose here is not to do a financial or investment presentation, but if any of you wish to invest, we certainly won't object!

Our operations involve extraction of natural gas from coal beds, primarily from our leases in the Raton Basin of southern Colorado. There are other coal bed methane operations in the Lower 48, some larger, and some not as extensive as Evergreen's.

But there are none executed with more care for the environment and for the communities in which we operate. To that point, the Colorado Oil & Gas Commission has recognized us for excellence – in 1996 and in 2000 as Outstanding Operator for Community Relations and in 1997 for Production Enhancement. In May 2001, Governor Tony Knowles gave Evergreen the Environmental Stewardship Award at the Annual Interstate Oil and Gas Compact Commission Meeting in Anchorage.

We have added jobs to a depressed region, bringing prosperity and vitality where previously the Southern Colorado economy was stagnating.

In the following discussion, you will hear the term "coal bed methane". Please understand that coal bed methane is another word for natural gas. They are the same, except in this case, it is natural gas that comes from coal.

Here's a quick look at the concept behind coal bed methane, our prospects in Alaska, and then we'll show you some examples of our work on our Raton Basin properties.

2. POWEPOINT SLIDES

Topics: **What is Coal bed Methane**
Description of Evergreen's Pioneer Unit
Here is what CBM looks like – EVG's Raton Basin

in place ensures that wells are drilled, cemented, completed and produced in a way that maximizes the resource.

As to our exploration plans, we also have shallow gas leases applications, pending with the state.

Evergreen and along with several other parties, applied for shallow gas leases in the vicinity of the Pioneer Unit in February 2000. Pending the granting of these leases, hopefully by the end of this year, Evergreen will negotiate with the successful lessees and then unitize the acreage. If unitization can be established in 2002, then permitting and exploration activities could also begin that year and new wells could be drilled as early as 2003 or 2004.

4. *What is your proposed south-central drilling budget for the next 5 years?*

Our proposed budget for 2002 is roughly $5 million dollars. If successful, we expect our pace to accelerate prudently each year thereafter, like we have in the Raton Basin. As an illustration, this year, we will drill, complete and place on line 140 wells in the Raton Basin. This requires in excess of $75 million dollars this year alone. To date, Evergreen's investment in the Raton Basin exceeds one quarter of one billion dollars.

5. *What is your current assessment of south-central demand for gas over the next ten to twenty years? If you have pessimistic, optimistic and best cases, please generally describe each case.*

Our view of South-Central gas demand calls for a continuation of the slow growth that we have seen for the last 30 years. During that time, yearly demand has slowly climbed from 145 BCF to about 210 BCF, an increase of about two BCF per year. Barring major changes in supplies, consumption, or pricing, we expect this trend to continue.

6. *We have heard that "deliverability," the ability to meet peak winter demand, may be a problem soon. Please discuss whether you see deliverability constraints in the next ten years. Please discuss what can be done to reduce any deliverability problem.*

As proven producing gas reserves dwindle, delivering peak volumes on the coldest winter day becomes more difficult. Short-term solutions include additional compression, recompletion of existing wells, or drilling new wells in established fields could increase peak delivery.

The long-term solution is to develop new gas supplies like coal bed methane.

7. *Finally, do you have any recommended state legislation the committee should consider to advance the development of natural gas within the state?*

Yes, there is legislation that could advance the development of coal bed natural gas.

You probably noticed that throughout my testimony, that I have prefaced my conversations with the word "IF" as in "if coal bed methane is successful, then this is what it can provide for Alaska". Here, I stress the word "IF". <pause> I am confident that if coal gas can be produced in Alaska, then Evergreen is the company to do it. We have the technical expertise and the state of the art equipment required to make CBM a technical success. So we can get gas out of the ground; whether or not we can do it economically, in many ways, rests with the decisions of the legislators in this room.

Friends of ANWR:

After 15 years of trying to open ANWR, maybe a different strategy is in order.

What is missing in the debate over ANWR - **A viable national energy program that WILL have a effect on reducing US imports with the most amount of States (people) participating.**

All you hear today in Alaska is talk about ANWR. While ANWR will have a benefit for the US, it is doubtful that it would be producing by the end of this decade. Most Americans see little benefit for them, only "rich" Alaskans with their PFD's getting richer while we destroy "their" wilderness.

There is a viable program that should be **included** in the ANWR debate that would have a tremendous benefit for Alaska and more importantly, the rest of the US. Maybe a little "sugar" for the rest of the US will slow or end the resistance in the lower 48 against ANWR, because we know few in Alaska are opposed.

A North Slope gas to liquids (GTL's) program followed by a lower 48 coal based gas to liquids program can work in 38 different states. Think of the support you may get for an Alaska program when there could be jobs, energy production, tax base and valued added industries across the US.

Also, the debate on ANWR does not include a viable way to develop the extensive gas reserves of Alaska, dramatically reduce US dependence on foreign crude and improve the US environment that WILL play to all sides of this very contentious issue.

I have long been a proponent of GTL's as one solution for Alaska's stranded natural gas and lower 48 coal based GTL's as one answer for reducing US dependence on foreign crude imports. It could also help the ANWR issue and GTL's are the ONLY viable option on the horizon that can significantly reduce US dependance on foreign crude oil and products.

If the US wants a National Energy Policy to reduce its dependence on foreign crude oil it can to look to the example of the South African's. South Africa pioneered coal gasification - gas to liquids in the 50's and expanded the program in the 70's when OPEC boycotted the US in order to reduce its imports of foreign crude.

Today with advances in GTL technology, the US can build more efficient gasification - GTL plants for far less than what it cost South Africa.

The Alaskan North Slope contains enough natural gas to make approximately 1 million barrels per day of synthetic fuels that can be transported down the existing crude oil line to Valdez for shipment to the lower 48, still leaving room for development of ANWR.

GTL's from Alaska's North Slope can start the process TODAY, educating American's with the possibilities of GTL's and the real promise of reducing US imports of crude oil and products. Coal based GTL's can produce not only the cleanest motor fuels know to man, the gasification program can also produce electricity as efficiently and environmentally effectively as natural gas.

The US has enough coal reserves in 38 states across the nation to make over 10 million barrels per day of synthetic motor fuels (gasoline and diesel) **for at least 200 years. Now this is a reduction in US imports worth talking about.**

Reliable, Affordable and Environmental Sound Energy for America's Future, GTL's Gas to Liquids. The President's "Energy Policy" with a little kicker.

One solution that can happen TODAY in Alaska and in 38 + states across America in the near future.

GTL technology is proven and cost effective.

A North Slope GTL proposal can result in the US, replacing up to 25% of its "dirty" diesel with this new clean burning fuel.

Fischer-Tropsch (F-T) produced GTL's are odorless, non-toxic and completely biodegradable on land or water according to the US EPA.

Over 36 billion gallons of these ultra clean fuels have been produced in South Africa and other locations around the world.

Alaska can become a major producer of these ultra clean fuels if it so chooses, but it will take tremendous pressure from the people and environmental community to make it happen. Alaska has enough existing natural gas to make upwards of 1 million barrels per day of these ultra clean fuels and enough capacity in the existing oil pipeline to transport these fuels; plus develop ANWR.

America is not as short of clean energy as we are critically short of a comprehensive energy policy that can wean us off foreign crude and products.

It could be that by marrying ANWR with an energy program that can benefit all Americans and physically be located in upwards of 38 States, Alaskan's can finally achieve their goal of developing ANWR.

To learn more about GTL's see our web site at www.angtl.com

Respectively,

Richard Peterson
A friend of ANWR and GTL's for a stronger Alaska and US.

ENSTAR

Natural Gas Company

ALASKA STATE LEGISLATURE

Joint Committee on Natural Gas Pipelines

November 8, 2001

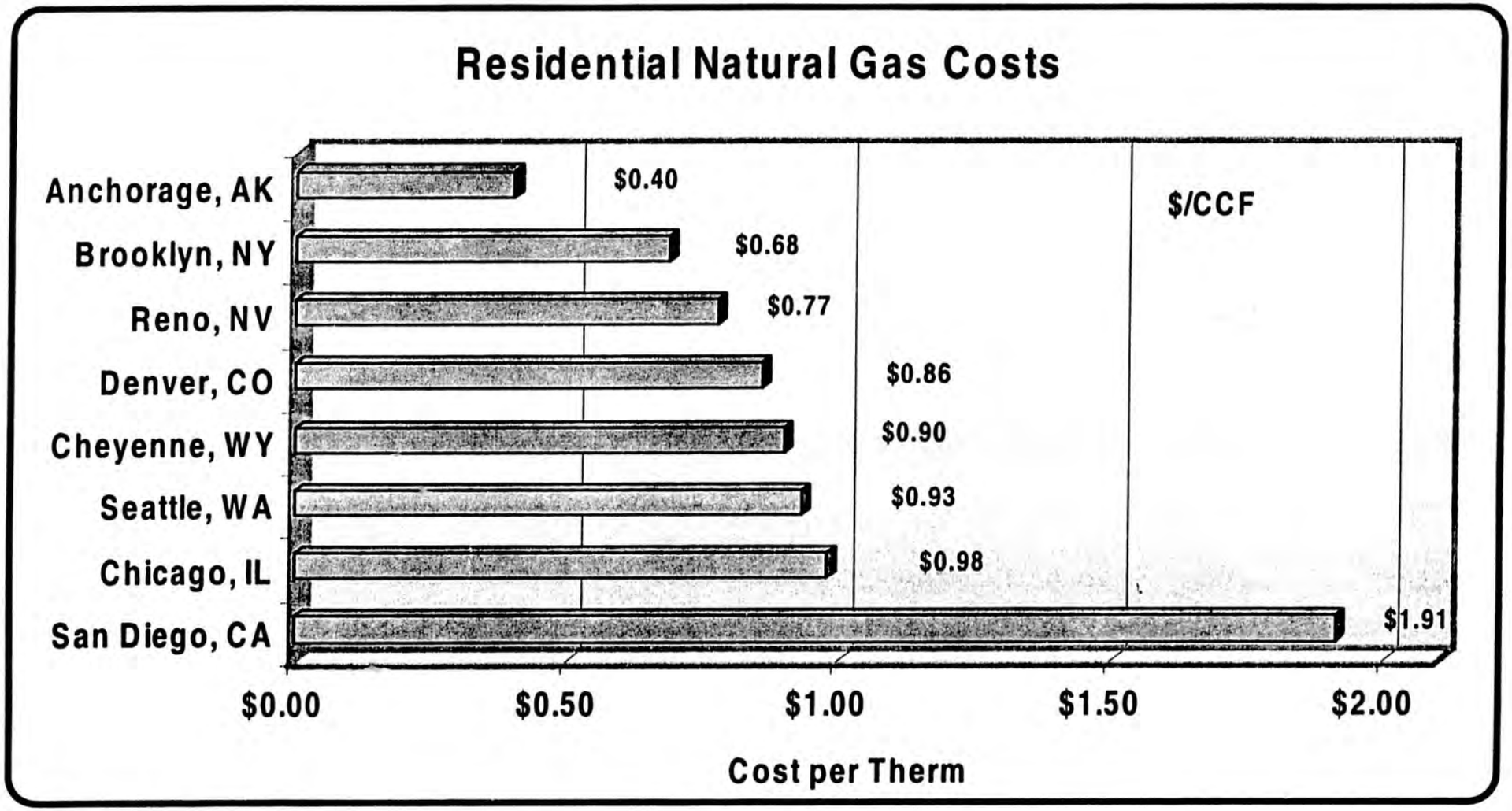
ENSTAR

- Company Overview
- Projected Gas Usage
- South-central demand & deliverability

ENSTAR

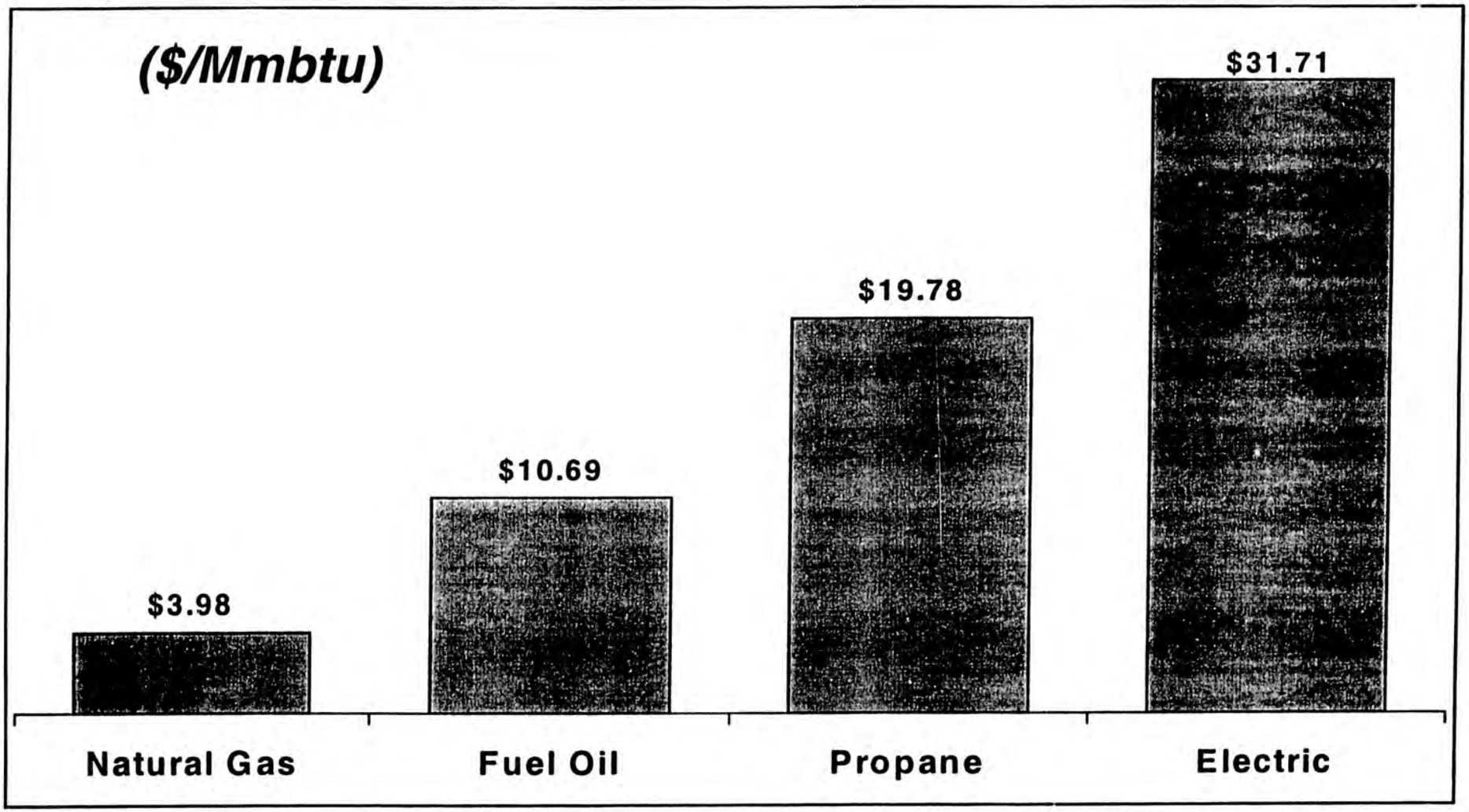
- Local Distribution Company based in Anchorage
- Commenced operation in August 1961
- Currently serve 106,800 customers
- Some of the lowest gas rates in the country
- Highest gas usage per residential customer among investor-owned utilities in U.S.

ENSTAR



ENSTAR

1 CCF is equal to 100,000 BTUs

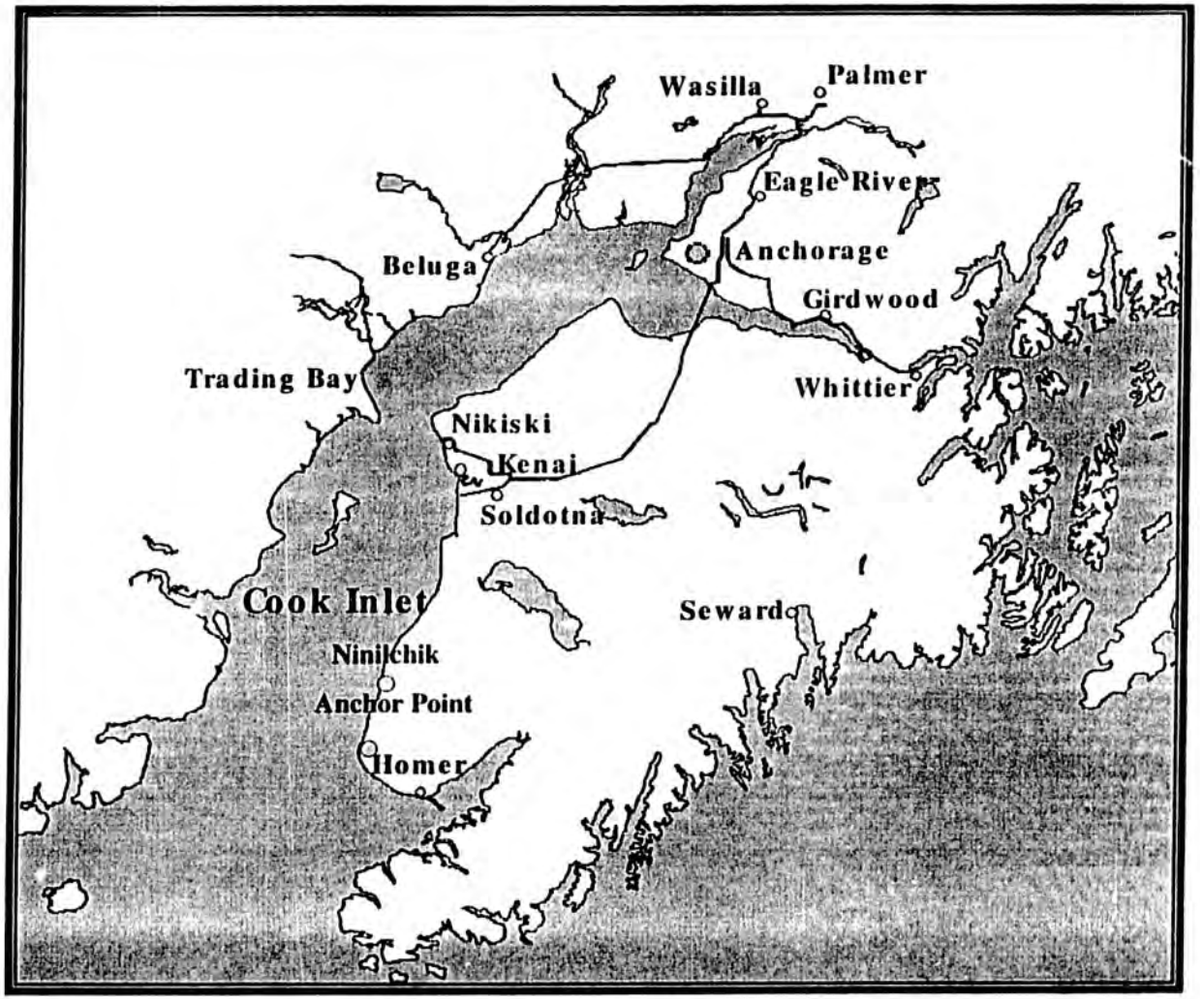

($/Mmbtu)
$3.98
$10.69
$19.78
$31.71
Natural Gas
Fuel Oil
Propane
Electric

ENSTAR

Expansion Plans

- Future plans to expand our system to Ninilchik, Anchor Point, and Homer
- ENSTAR owns and operates over 2,700 miles of Distribution and Transmission Pipeline

ENSTAR


Wasilla
Palmer
Eagle River
Anchorage
Beluga
Girdwood
Trading Bay
Whittier
Nikiski
Kenai
Soldotna
Cook Inlet
Seward
Ninilchik
Anchor Point
Homer

ENSTAR

- Company Overview
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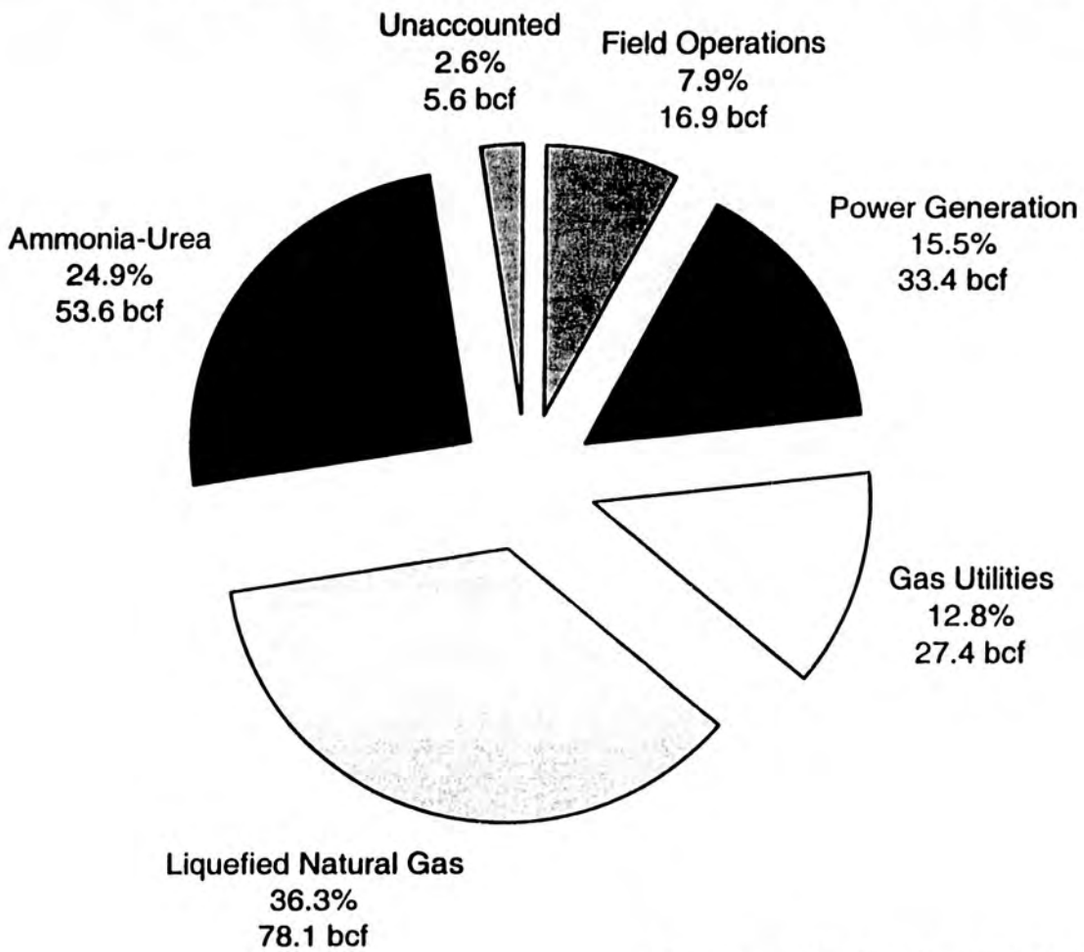
- South-central demand & deliverability

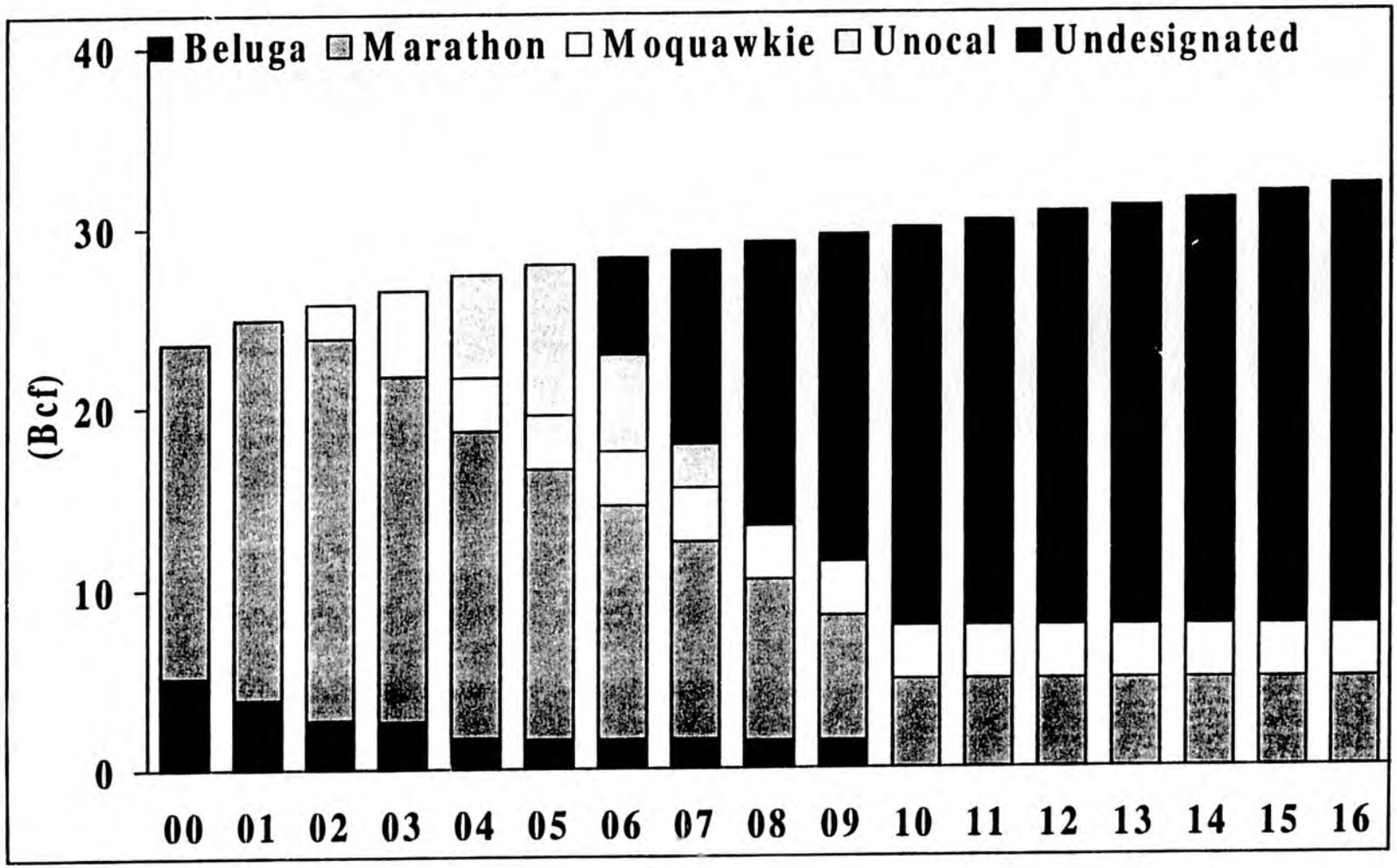
ENSTAR

Cook Inlet Historical Gas Consumption by Type, 1998



Source: DNR, Division of Oil and Gas, 2001a

ENSTAR


Beluga
Marathon
Moquawkie
Unocal
Undesignated
40
30
20
10
0
(Bcf)
00
01
02
03
04
05
06
07
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16

ENSTAR

- Gas is purchased under long-term contracts with Marathon, Chevron, ML&P, & Phillips
- Gas is indexed to changes in the price of crude oil
- Gas supply costs passed through to customers
- No take-or-pay liability
- Two new Supply Contracts
  - Moquawkie (Anadarko & Phillips) deliveries start 1/1/02
  - Unocal – deliveries scheduled to start 1/1/04
- Currently talking with producers for future supplies

ENSTAR

- Company Overview
- Projected Gas Usage
- **South-central demand & deliverability**

ENSTAR

- The Near Term [2001-2008]
- The Medium Term [2009-2019]
- The Long Term [After 2019]

ENSTAR

The Near Term [2001-2008]

- By the middle of this decade, it may be become difficult to meet winter peak demands without new discoveries or development of peaking facilities.
- Industrial usage reduction may be needed to meet winter peak demand.
- ENSTAR has entered into new supply contracts at higher prices in an effort to spur exploration and increase reserves.
- ENSTAR's new Gas Supply Contract with Unocal contemplates that gas storage will be developed.

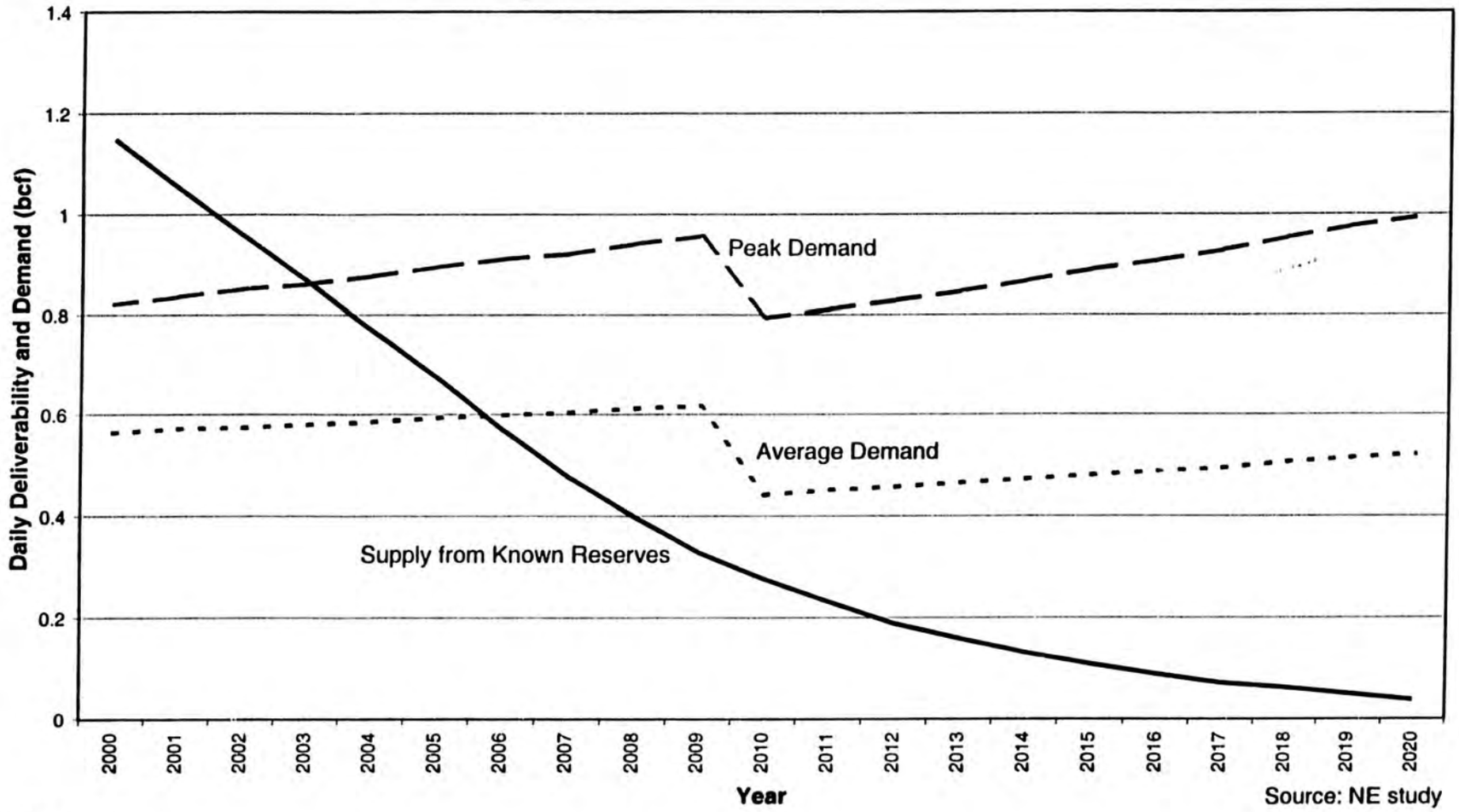
ENSTAR

The Medium Term [2009-2019]

- Peak and daily deliverability become more difficult if –
  - Approximately 2 TCF of additional reserves are not added
  - Industrial use continues after 2009
- Federal LNG license may be at risk

ENSTAR

Estimated Deliverability Timeline Assuming that Industrial Use is Reduced by Half in 2010



Source: NE study

ENSTAR

The Long Term [After 2019]

- Current natural gas reserves in Cook Inlet will most likely be unable to meet the demand of the Cook Inlet region unless –
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ENSTAR

- Cook Inlet natural gas reserves are sufficient to meet residential and commercial needs in the near term. New reserves and/or storage will improve near-term deliverability during peak demand.
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- ENSTAR supports an in-state route for North Slope Gas to ensure access to reliable low cost energy for future generations of Alaskans.

ENSTAR



Providing Alaskans with safe, clean, economical natural gas for 40 years.

ENSTAR

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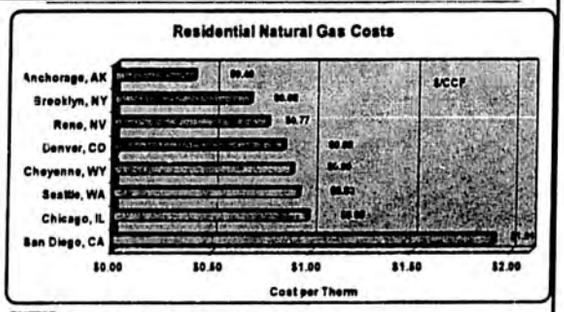
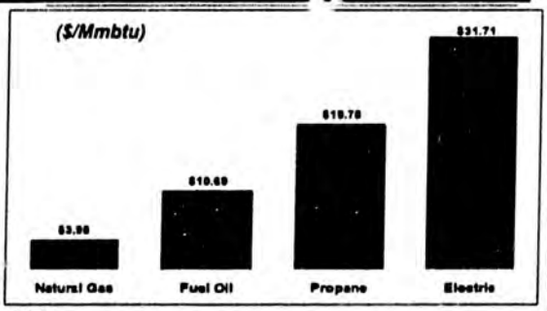
Low Residential Natural Gas Rates



1 CCF is equal to 100,000 BTUs

Lowest Average Residential Energy Costs



ENSTAR Overview

Expansion Plans

- Future plans to expand our system to Ninilchik, Anchor Point, and Homer
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ENSTAR Transmission Pipelines



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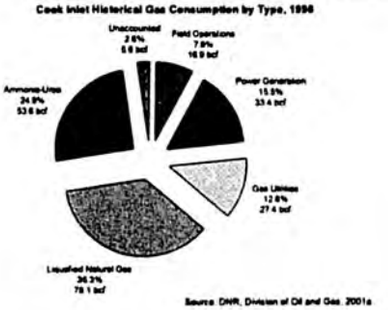
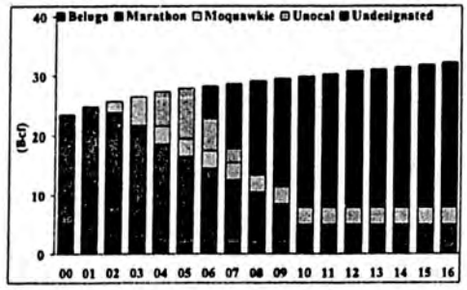
Cook Inlet Consumption



ENSTAR Projected Gas Use



Gas Supply Considerations

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Demand and Deliverability

- **The Near Term [2001-2008]**
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Demand and Deliverability

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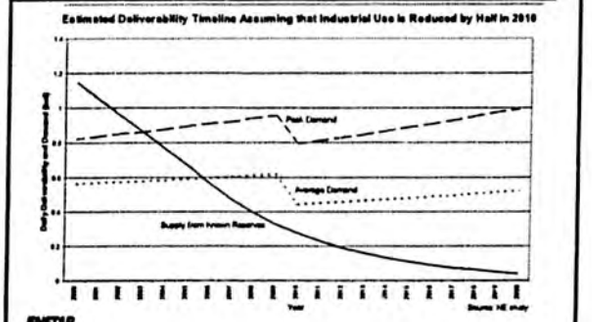
Deliverability



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In summary

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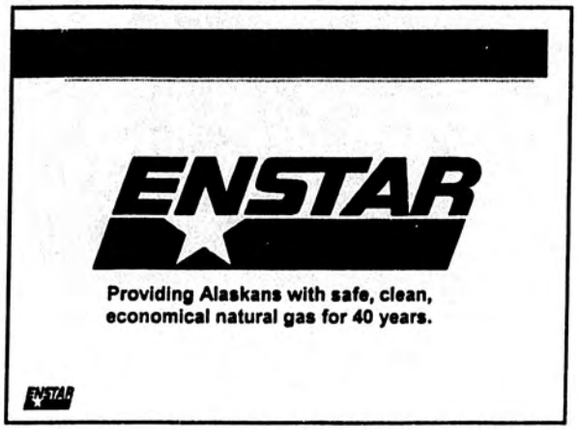
ENSTAR
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economical natural gas for 40 years.
ENSTAR

ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

TESTIMONY of JOHN ELLWOOD
EXECUTIVE VICE PRESIDENT AND
CHIEF OPERATING OFFICER

FOOTHILLS PIPE LINES LTD.

KENAI, ALASKA NOVEMBER 7-8, 2001

Alaska State Legislature Joint Committee on Natural Gas Pipelines

Mr. Chairman:

Thank you for the invitation to appear before your committee and to report on the progress of the ANNGTC/Foothills (ANGTS) Alaska Highway Pipeline project.

Foothills appeared before your committee on July 18, August 15 and September 19, 2001. During the earlier appearances we spoke to issues of the ANGTS advantages, Alaska benefits, pipeline access, status of the pipeline and the various permits. The later appearance focused on our position regarding the federal legislation proposed by the Alaska producer group.

Since that time, U.S. Senate hearings on Alaska natural gas were held in Washington and the Alaska Highway Natural Gas Policy Council forwarded its recommendations to the Governor. Foothills appreciates the efforts of policy makers involved in both of these proceedings.

Mr. Chairman, I would like at this time to express our appreciation to you and to the committee for your words and contribution to the US Senate Energy Committee hearings.

Today I would propose to report progress by Foothills on three fronts:

- The Alaska Northwest Natural Gas Transportation Company (ANNGTC) partnership.
- Foothills commercial proposal.
- Work on the pipeline right-of-way.

<u>Alaska Northwest Natural gas Transportation Company (ANNGTC)</u>

We are aware of a lingering concern regarding the so-called withdrawn partners issue and alleged liabilities associated with that issue.

When I appeared before your committee in July of this year, I indicated that Foothills had undertaken discussions to re-enlist the Withdrawn Partners of the ANNGTC.

In our testimony before the US Senate Energy Committee on October 2, 2001, Foothills said:

> "In the initial stages of the Alaska Highway Project, numerous U.S. energy companies were partners in the Alaska Partnership. However, during the decade of the 1980s and the 1990s when the producers of Alaska natural gas were unwilling to commit that gas to Lower 48 markets because of low energy prices,

all of the U.S. partners withdrew from the Alaska Partnership. Foothills and TransCanada, as the two remaining partners, have offered to the current holders of the withdrawn partner interests an opportunity to rejoin the Alaska Partnership. The negotiations with these companies have been productive and are ongoing"

Last month we followed-up our testimony with a letter expanding on the re-enlistment process.

> " Earlier this month we testified before the Committee on Energy and Natural Resources regarding our efforts to reconstitute the Alaska Northwest Natural Gas Transportation Company (Alaska Partnership) by re-enlisting the withdrawn partners. We are writing today on behalf of TransCanada and Foothills, and, with the authorization of the withdrawn partners – Duke, El Paso, Enron, PG&E Corporation, Sempra and Williams specifically with respect to the re-enlistment process. We are pleased to report that continued progress has been made on the critical issues, including the key principles for re-enlistment by any withdrawn partner who so elects in the Alaska Partnership, for the purpose of constructing the Alaska Natural Gas Transportation System (ANGTS).
>
> We have already scheduled further meetings so that we can continue to work on the details for reconstituting the Alaska Partnership. It is anticipated that all parties will have signed a Memorandum of Understanding (MOU) within the next month. TransCanada, Foothills and the withdrawn partners are committed to eliminating commercial barriers to construction of the ANGTS and in so doing would be prepared to release contingent claims against the Alaska Partnership related to previous investments in the ANGTS as part of a commercial arrangement to ensure a market viable project."

Our negotiations with the withdrawn partners are approaching the final stages and we are confident of meeting our timeline for the successful conclusion of an agreement..

Commercial Proposal

A commercial agreement with the Alaska producers is an important prerequisite to any pipeline project.

Achieving such an agreement has been delayed, in part, because of the withdrawn partnership issue overhanging the project, and because the Alaska North Slope are focused on completing their project feasibility study.

In our October evidence before the US Senate Energy Committee, we said:

> "An important first step towards commercial viability of an Alaska gas pipeline is a commercial agreement between the producers and potential shippers who, in turn, enter into transportation contracts with the owners and operators of the transportation system. In this regard, the Alaska Partnership has pursued discussions with the producers for the last several months. After several

> discussions with the producers over the last year, it has been agreed that we will develop a commercial proposal to present to the producers before the end of the year."

The above referenced October testimony also stated:

> "The next step on our critical path will be to prepare, present to, and negotiate with the producers of Alaska North Slope natural gas a comprehensive commercial proposal for a pipeline project. Based on the progress we have made since the Energy Committee hearings, we are confident that such a proposal will be presented to the producers before the end of the year. As companies with long-standing interest in building and owning an Alaska natural gas pipeline, we have every incentive to reach a commercial arrangement with the producers to develop a viable project. We believe that such an arrangement will be achieved on a timely basis, consistent with the energy needs of the Nation."

With regards to the negotiations with the North Slope Producers, we remain confident that we will reach a commercial arrangement to develop a viable project.

Pipeline Right-of-Way

The Alaska Natural Gas Transportation System from Prudhoe to Alberta is approximately 1,750 miles long.

Access to land is becoming a difficult challenge for all North American pipeline projects. Public lands constitute the majority of the property through which the pipeline will pass.

Foothills is well advanced along the road of securing the pipeline right-of-way. More than 400 miles of right-of-way on federal lands has been acquired. Currently, we are making progress on securing the 200 miles of right-of-way on State lands with the Gas Pipeline Office. Work is under way to assess the information that was previously submitted in an earlier application, and a process to move forward has been identified. With the State right-of-way lease expected to in hand by2003, over 90% of the right-of-way for the project will have been acquired or reserved.

Let's summarize the progress of the Alaska Highway Pipeline project.

1. The United States and Canada have determined that the ANNGTC/Foothills (ANGTS) Alaska Highway Pipeline project is:

   (a) Necessary.
   (b) In the public interest.
   (c) Should be granted a unique fast track status.

2. Foothills and TransCanada have offered to the current holders of the withdrawn partner interests an opportunity to rejoin the Alaska Partnership. Negotiations have been productive and we are well on our way to re-assembling the Alaska Partnership.

3. A commercial arrangement between a coalition of North American pipeline companies and an Alaska natural gas producer group is the next key milestone. We are working towards that end.

   - A commercial arrangement will allow the project to move to the next phase of the project ... "the countdown to construction" phase.

   - A substantial amount of this work has already been completed and more is currently being done "on spec" to further expedite this stage of the project.

4. As I indicated, we have made substantial progress in the area of pipeline right-of-way.

5. In moving forward we will comply with the technical and environmental conditions established by President Carter when he approved our project. In doing so we intend to work with interested stakeholders. Over the coming months we will take steps to establish a consultation process that will enable interested Alaskans to become involved in the project.

6. We are committed to maximizing Alaska benefits consistent with prudent economic efficiencies. The Governor's Policy Council has made reasonable recommendations in this regard.

Ultimately the final decision to construct a pipeline will rest with the gas producers. We remain confident that the long-term demand for and the price of natural gas in the North American markets will support this project.



November 8, 2001

The Honorable John Torgerson
Chair, Joint Committee On Natural Gas Pipelines
Alaska State Legislature
35477 Kenai Spur Highway, Suite 101A
Soldotna, Alaska 99669

Senator Torgerson:

Thank you for the opportunity to address your committee relating to a GTL project for the North Slope and on issues of gas supply and demand for Cook Inlet natural gas.

I would like to make a few comments about U.S. energy independence in light of the September 11th terrorist attack on the US.

I have long been a proponent of GTL's as one solution for Alaska's stranded natural gas and coal based GTL's as one answer for reducing US dependence on foreign crude imports. Many others are interested in the prospects of GTL's but are waiting for some sign from the Federal and Alaskan Governments that they are willing to support GTL programs.

If the US wants a National Energy Policy to reduce its dependence on foreign crude oil it can to look to the example of the South African's. South Africa pioneered coal gasification - gas to liquids in the 50's and expanded the program in the 70's when OPEC boycotted the US in order to reduce its imports of foreign crude.

Today with advances in GTL technology, the US can build more efficient gasification - GTL plants for far less than what it cost South Africa. The US has enough coal reserves in 38 states across the nation to make over 10 million barrels per day of synthetic motor fuels for over 200 years.

The Alaskan North Slope contains enough natural gas to make a 1 million barrels per day of synthetic fuels that can be transported down the existing crude oil line to Valdez for shipment to the lower 48. Of importance also is that a GTL batching program will

ANGTL's proposal can result in the US, replacing up to 25% of its "dirty" diesel with this new clean burning fuel. The existing crude oil refiners don't want that to happen because it will cost them money.

Each year US refiners cite lack of domestic refining capacity to meet the summer driving needs as justification to raise the price of gasoline and diesel 25¢ to 35¢/gallon. An Alaskan GTL program could end this US refining short fall, resulting in $billions less to the oil companies.

F-T produced GTL's are odorless, non-toxic and completely biodegradable on land or water according to the US EPA. The $3+ million cost to clean up of the diesel spill from the fishing boat Windy Bay in Prince Williams Sound this past August could have been a non event.

Alaska can become a major producer of these ultra clean fuels if it so chooses, but it will take tremendous pressure from the people and environmental community to make it happen. Alaska has enough existing natural gas to make upwards of 1 million barrels per day of these ultra clean fuels and enough capacity in the existing oil pipeline to transport these fuels; plus develop ANWR.

America is not as short of clean energy as we are critically short of a comprehensive energy policy that can wean us off foreign crude and products.

There are many misconceptions about an Alaskan GTL program and about GTL's in general.

Too many BTU's are wasted

Natural gas from the North Slope must be converted into useful energy by some process. Home heating, electric generation, transportation fuels, industrial processes. None are 100% efficient. Most industrial processes, including electric generation are at best 50% efficient. Did you know that the gas turbines used to generate electricity are only about 40% to 50 % efficient.

The truth is that the actual GTL conversion process converts approximately 70% of the natural gas BTU into synthetic fuels. If you capture the "waste" heat for electric generation, the CO2 for enhanced oil recovery and process water to reduce energy consumption, you end up converting more BTU's in the natural gas to useful products.

Of course the finished products from the GTL process are for the most part more valuable than natural gas, certainly from a National Energy Policy point of view.

There is enough Natural Gas on the North Slope for several projects.

The truth is that a 4 BCF/D gas line will need at least 36 TCF. No other project can be financed until gas producers "prove" up additional reserves. While it is easy to say the North Slope contains 50 to 100 TCF of gas reserves, until they are "proven" no other project can be financed and built. A .5 to 1 BCF/D GTL project that can be economically done TODAY still leaves enough gas for a

Gas to liquid plants are very expensive but will produce environmentally superior natural gas based "alternative" fuels for the motor fuels market. It is important to note that GTL's are NOT petroleum based. Compressed natural gas (CNG), is also an "alternative" fuel for use in the motor fuels market. Under existing motor fuels tax schedules, CNG is taxed at a lower rate than petroleum based motor fuels. If GTL's, which are also natural gas based like CNG, are taxed at the same rate as CNG, then the GTL producer will keep up to $13/bbl more of the price collected for its fuel at the pump resulting in a higher net-back to the well head and an acceptable rate of return on the plant investment. This is not additional Federal and State support, it is being taxed at the same rate as other natural gas based alternative motor fuels.

One Major Oil company claims that any form of Federal "subsidy" is unacceptable and sends the wrong signals to the market. This same oil company gladly accepted an exemption to the "wind fall profit tax" for their Alaskan crude to help pay off their "expensive" Alaskan oil line. Are these majors willing to accept subsidies when they help them, but unwilling to allow them if they help others and reduce US dependence on foreign crude oil?

Now I would like to move on the Cook Inlet / Kenai area.

The ANGTL Company is looking at two different GTL programs in the Cook Inlet area. They are for the most part mutually exclusive in that natural gas price and availability will dictate which direction we go.

Some believe that the Cook Inlet area is short on natural gas and the long term outlook is for limited resources and higher natural gas prices well in excess of $2.50 to $3.00 / mcf. Still others believe that the region has vast supplies of natural gas but little or no new market demand for base load supplies to warrant much additional exploration.

In the scenario of abundant gas supply in the Cook Inlet area - $2.00 or under gas prices.

ANGTL has proposed to contract with several Cook Inlet producers to purchase up to 70,000 mcf/d of natural gas (25 bcf/yr) for a minimum of 12 years (300 bcf) and preferably 25 years (640 bcf) to base load a GTL plant built adjacent to the Tesoro and Agrium facilities on the Kenai. Based upon a preliminary engineering study preformed by Dresser Engineering, the estimated plant cost should be in the $250 million dollar range for a 8,500 bbl/d plant. The limiting plant size is the availability of the natural gas feed stock.

The natural gas will be sold to the plant on a net back basis determined by the revenues received from the sale of the different products. As you know the GTL plant produces excess hydrogen and nitrogen, two of the primary feed stocks for the fertilizer plant. The GTL plant plans to will export these feed stocks to the fertilizer plant for incremental ammonia and urea production. Thus potentially lowering the overall cost of the fertilizer plant, improving the economics of the plant and its ability to pay market value for natural gas while competing in an export products market.

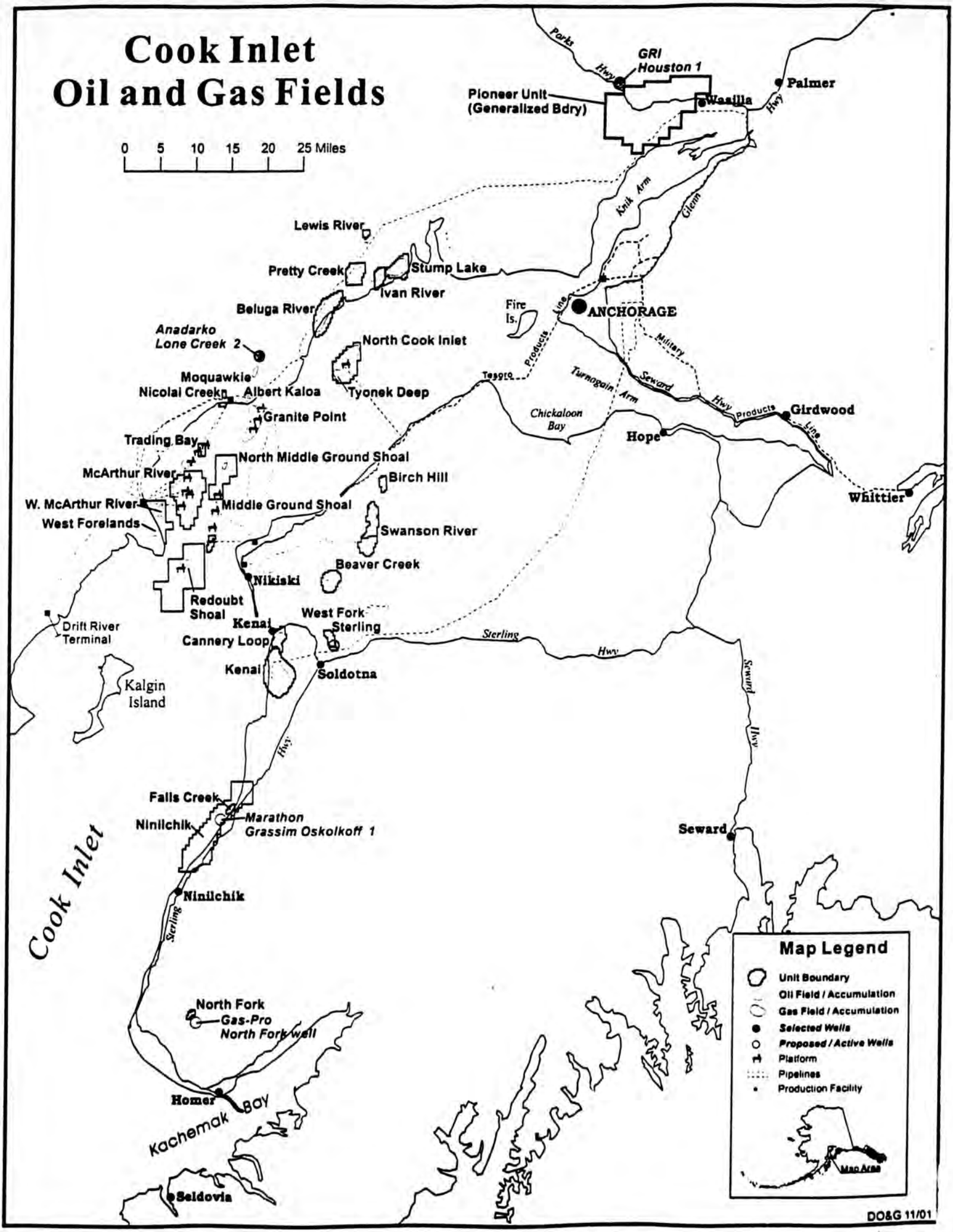
Presentation to the Joint Committee on Natural Gas Pipelines

Bill VanDyke, Petroleum Manager
Tim Ryherd, Geologist
Will Nebesky, Commercial Analyst

Alaska D.N.R. - Division of Oil and Gas
November 8, 2001

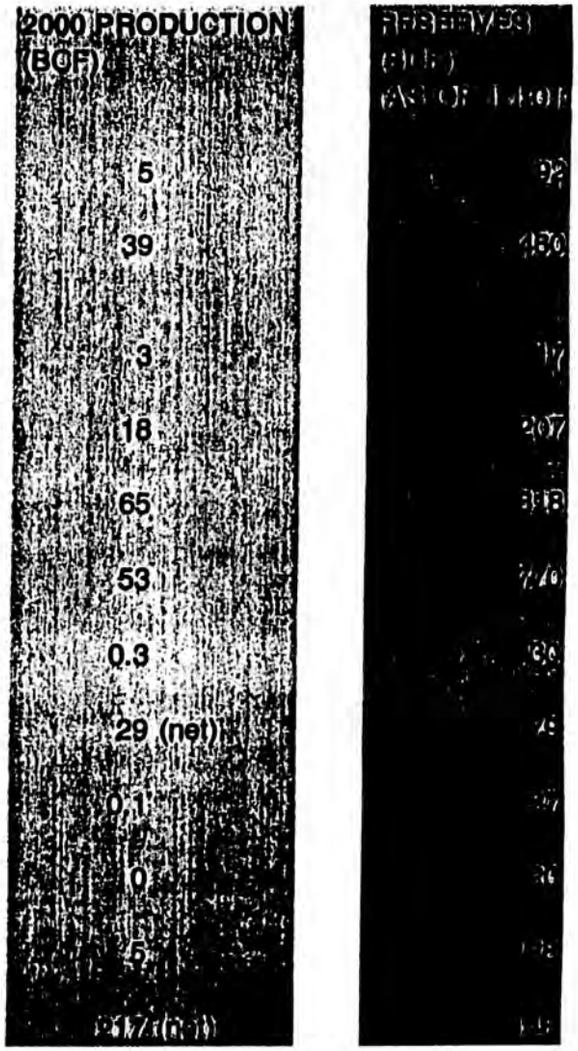
Alaska Department of
Natural
Resources

http://www.dog.dnr.state.ak.us/oil/index.htm


Cook Inlet
Oil and Gas Fields
0 5 10 15 20 25 Miles
Parks Hwy
GRI
Houston 1
Pioneer Unit
(Generalized Bdry)
Wasilla
Palmer
Hwy
Knik Arm
Glenn
Lewis River
Pretty Creek
Stump Lake
Ivan River
Beluga River
Fire Is.
ANCHORAGE
Anadarko
Lone Creek 2
North Cook Inlet
Moquawkie
Nicolai Creekn
Albert Kaloa
Tyonek Deep
Granite Point
Trading Bay
North Middle Ground Shoal
McArthur River
Birch Hill
W. McArthur River
Middle Ground Shoal
West Forelands
Swanson River
Beaver Creek
Nikiski
Redoubt
Shoal
Kenai
West Fork
Sterling
Drift River
Terminal
Cannery Loop
Kenai
Soldotna
Kalgin
Island
Sterling Hwy
Falls Creek
Ninilchik
Marathon
Grassim Oskolkoff 1
Cook Inlet
Ninilchik
Sterling
North Fork
Gas-Pro
North Fork well
Homer
Bay
Kachemak
Seldovia
Products Line
Tesoro
Turnagain Arm
Military
Seward
Hwy
Chickaloon
Bay
Hope
Girdwood
Products Line
Whittier
Seward
Seward Hwy
Map Legend
Unit Boundary
Oil Field / Accumulation
Gas Field / Accumulation
Selected Wells
Proposed / Active Wells
Platform
Pipelines
Production Facility
Map Area
DO&G 11/01

Cook Inlet Gas Production and Reserves

FIELD NAME	2000 PRODUCTION (BCF)	
BEAVER CREEK	5	
BELUGA RIVER	39	
IVAN RIVER, STUMP LAKE, PRETTY CREEK, LEWIS RIVER	3	
KENAI, CANNERY LOOP	18	
MCARTHUR RIVER	65	
NORTH COOK INLET	53	
STERLING	0.3	
SWANSON RIVER	29 (net)	
TRADING BAY	0.1	
WEST FORELAND	0	
ALL OTHERS	5	
TOTAL		



WVD
DNR/DO&G
NOV. 8, 2001

Gas Hypothetically Available for Local Utility Use

	ASSUMED DATES GAS USERS CEASE OPERATIONS			
GAS USER	**SCENARIO 1**	**SCENARIO 2**	**SCENARIO 3**	**SCENARIO 4****
AGRIUM	2005	2010	2015	2015
LNG	2009	2009	2015	2015
OIL FIELD OPERATIONS	2009	2015	2015	2015
GAS REMAINING FOR UTILITY USE (BCF)	**1060**	**690**	**-100**	**900****
YEARS OF SUPPLY FOR UTILITY USE	**17**	**11**	**0**	**15****

NOTES:

1) THESE SCENARIOS ARE HYPOTHETICAL.
2) ASSUMED SHUT DOWN DATES ARE NOT BASED ON ACTUAL GAS SUPPLY OR ECONOMIC REALITIES.
3) GAS REMAINING FOR UTILITY USE IS BASED ON CURRENT RESERVE AND USE ESTIMATES.
4) YEARS OF UTILITY SUPPLY BASED ON CURRENT UTILITY CONSUMPTION RATES.
5) POTENTIAL FUTURE GAS DELIVERABILITY CONCERNS ARE IGNORED.

****SCENARIO 4 ADDS AN ASSUMED 1000 BCF OF YET-TO-BE DISCOVERED GAS.**

WVD
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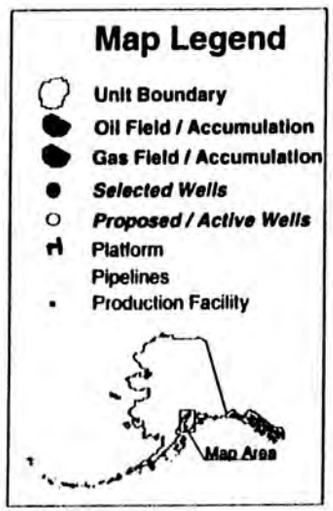
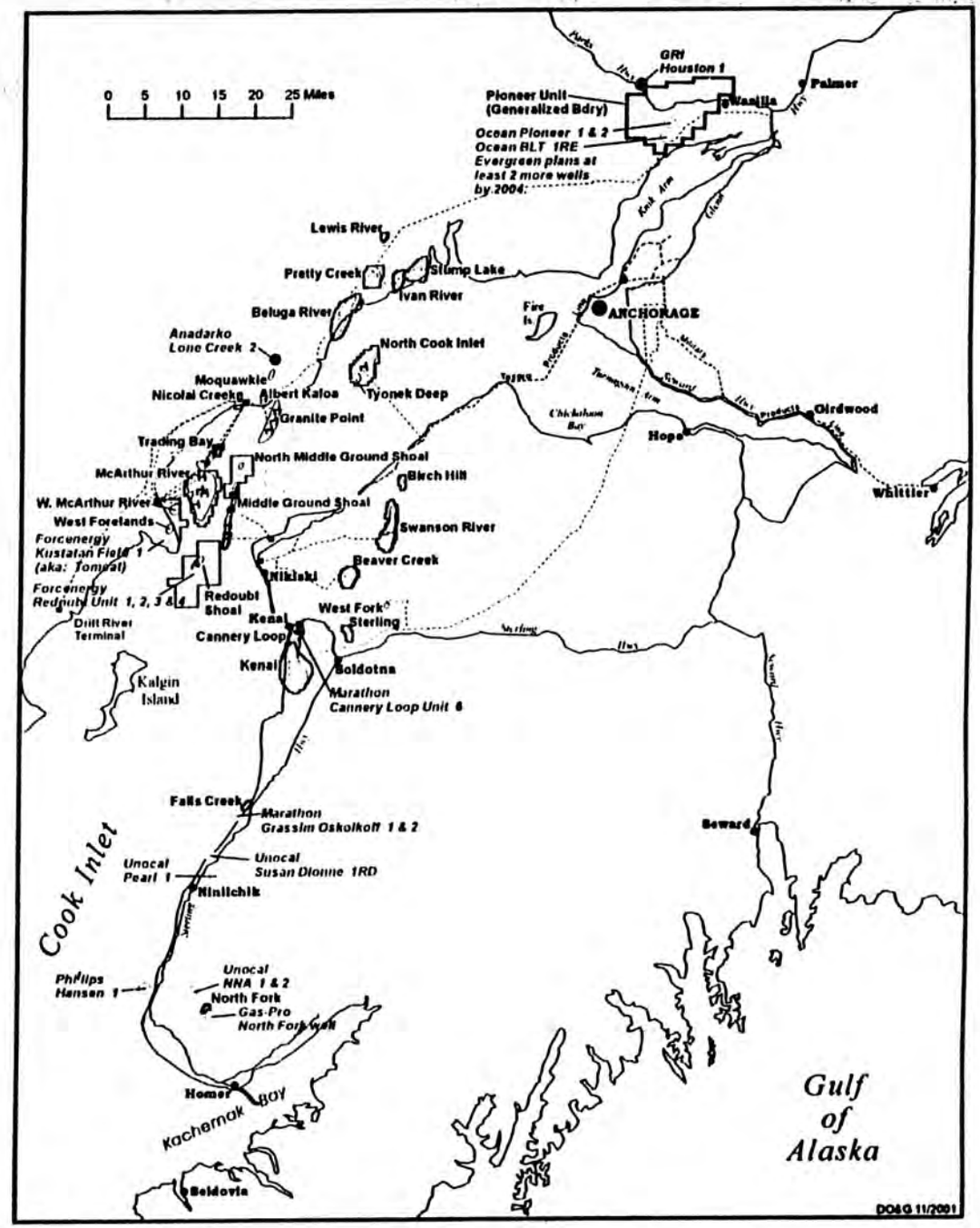
NOV. 8, 2001

Cook Inlet Activity





tjr 11/2001

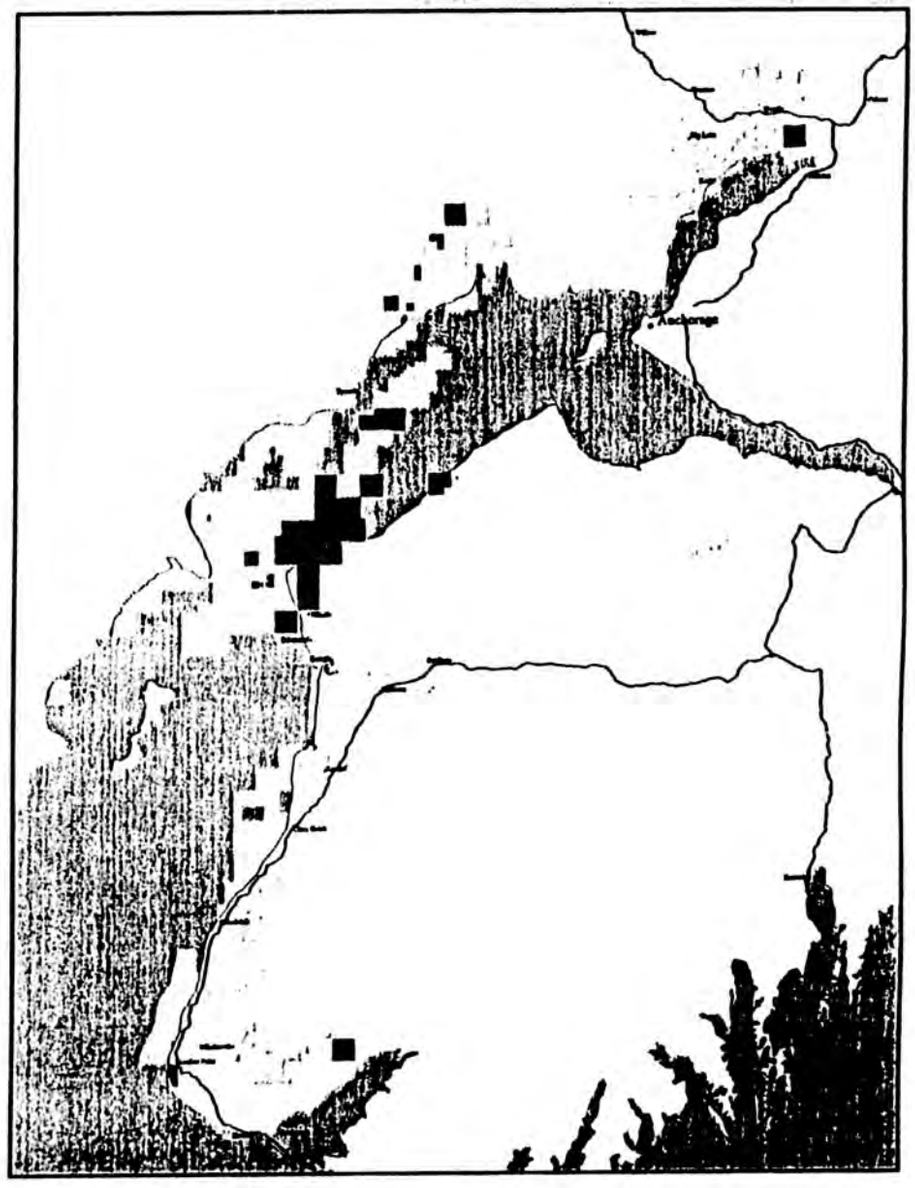
Cook Inlet Exploration Summary – 2001

- Ninilchik Unit and Falls Creek Unit – Marathon (Gas)
  - G.O. #1 well completed as gas well, G.O. #2 well planned
- South Ninilchik Unit and Deep Ck. Unit – Unocal (Gas)
  - Possible State/CIRI joint administration, up to 3 wells planned for 2001-02
- Pretty Ck./Lewis Riv./Ivan Riv. – Unocal (Gas)
  - Re-entered 1 well each in Lewis Riv. and Ivan Riv., drilling P.C.U. #4, new well, in Pretty Ck. field
- Swanson River Unit Gas Satellites Project – Unocal (Gas)
  - Proposal to develop two gas fields north and east of Swanson River oil field on Federal and Native owned lands
- Redoubt Unit – Forest Oil (Oil discovered in 1968 by Pan Am)
  - R.U. #1, #2, & #3 wells completed by Forest, R.U. #4 is planned
  - Field is bigger than originally thought, up to 193 MMBO recoverable reserves
  - Forest has other prospects at Sabre, Corsair, and Valkyrie
- Pioneer Unit – Evergreen Exploration (Coalbed gas, no proven reserves)
  - Formerly operated by Ocean Energy, ownership and operations transferred to Evergreen in mid-2001.
  - 2 production wells & 1 injection well drilled in 1999; committed to drill 6 more wells, at least 1 in each of 2 new areas
- Cosmopolitan Unit – Phillips (Oil discovered in 1967 by Penzoil)
  - Hansen #1 well permitted to drill to bottom location on State lease
- Nikolai Ck. Unit – Aurora Gas (Gas)
  - Production started in Oct., NCU #3 well produces at rate of 2 MMCF/day
- North Fork Unit – Gas Pro (Gas)
  - Project apparently on hold
- Trading Bay Unit/McArthur River Field – Unocal (Oil)
  - T.B.U. #K-13 came on production at 7,100 BOPD, highest rate of any well in Cook Inlet

Cook Inlet Areawide 2001
Sale Results

Currently Leased Acreage

Cook Inlet Areawide 2001 Leases



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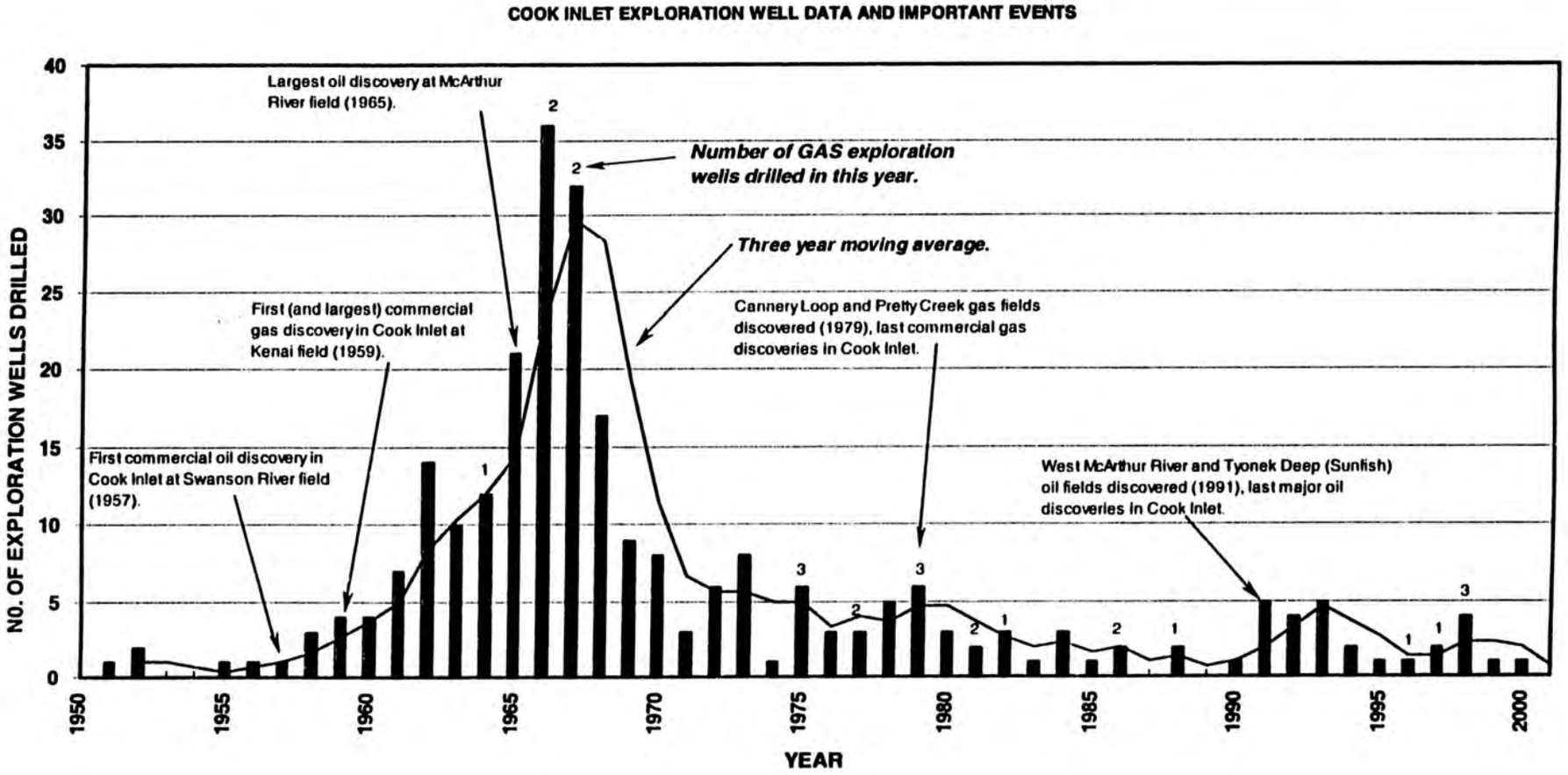
Timeline of Cook Inlet Exploration



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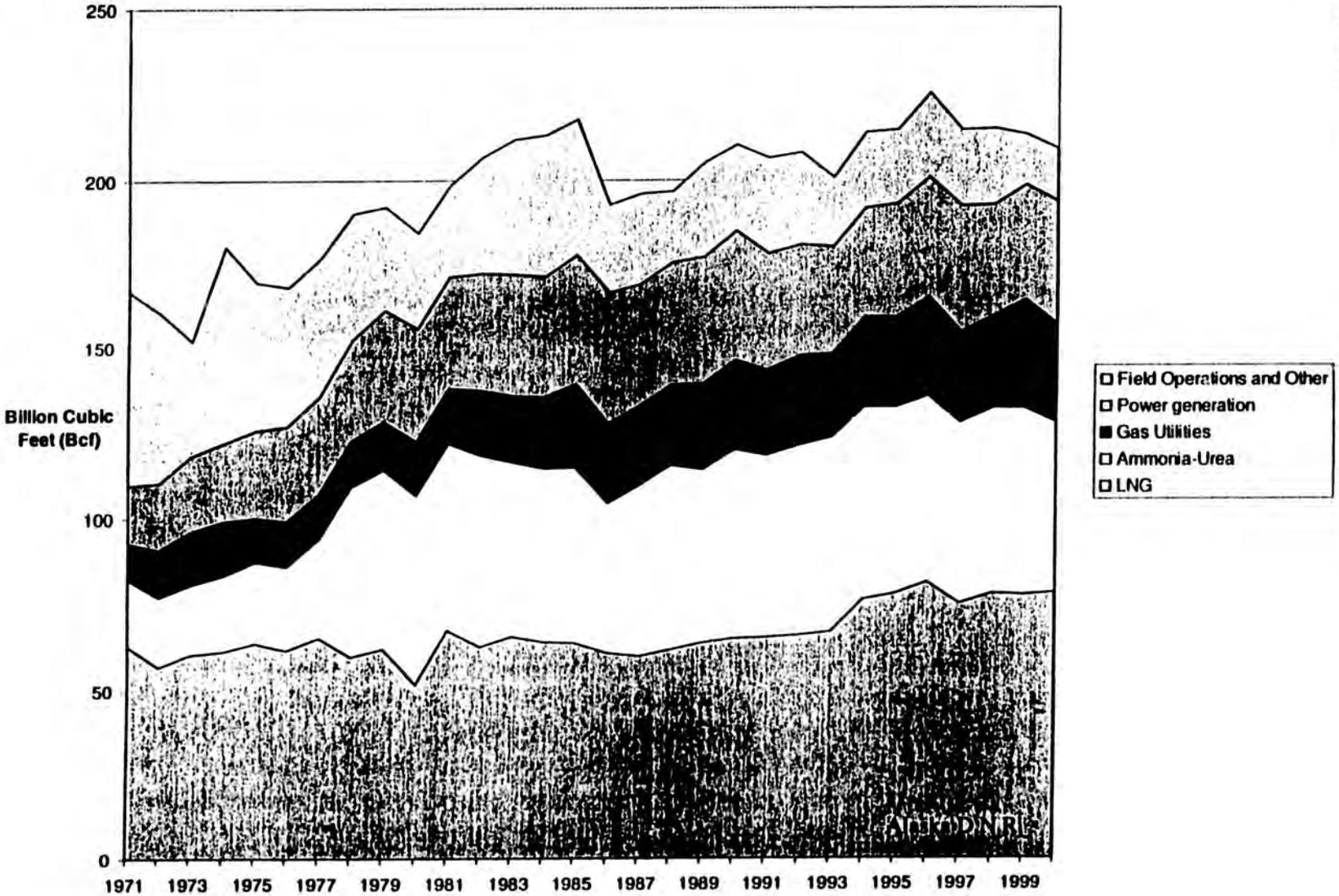
Cook Inlet Gas Exploration History

- 267 oil & gas exploration wells drilled in CI through 2000
  - Of these, 24 were GAS exploration wells
- Of largest 10 CI gas fields (based on current gas reserves), only Cannery Loop (smallest of the 10) was found by exploring FOR gas
- Much of Cook Inlet basin area is underexplored

Outlook and Predictions For Cook Inlet

- Areawide sales make entire area available for exploration and development
- Independents will become an increasing influence
  - More competition for prospects and leases
  - New thinking and inventive technology and business climate
- Independents will drive exploration and development costs lower
  - This may mean less money for the State of Alaska, as well as service companies
- Oil continues to be an elusive target in Cook Inlet
- Conventional gas exploration will extend beyond the core developed areas
- Coalbed gas will continue as an emerging exploration target
  - Viability of this exploration play is yet to be determined

Cook Inlet Historic Gas Consumption by Major Disposition Category
1971 - 2000



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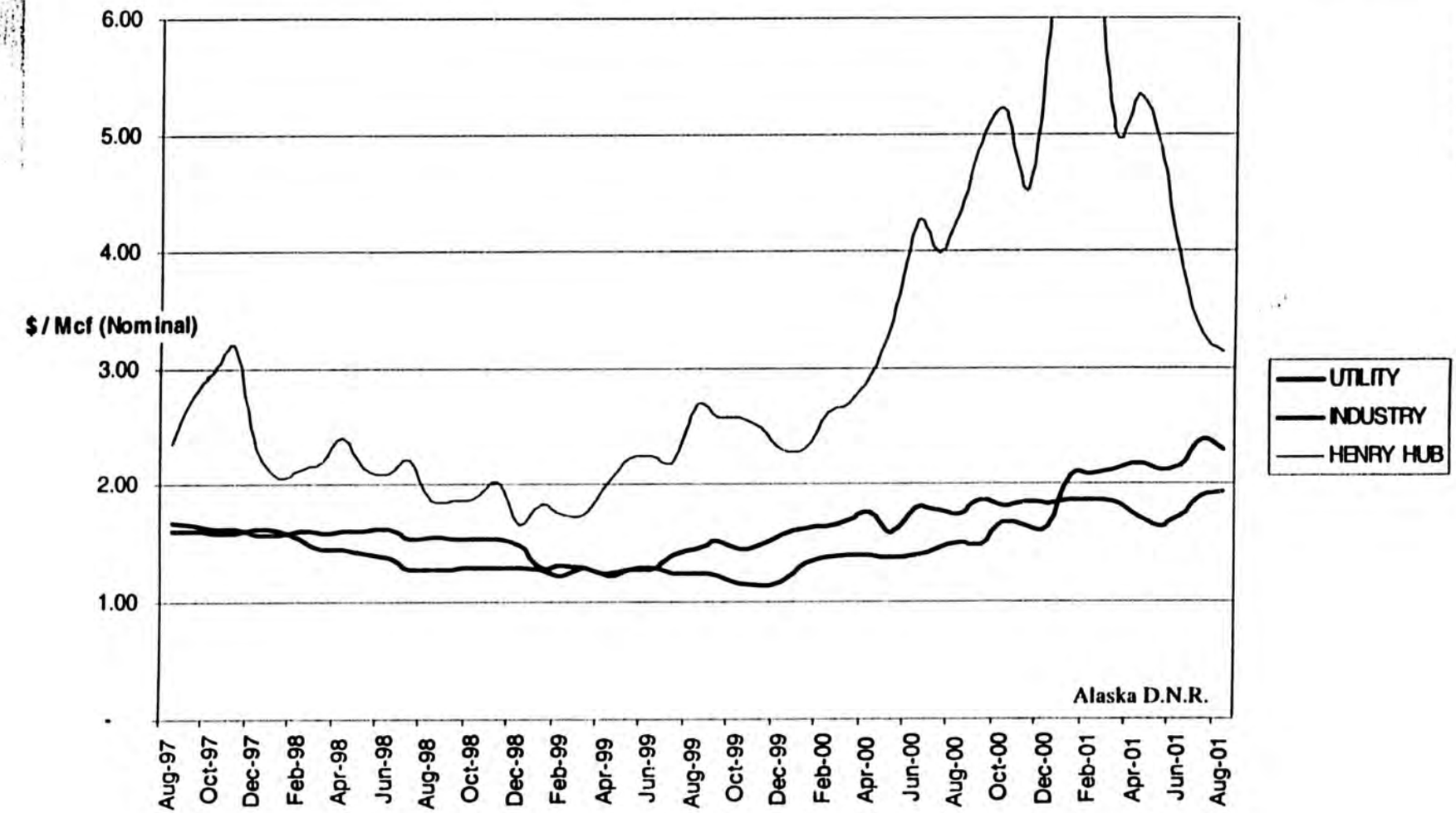
Royalty Value for Natural Gas Utility and Industry Dispositions in Cook Inlet Versus Henry Hub Spot Price Aug 1997 - Aug 2001



Utility = Electric and Space Heat.
Industrial = Urea, LNG, and Field Operations.
Henry Hub located at U.S. Gulf of Mexico.

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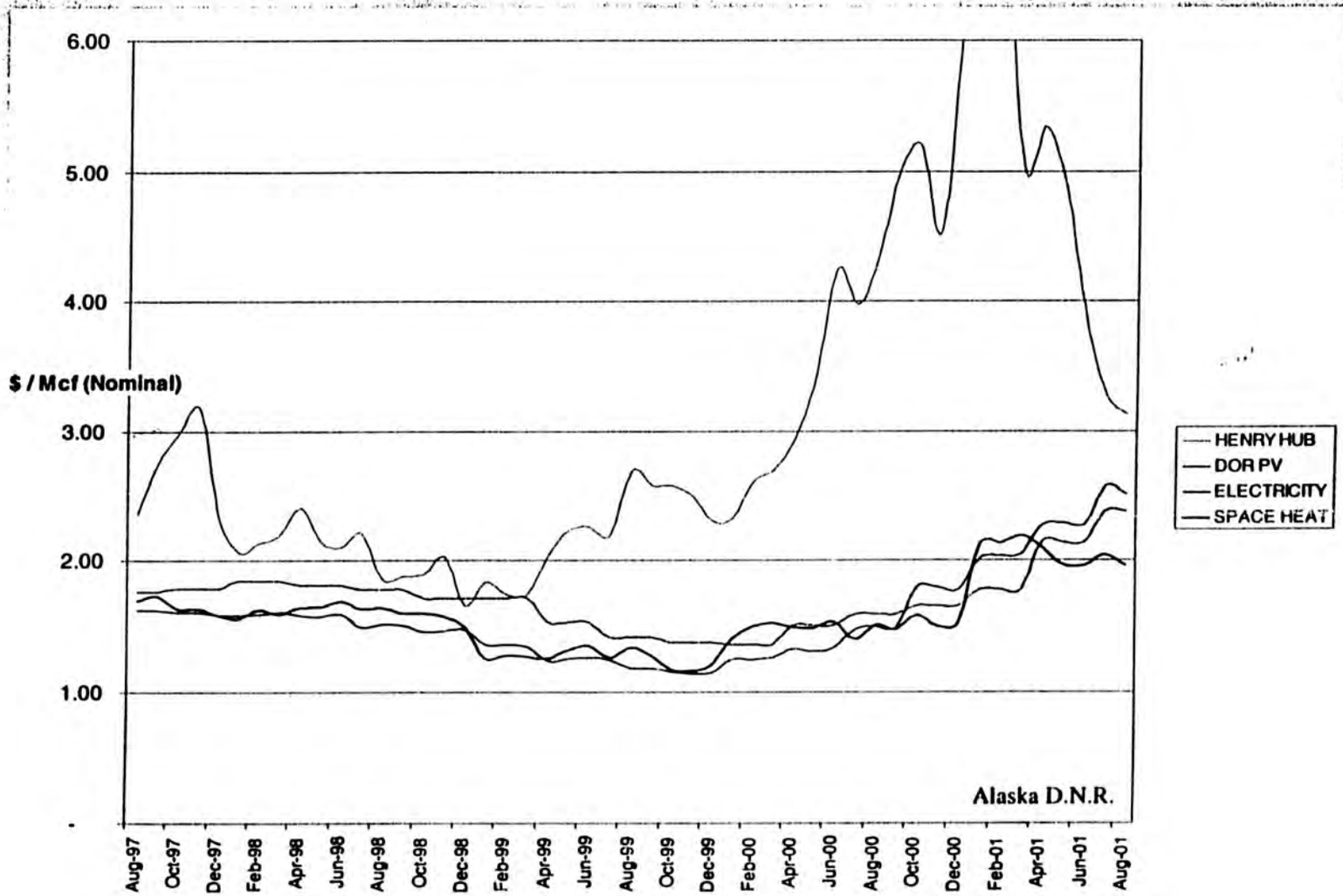
Royalty Value for Electricity and Space Heat Dispositions in Cook Inlet Versus Henry Hub Spot Price Aug 1997 - Aug 2001



Electric = CEA and MLP.
Space Heat = Enstar, Aurora, and Other LDC Direct Sales.
DOR PV for CEA, MLP, and ENSTAR.

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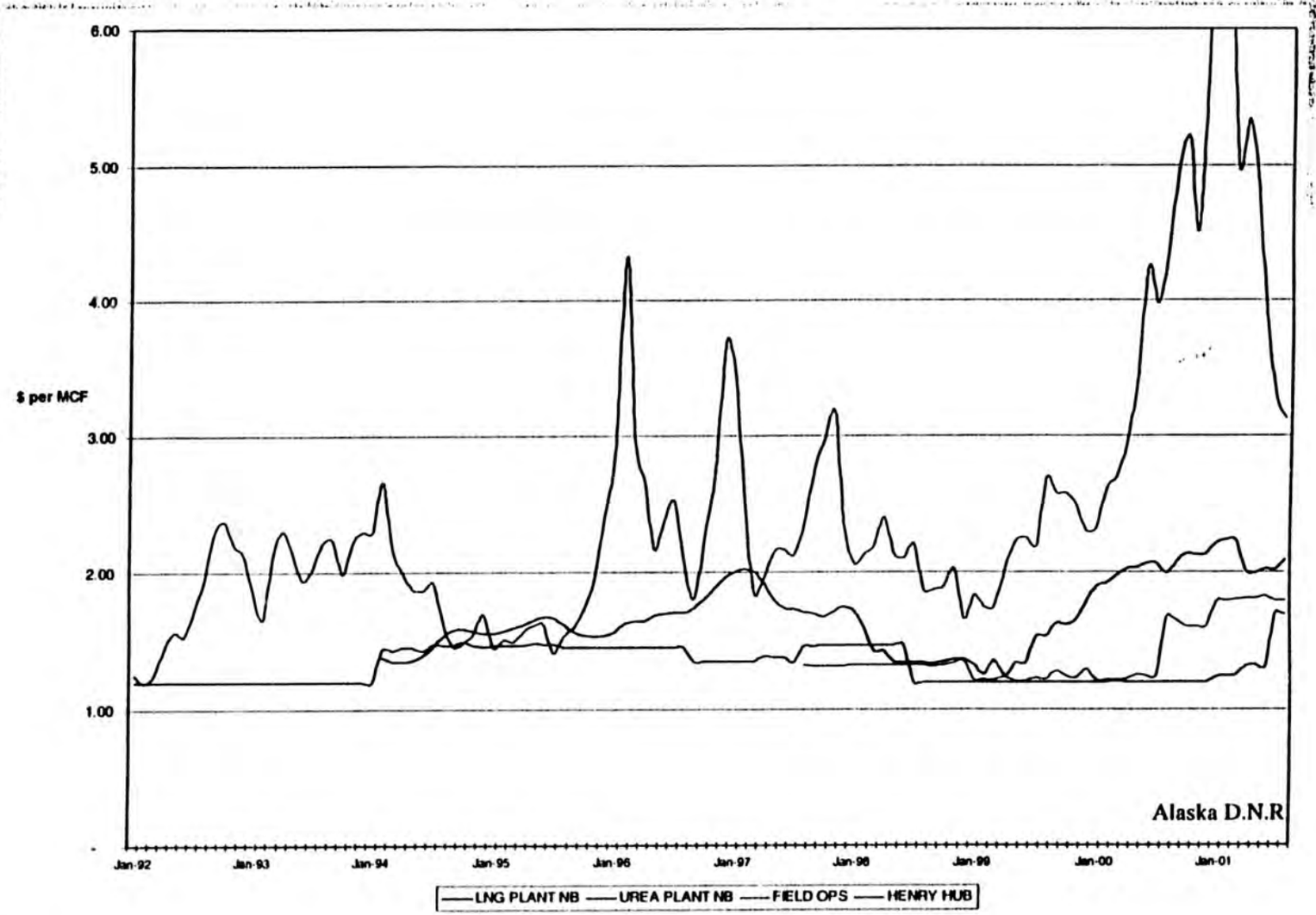
Royalty Values for Urea Plant, LNG and Field Operations Gas Dispositions in Cook Inlet Versus Henry Hub Spot Price
Jan 1989 - Aug 2001



Note: Royalty Values are Netted Back to the Wellhead.

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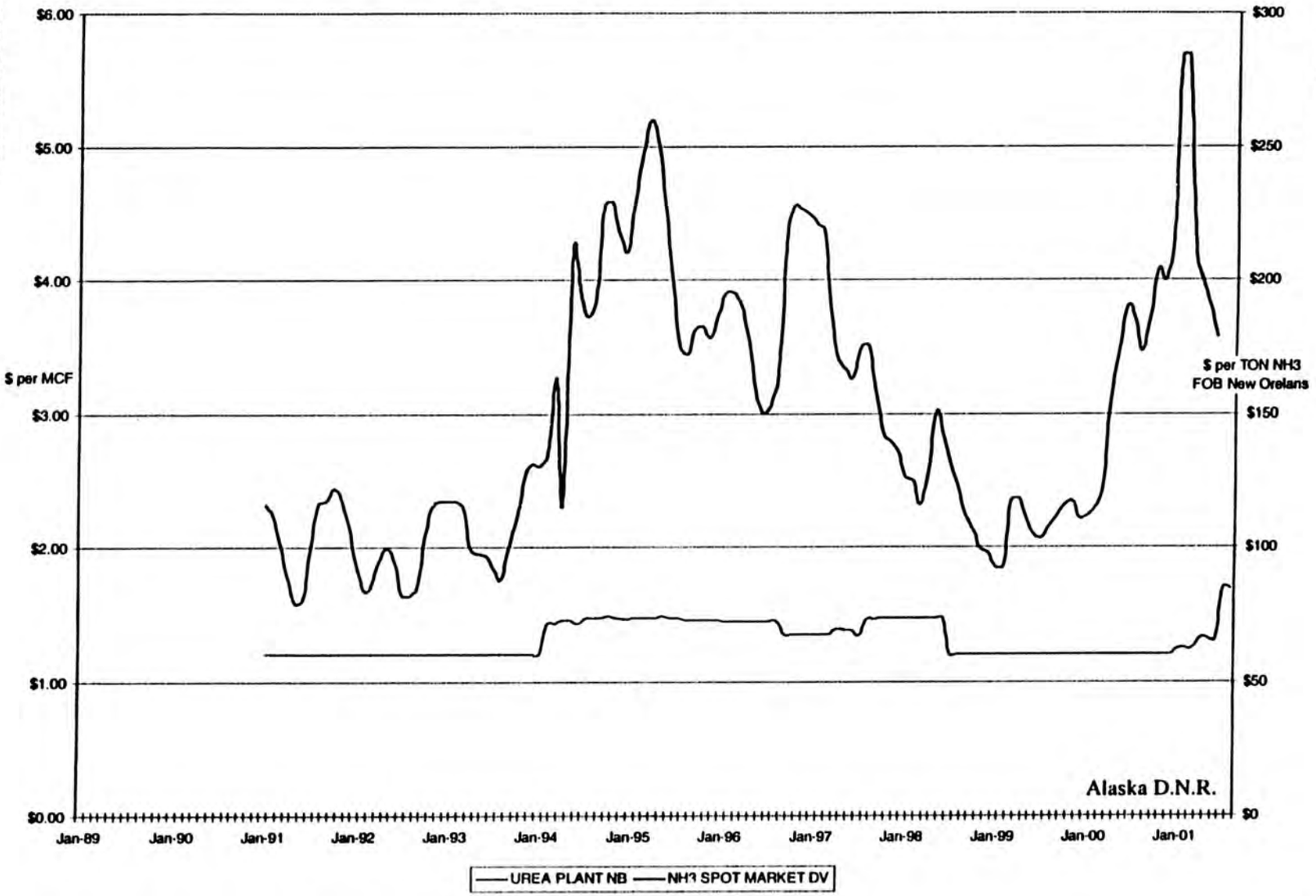
Destination and Royalty Values for Ammonia-Urea Plant Dispositions in Cook Inlet
Jan 1991 - Aug 2001



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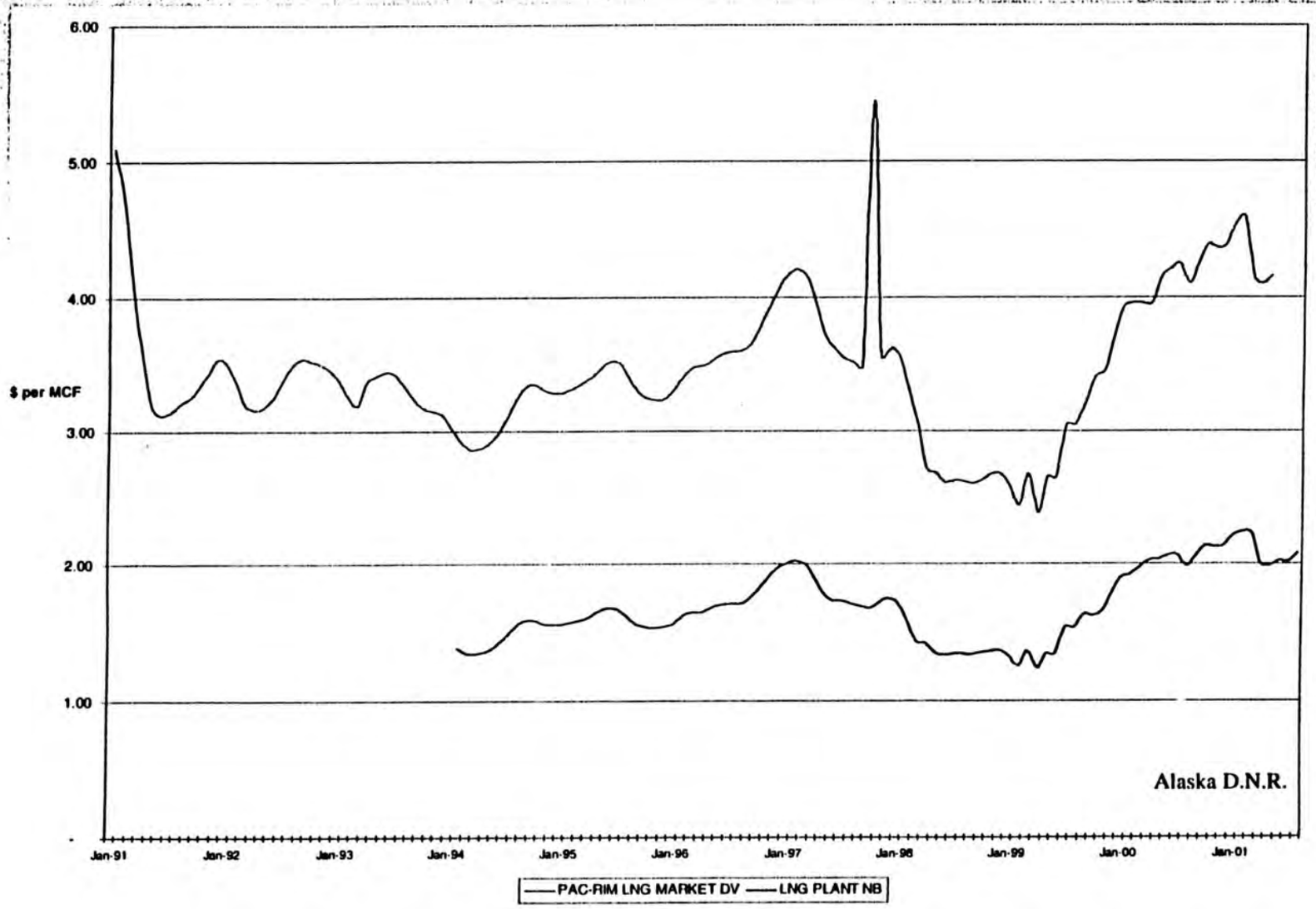
Destination and Royalty Values for LNG Gas Dispositions in Cook Inlet
Jan 1991 - Aug 2001



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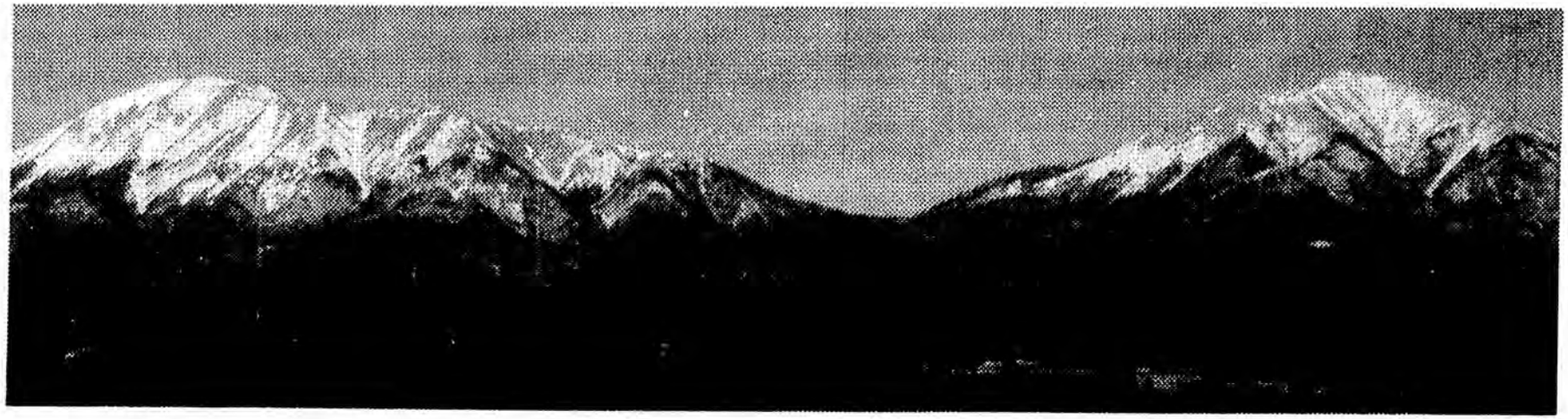
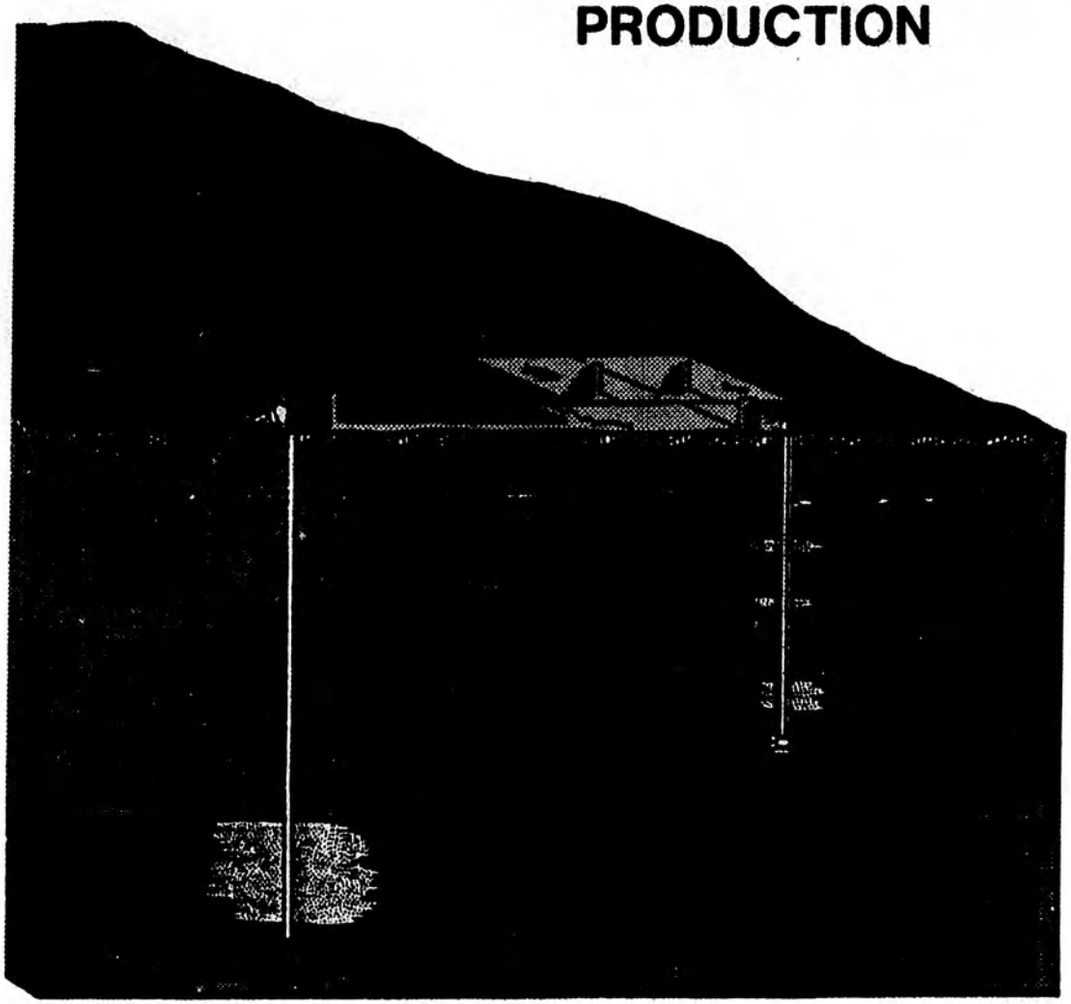


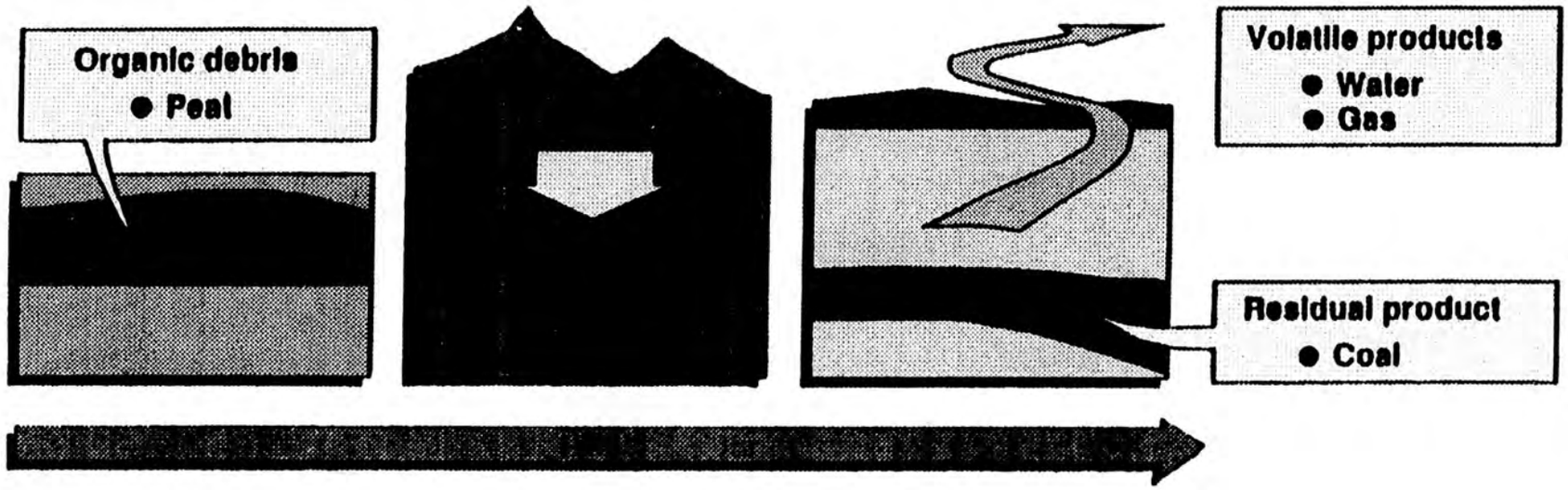
Alaska State Legislature

Joint Committee on Natural Gas Pipelines
November 8, 2001

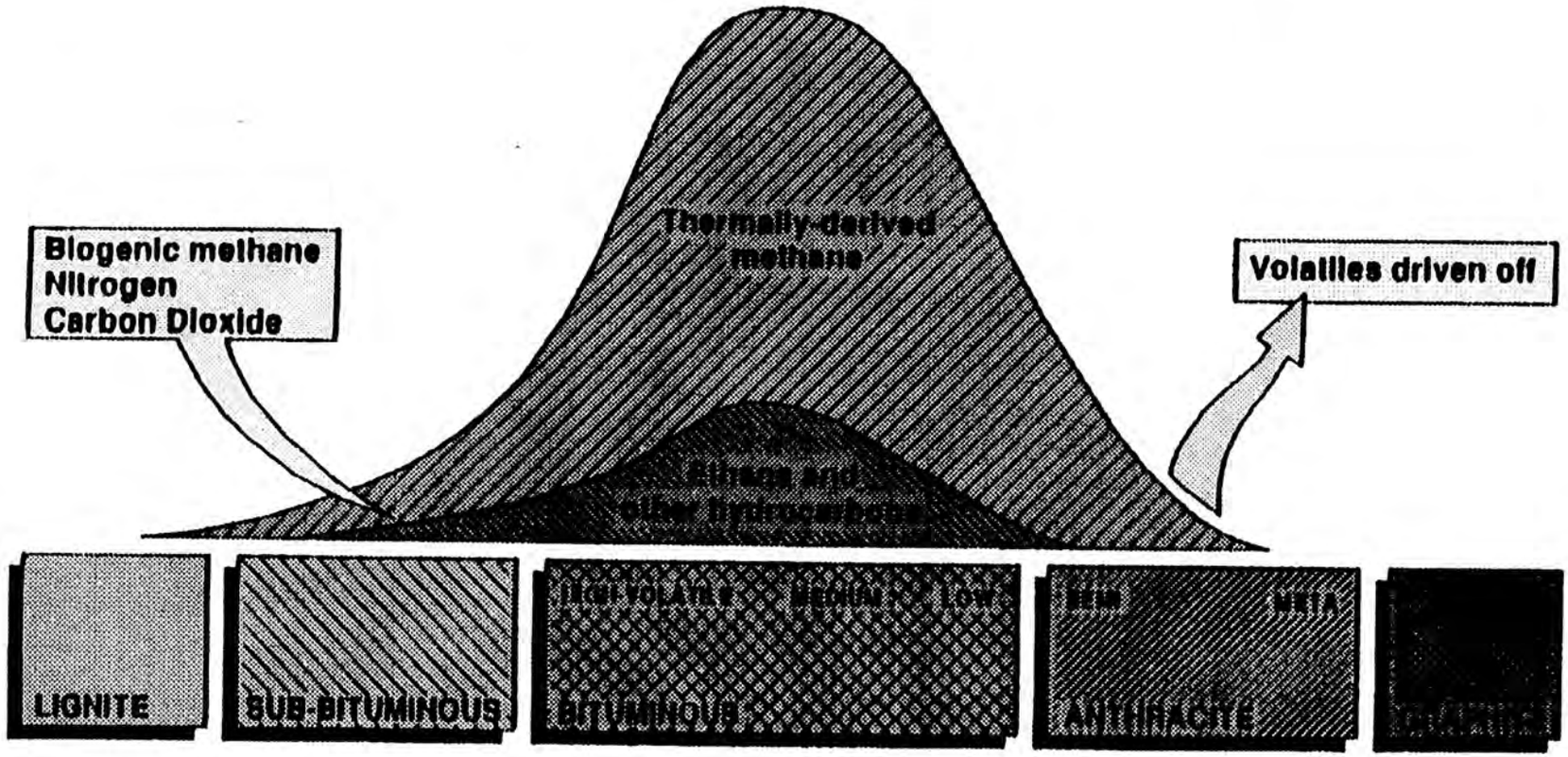
COALBED METHANE PRODUCTION



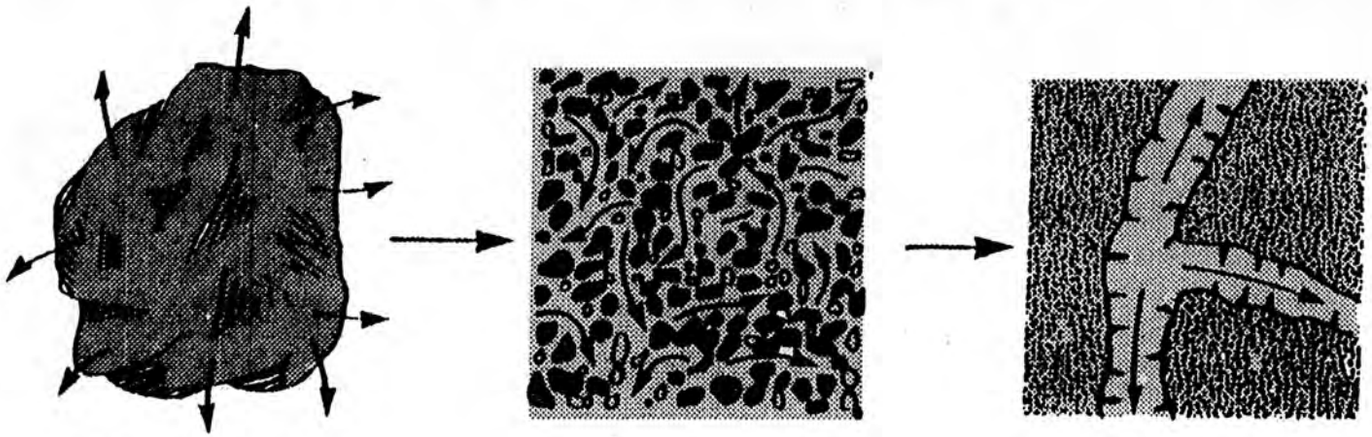
COALIFICATION



GAS GENERATION IN COAL



PROCESSES IN THE TRANSPORT OF COALBED METHANE GAS



Desorption from Internal Coal Surfaces

Diffusion Through the Matrix and Micropores

Fluid Flow in the Natural Fracture Network

Increasing Size →

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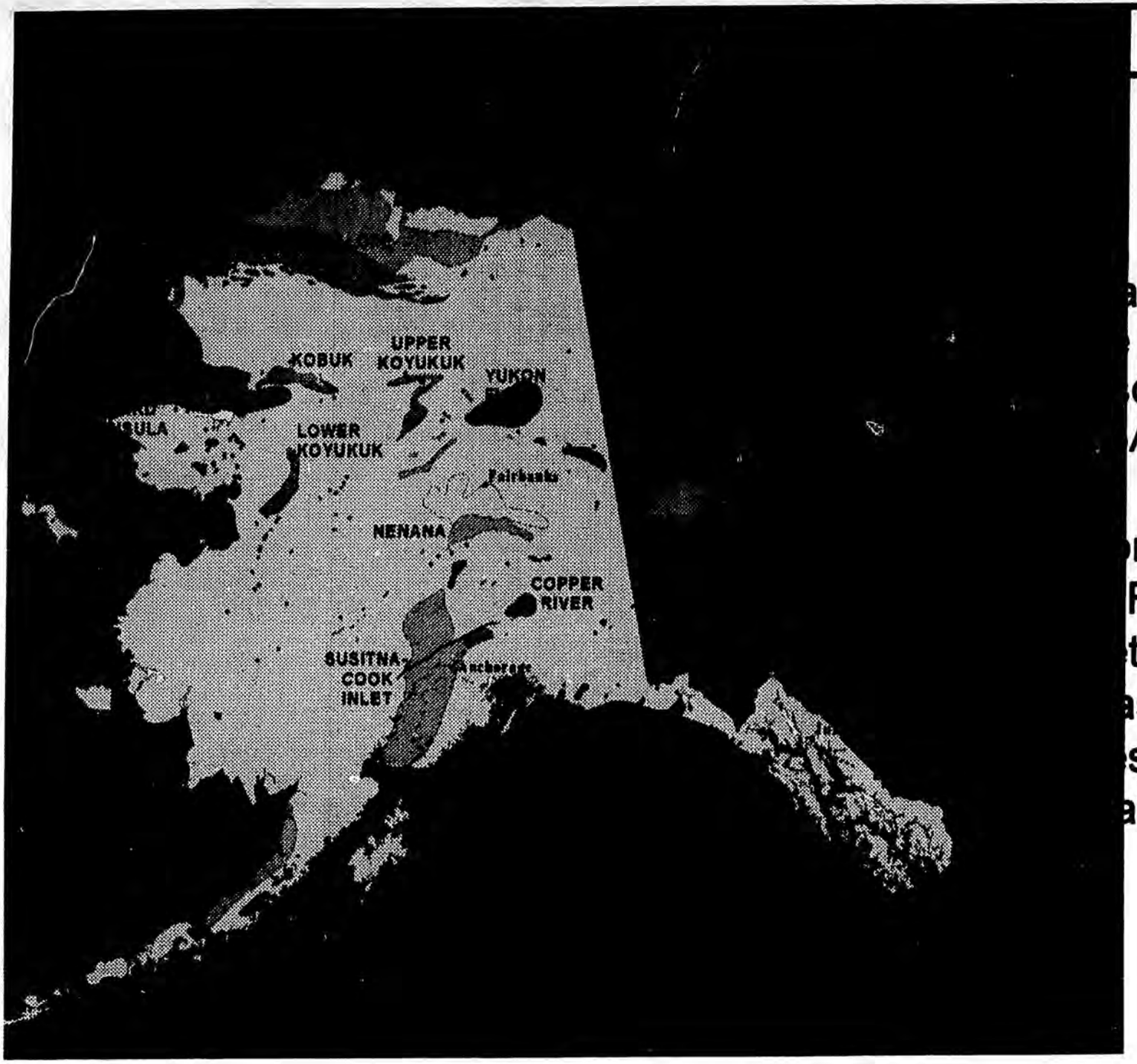

aska has half of
known coal
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A

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F in coal bed
thane resource
associated with
se extensive
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Alaska Cook Inlet Basin

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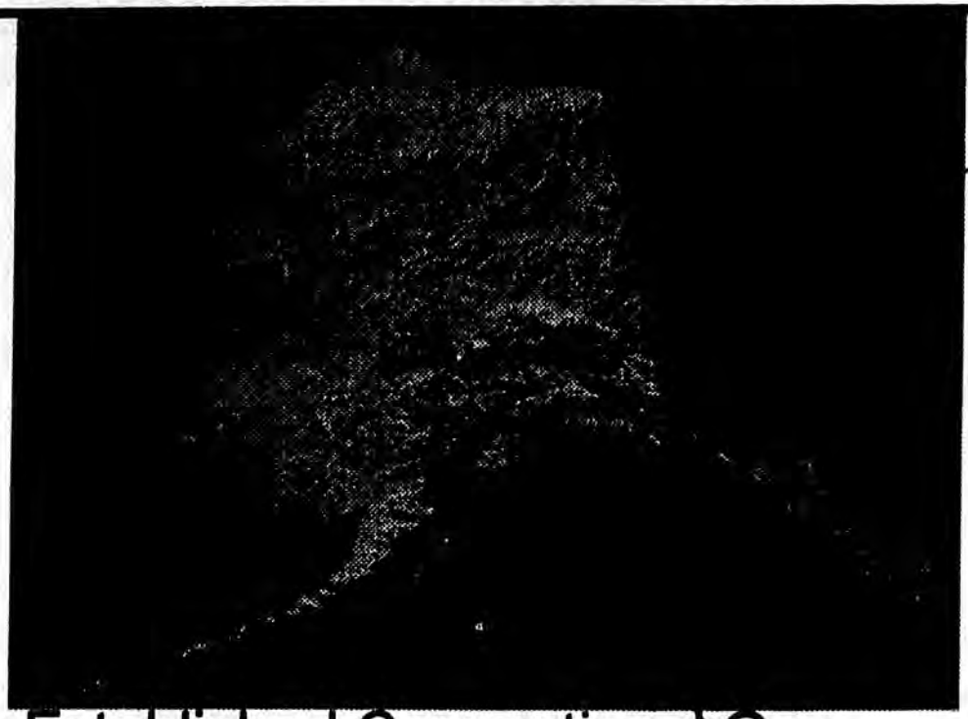

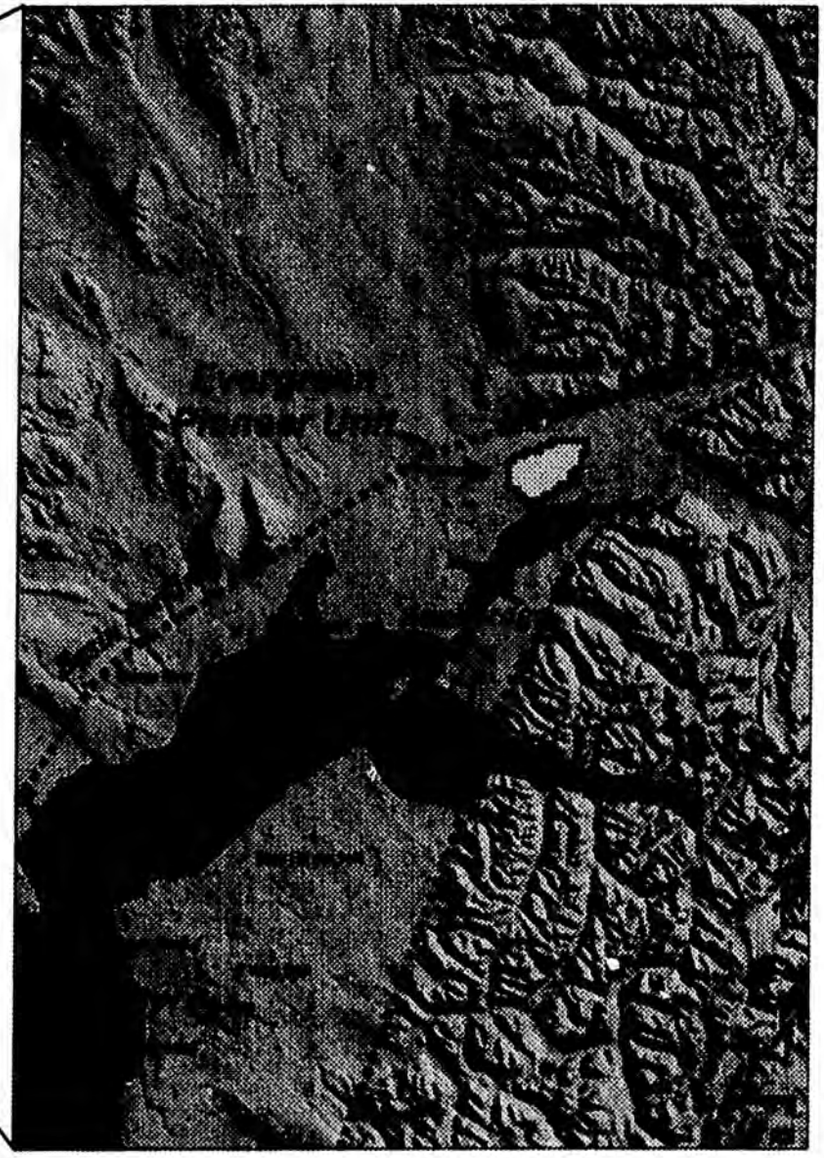

- Established Conventional Gas:
  - Discovered 1957
  - Existing infrastructure
  - Declining gas supply in this region
  - 6.2 Tcf produced to date
- Cook Inlet Basin Resource
  - 1.5 trillion tons coal possible
  - 200 Tcf CBM resource possible
- Evergreen Acquires Pioneer Unit in 2001

Pioneer Unit

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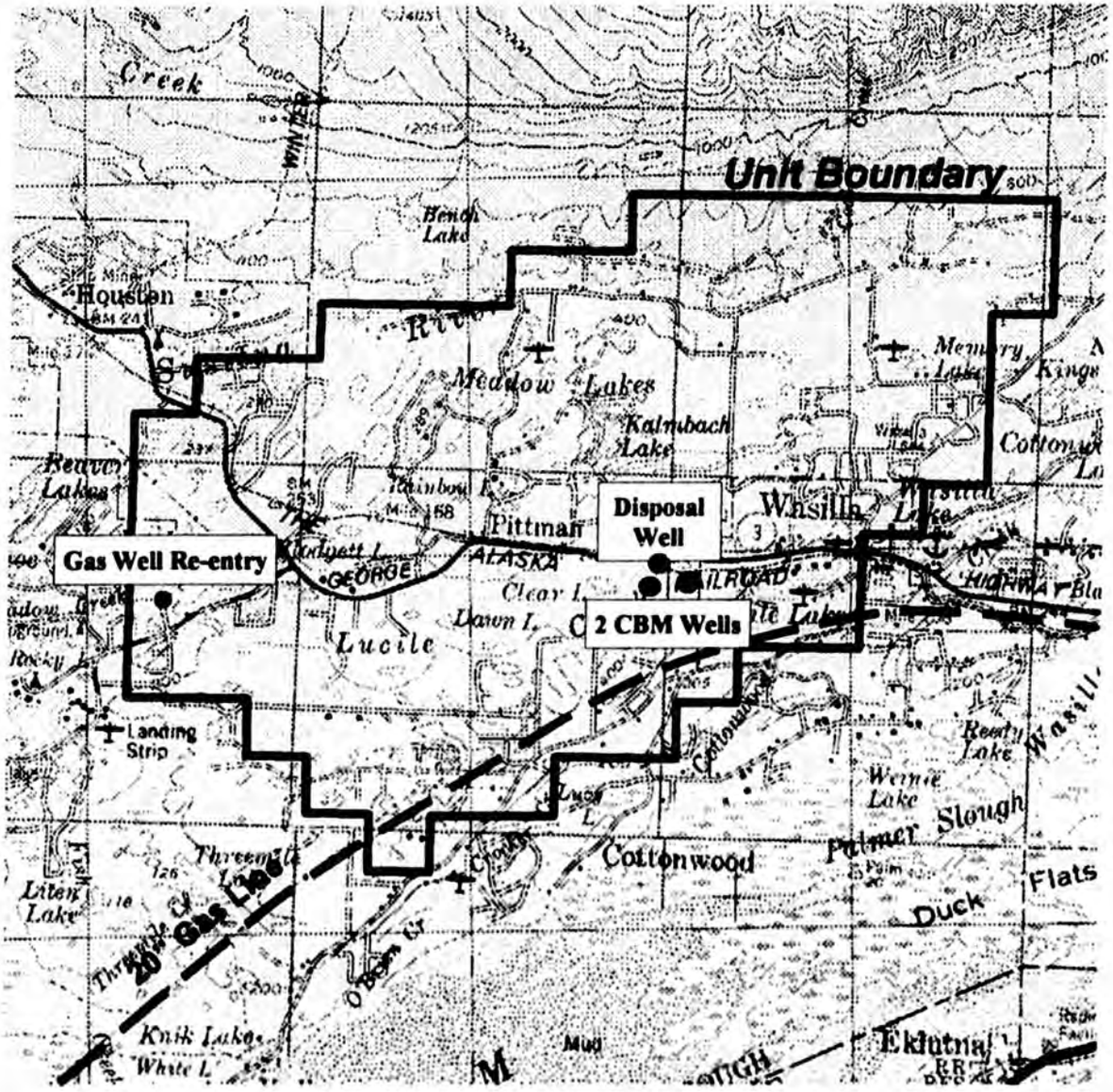
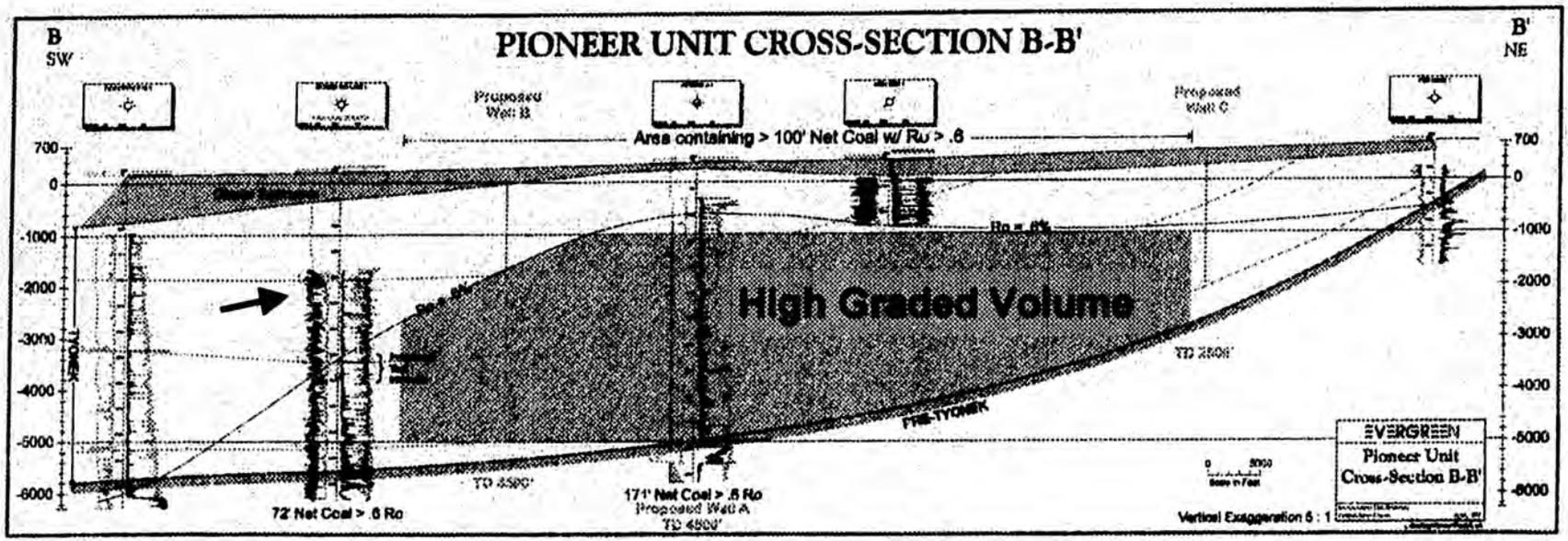
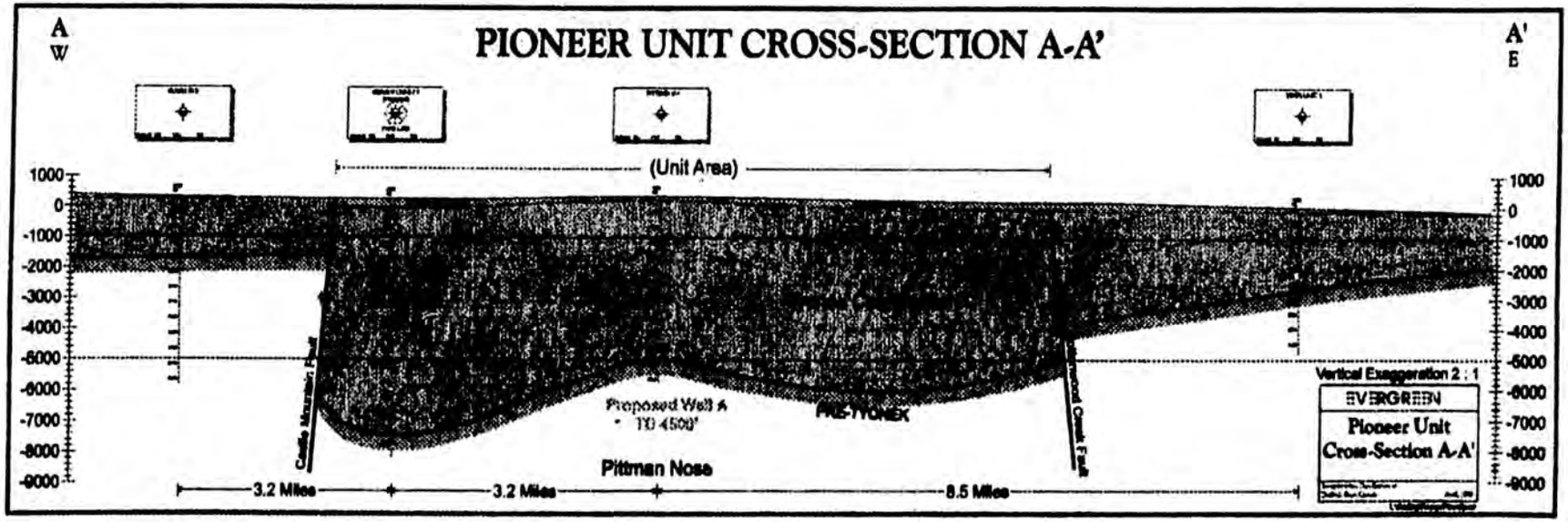


- 48,000 acres
- 100% working interest
- Infrastructure
  - Gas pipeline
- Wells drilled - 2000
  - 2 CBM
  - 1 Water disposal
  - 1 Gas well re-entry
- Future Plans
  - Drill/Complete 6-8 wells in 2002
  - Complete disposal well

Cross Sections

EVERGREEN





Raton Basin

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U.S. Coalbed Methane Resources

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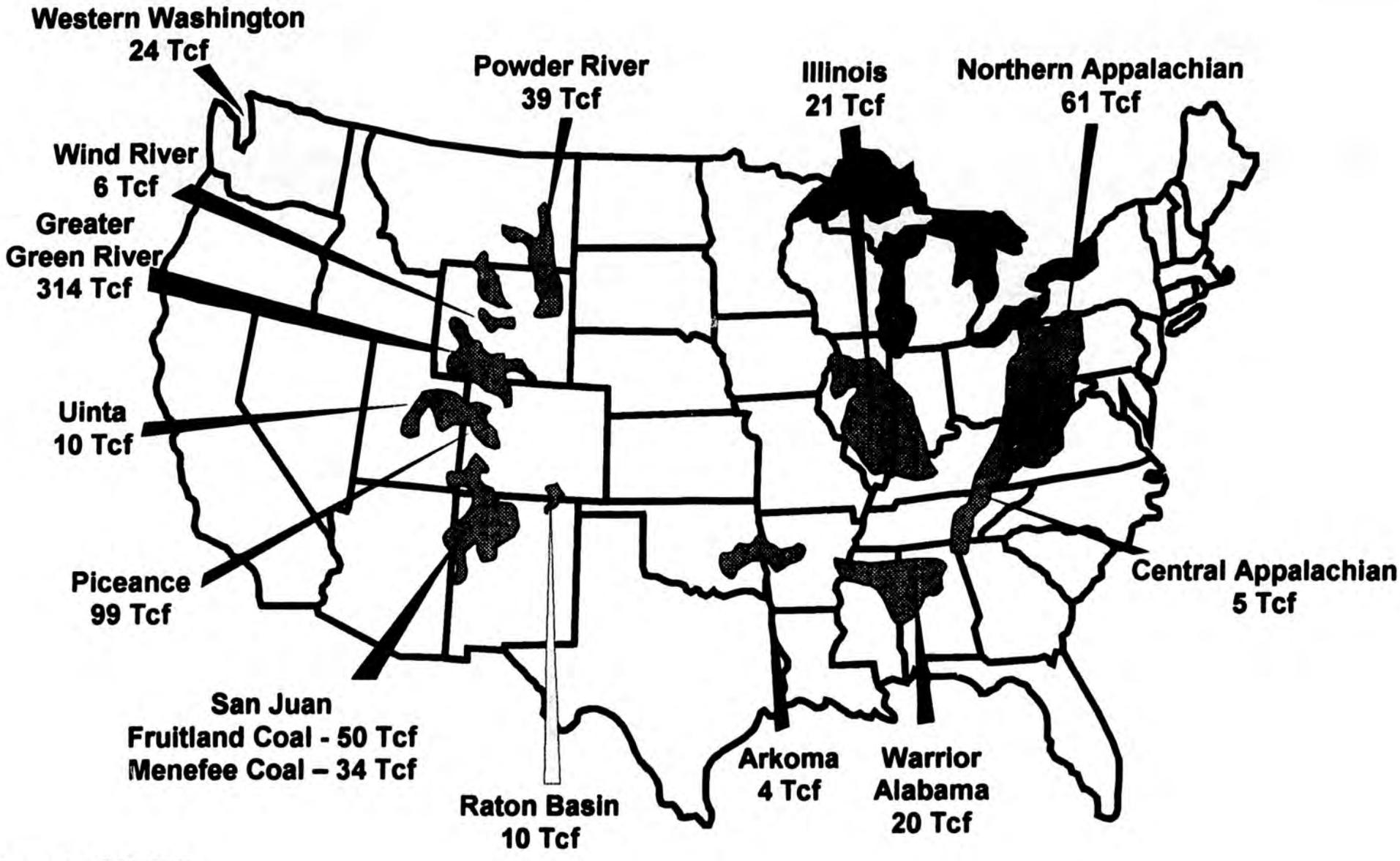

Source: GTI/ICF

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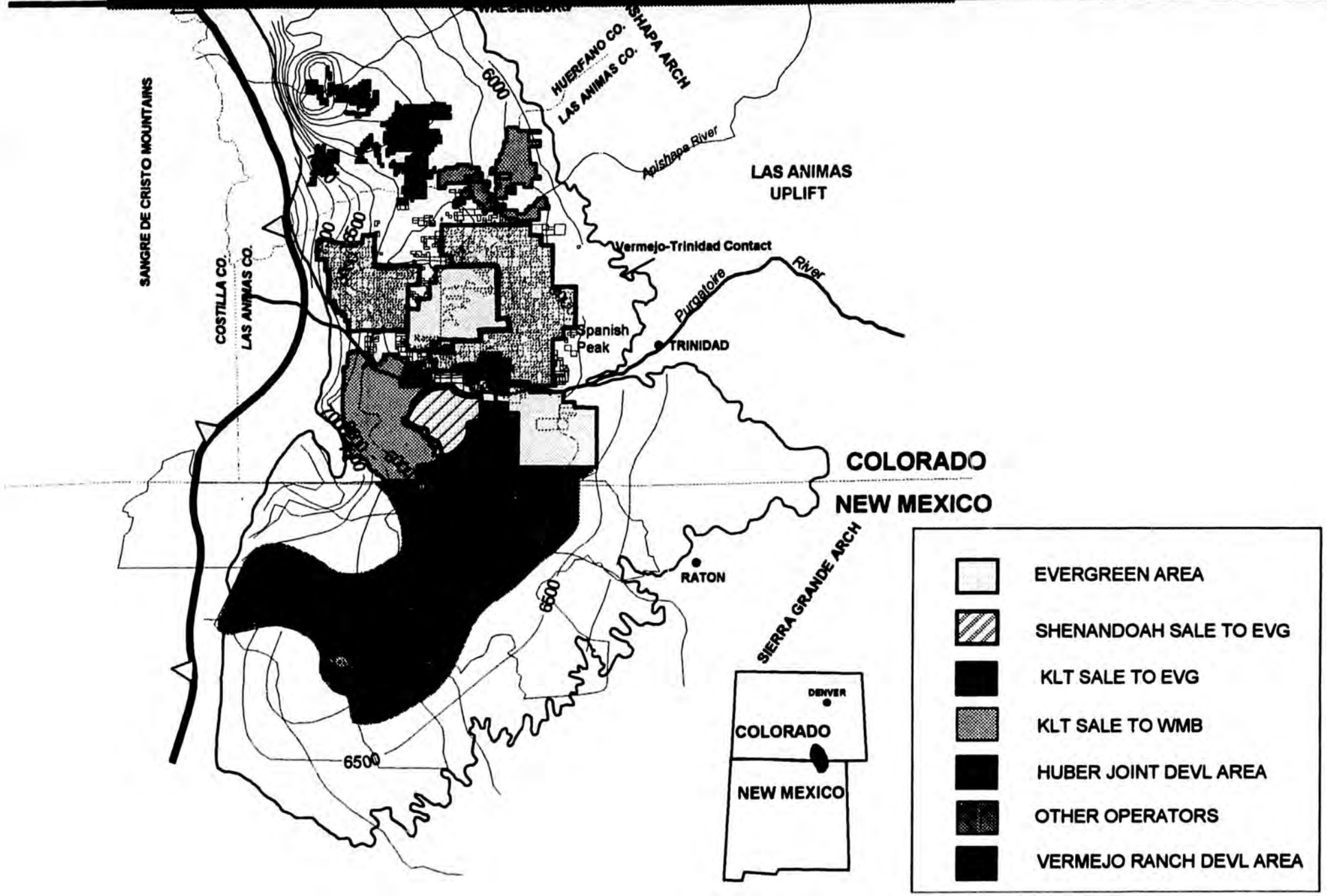

Raton Basin Stratigraphy

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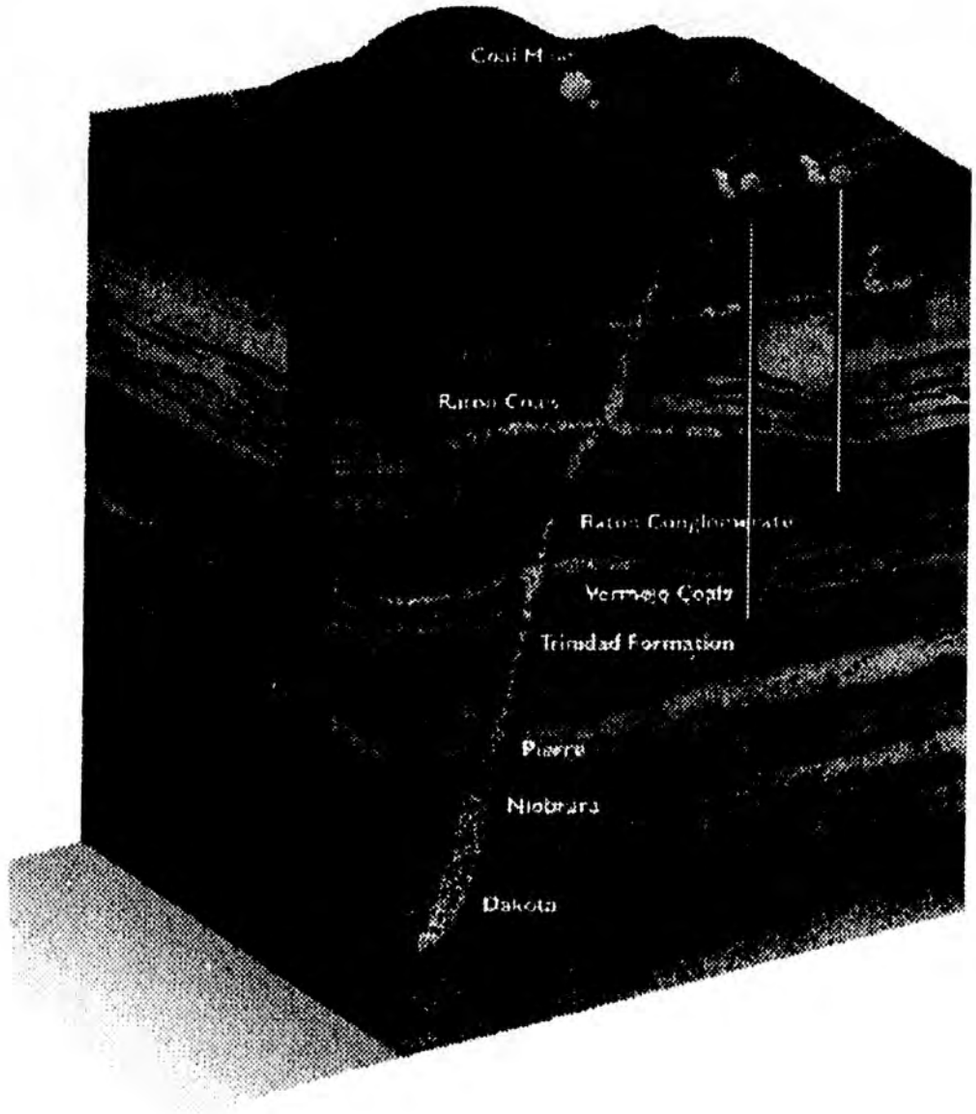
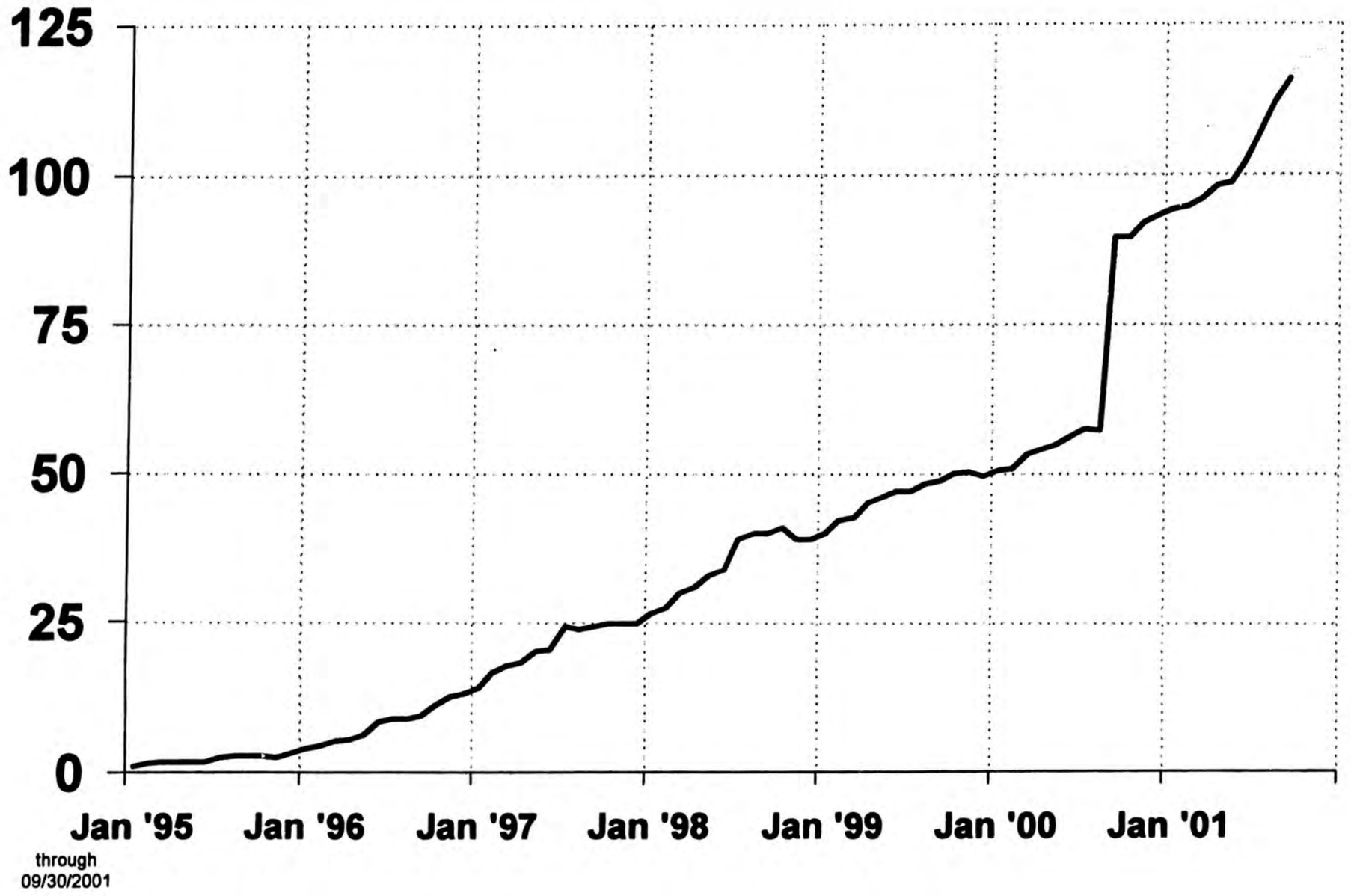


Gross Daily Production

EVERGREEN

(Million Cubic Feet)

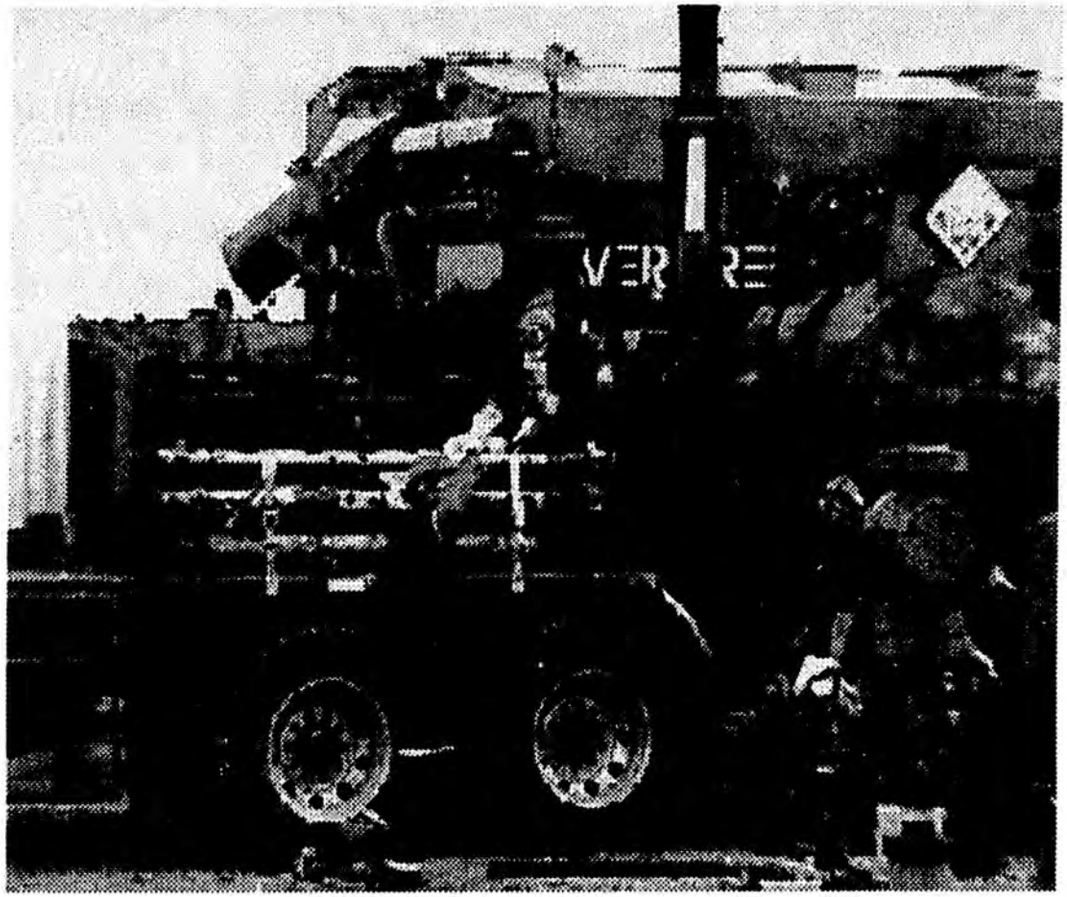


Key Operating Focus

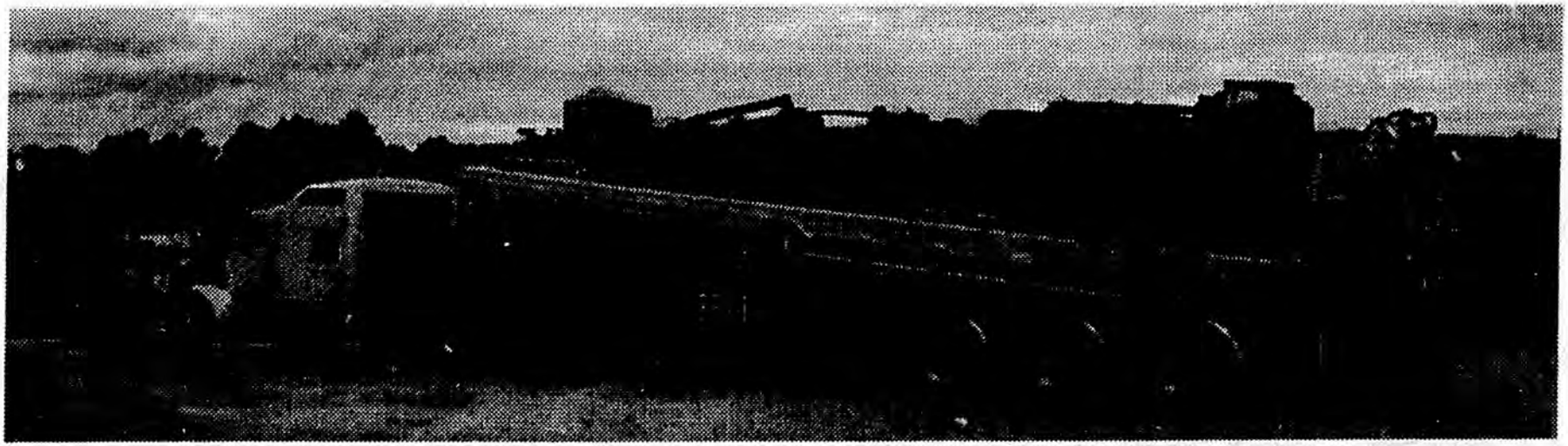
EVERGREEN

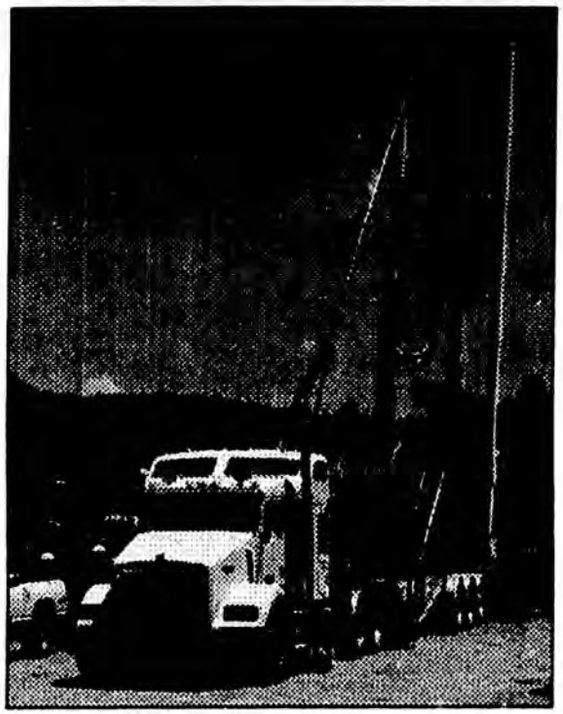
Constant experimentation to improve productivity through new technologies

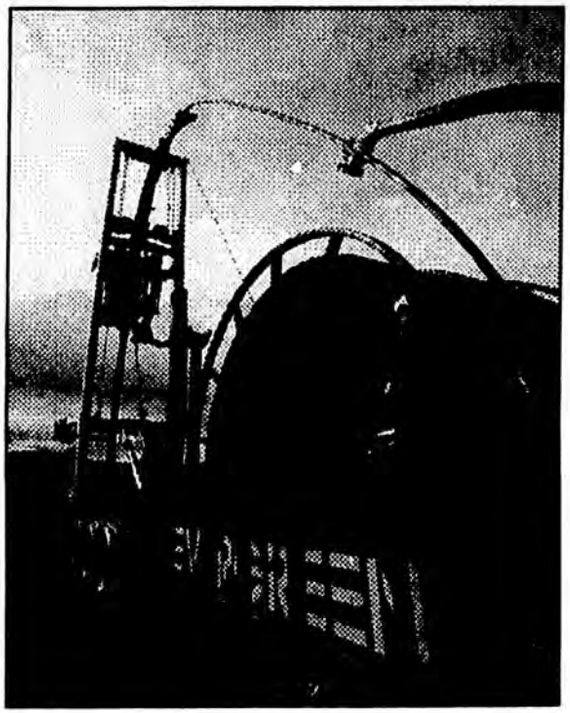
Overall drilling success since 1993: 98%



New Completion Technology



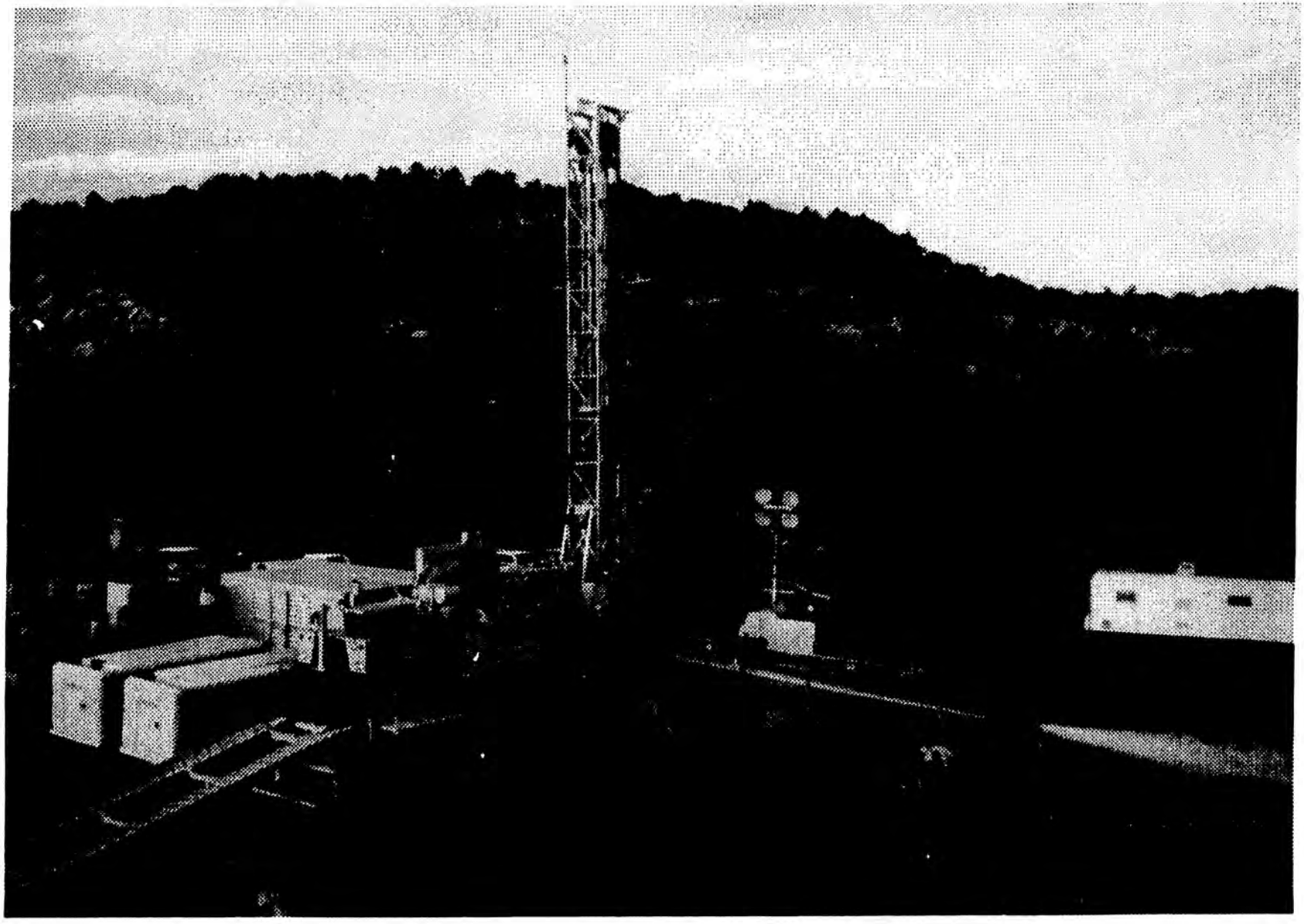






Evergreen Air Drilling Rig

EVERGREEN



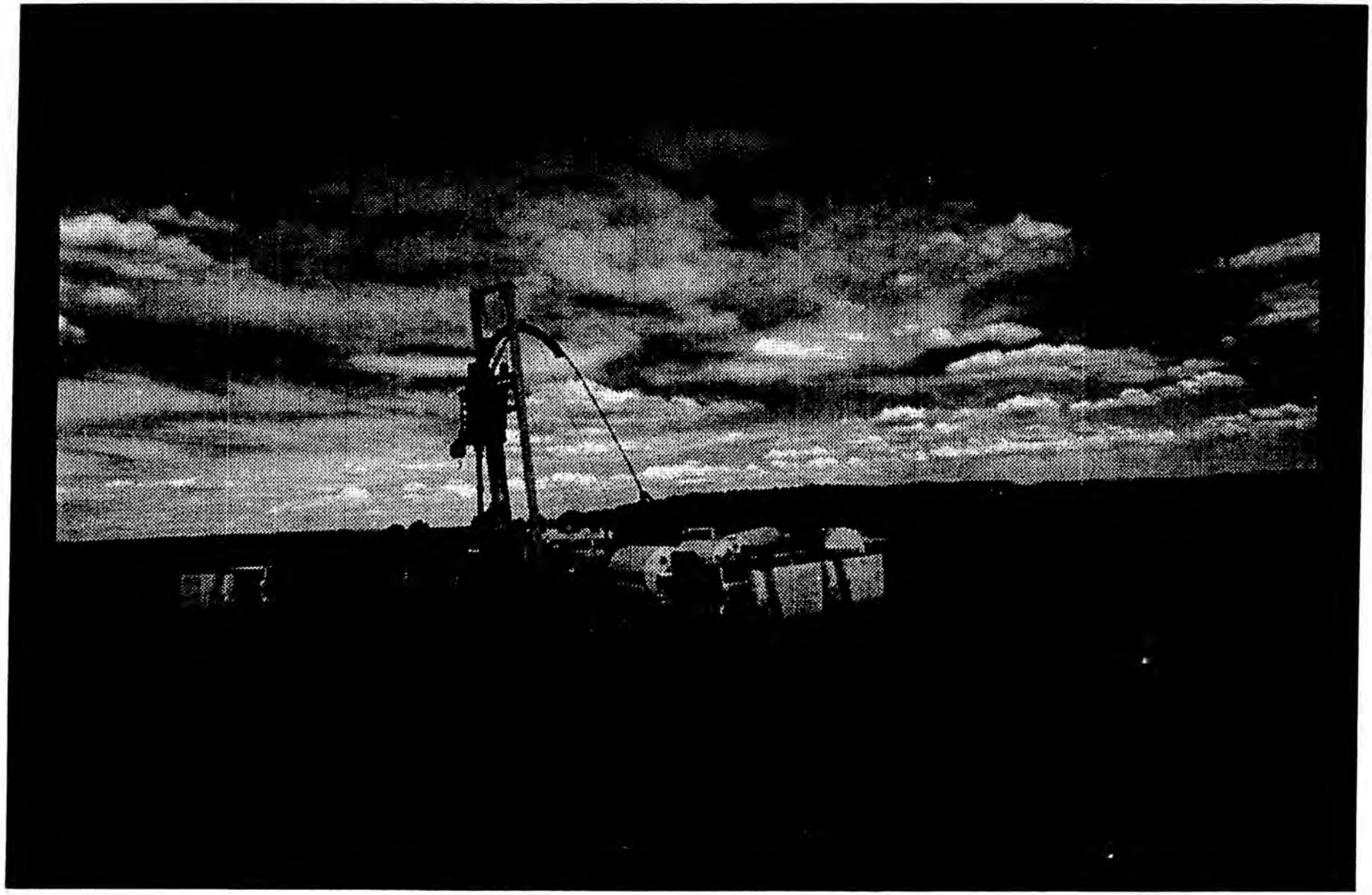
Evergreen Cement Equipment

EVERGREEN



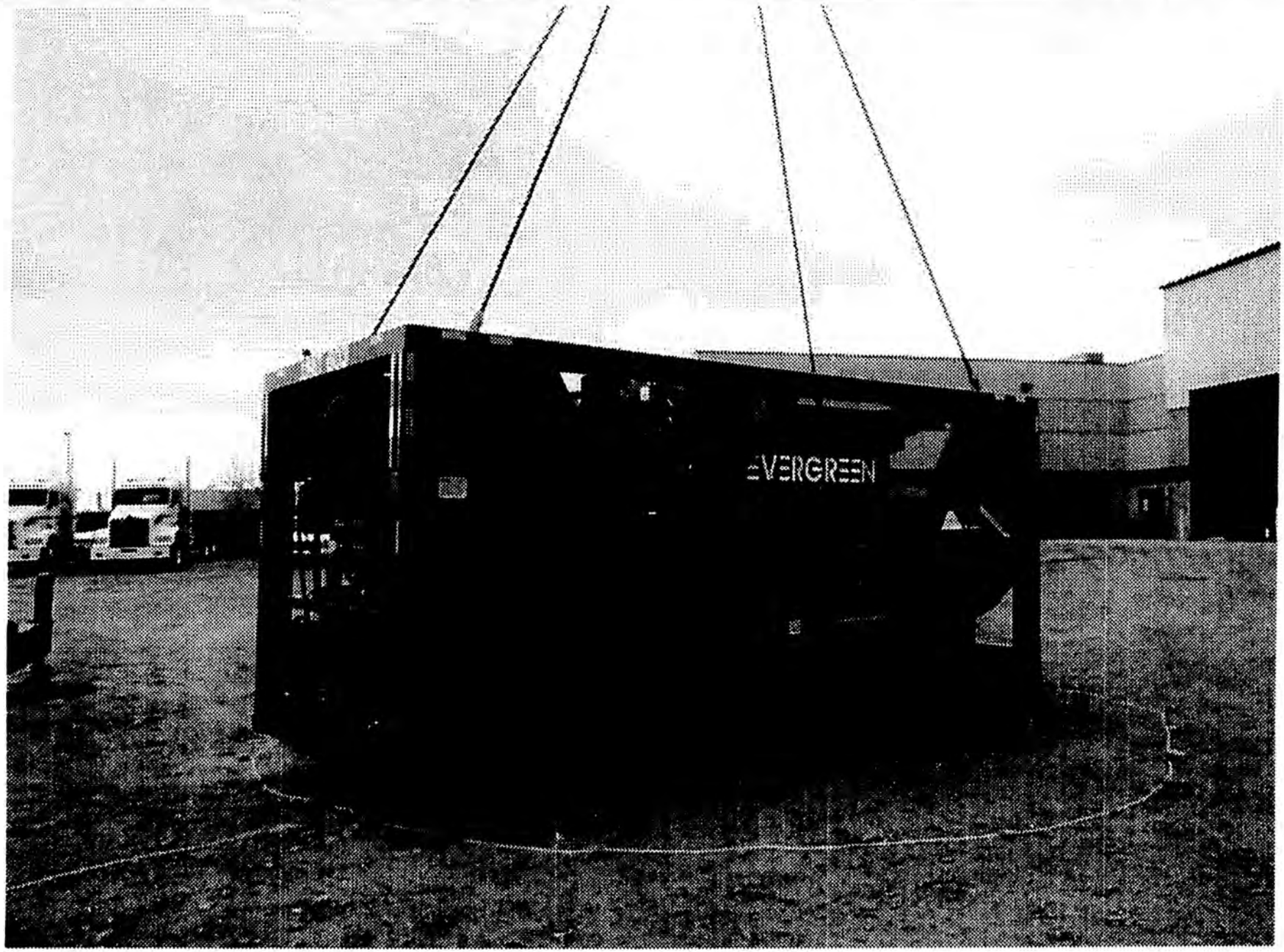
Evergreen Hydraulic Fracture Treatment

EVERGREEN



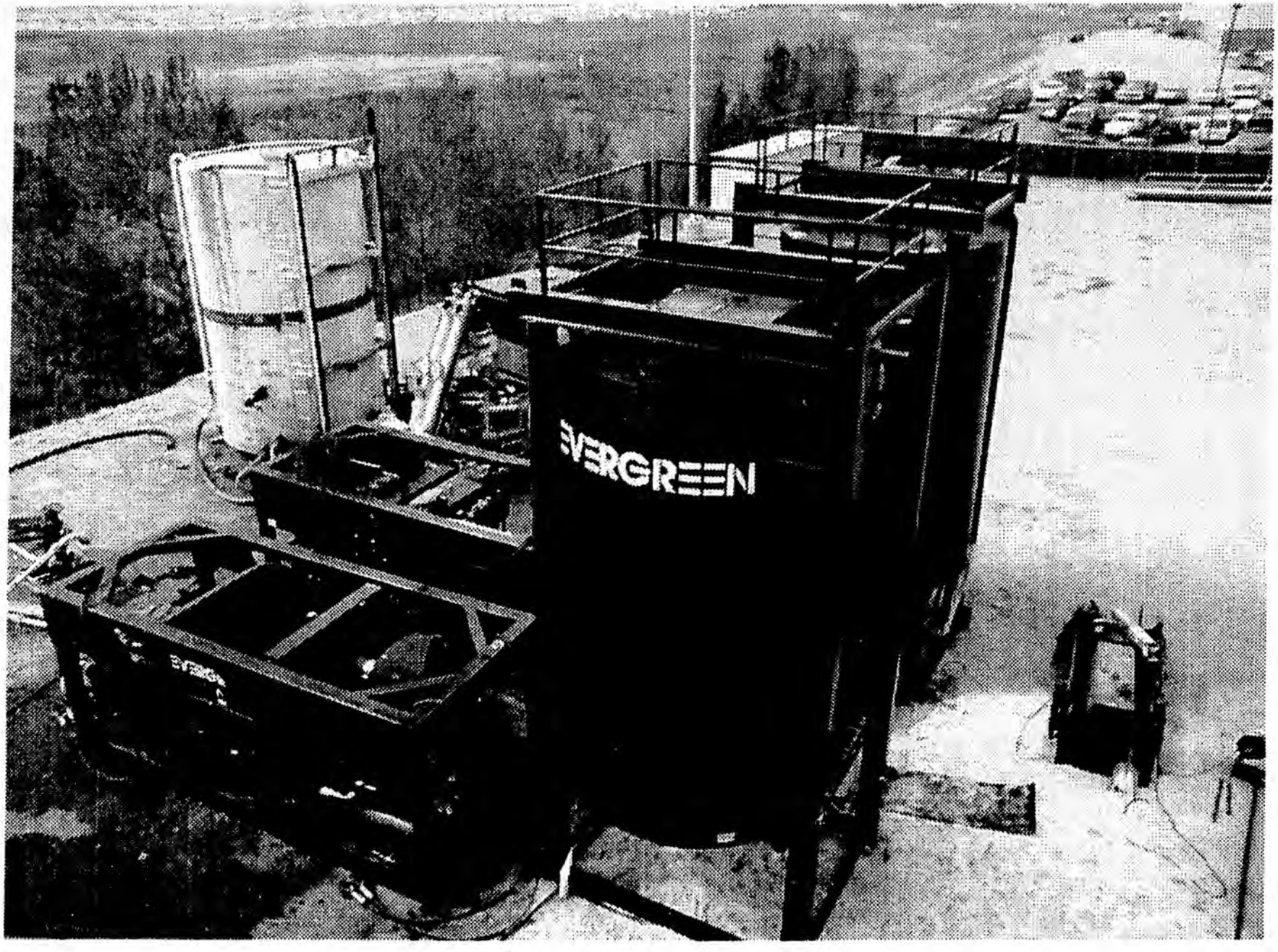
Portable Frac Equipment

EVERGREEN



Portable Frac Equipment

EVERGREEN

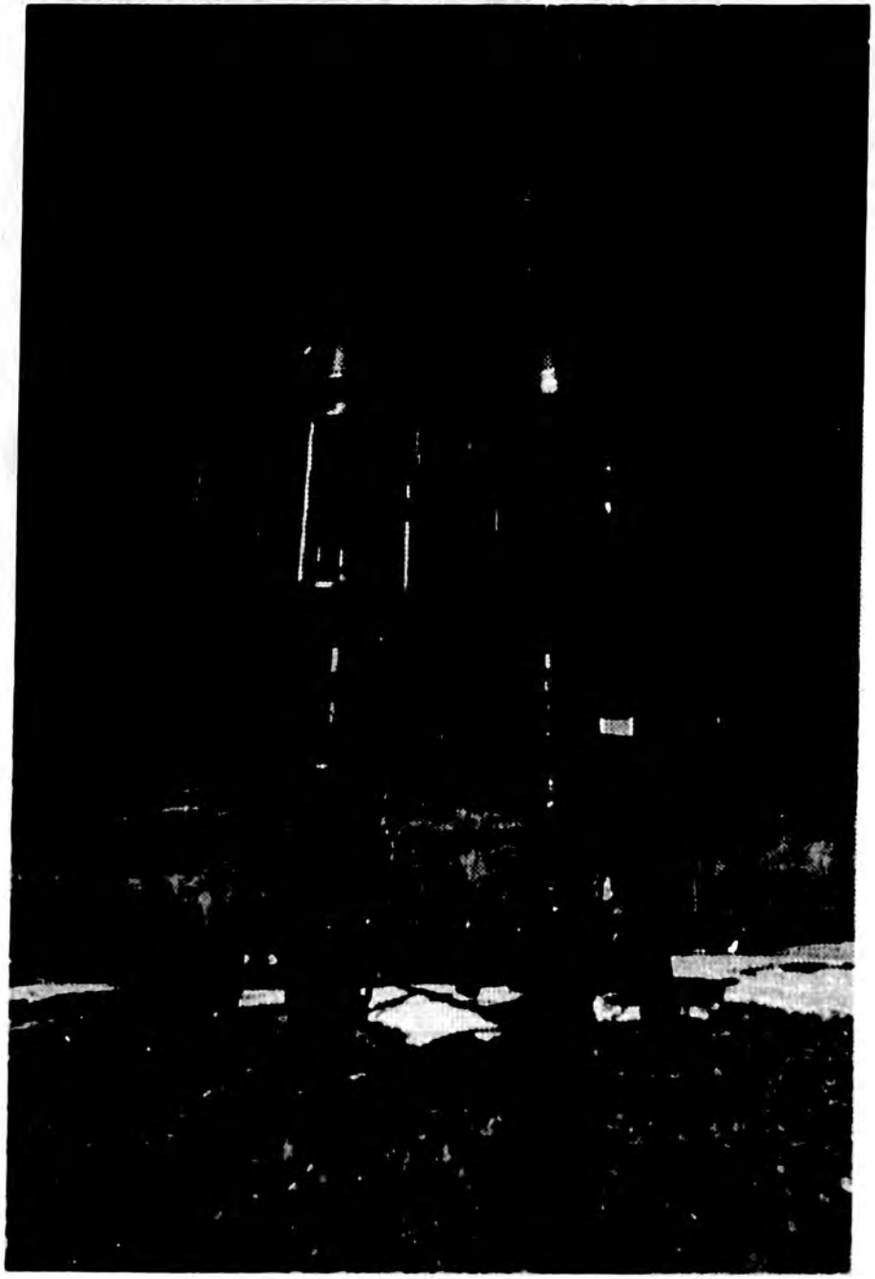


ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2952 SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPLINE, 2001-02

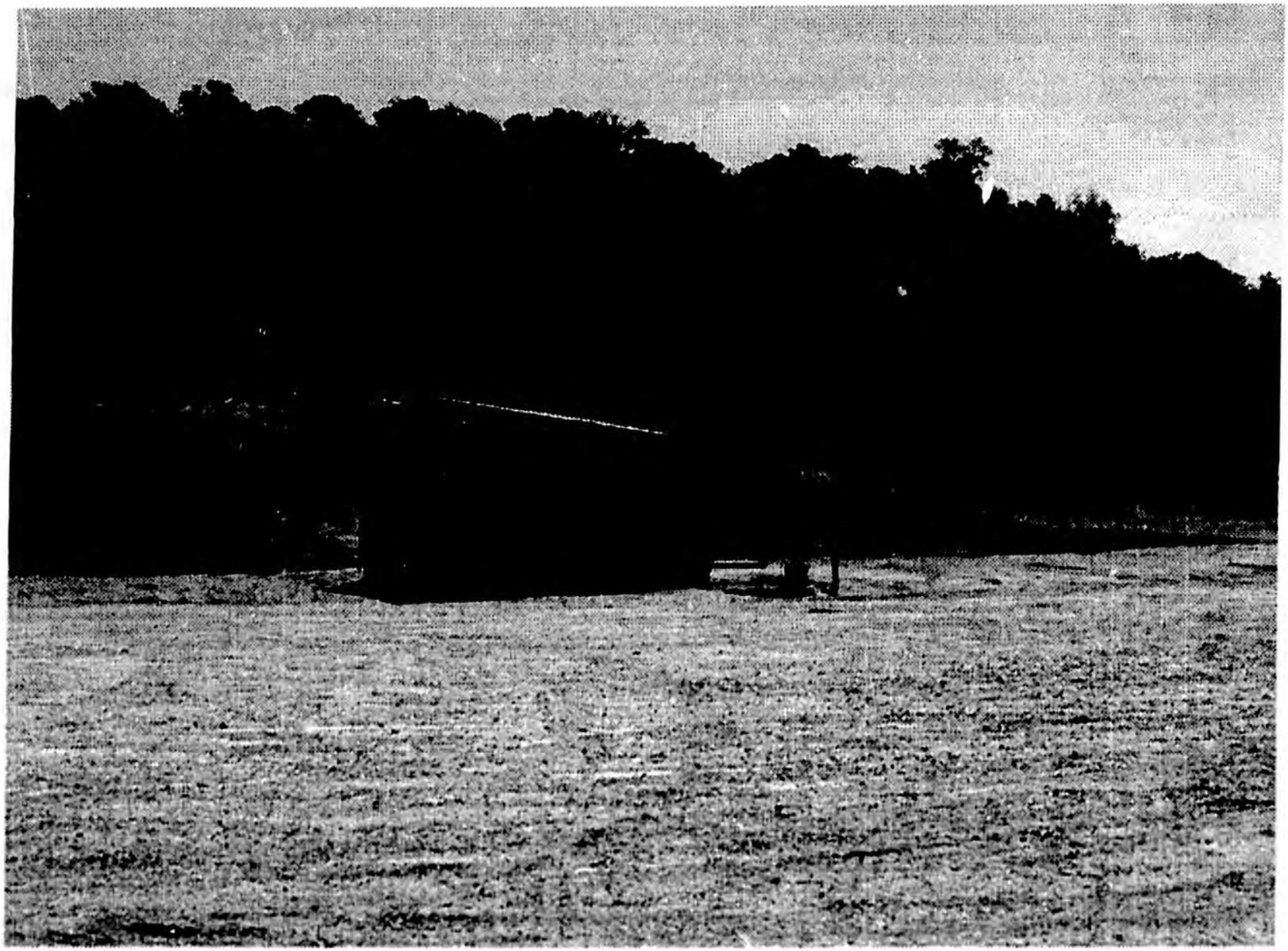
Electric Well Pump

EVERGREEN



Enclosed Gas Engine and Well Pump

EVERGREEN



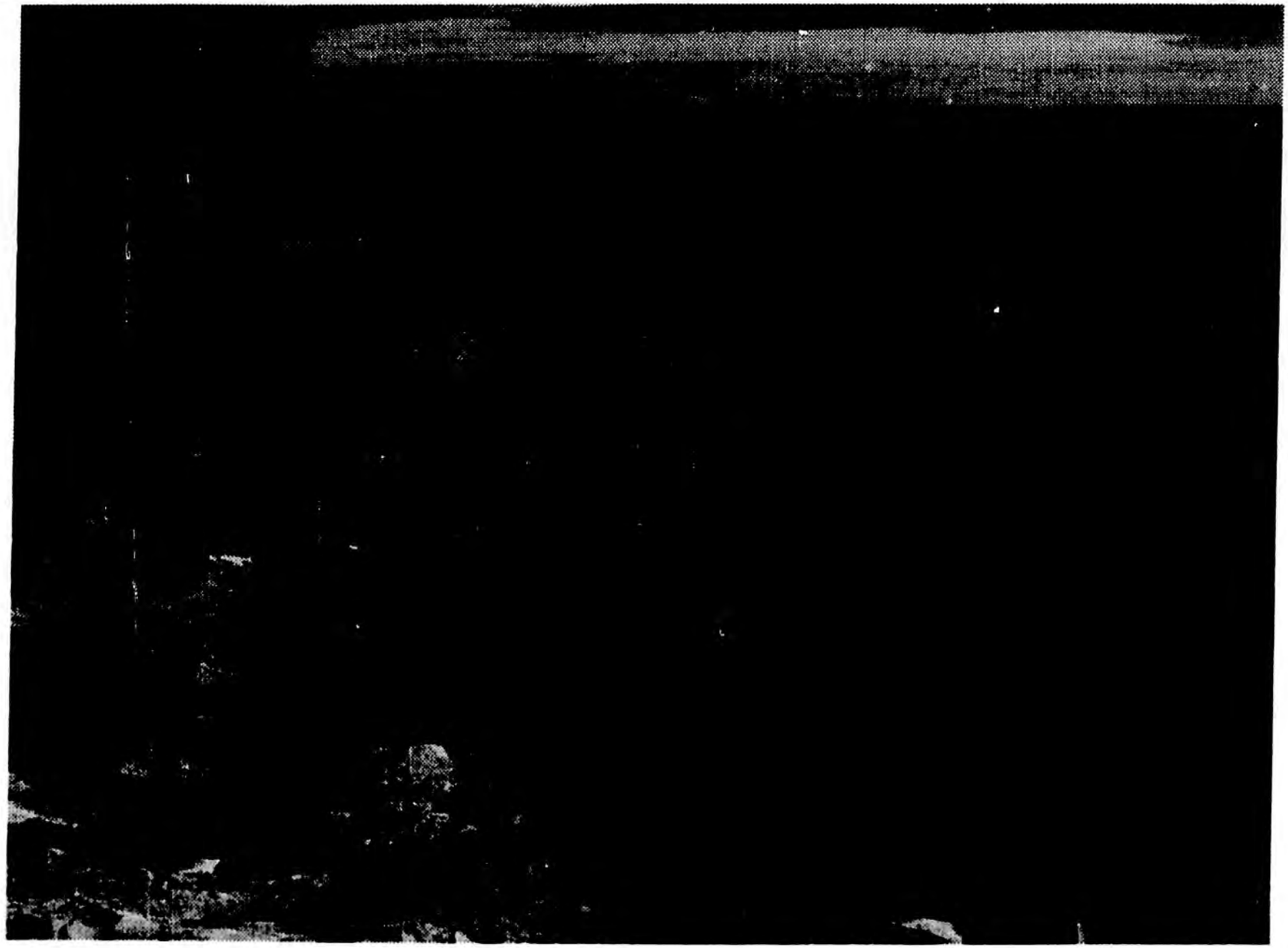
Produced Water-- Evaporation Ponds

EVERGREEN



Produced Water-- Erosion Control

EVERGREEN



Evergreen Pipeline Construction

EVERGREEN



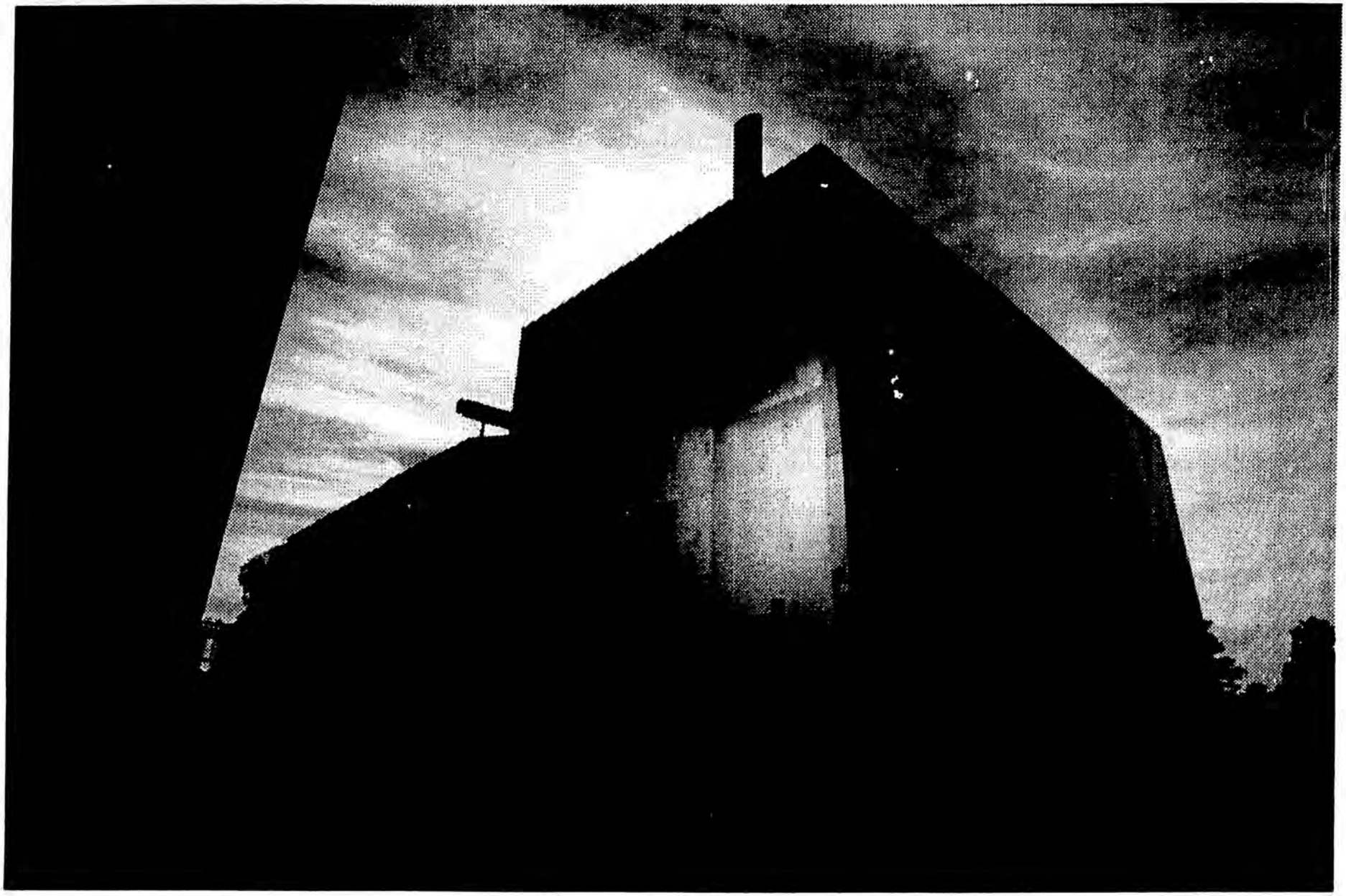
Evergreen Compressor Station

EVERGREEN



Compressor Noise Reducing Structure

EVERGREEN



Committee Request: Address these Topics

EVERGREEN

1. Update on Evergreen's Activities
2. Plans for Gas from North Slope
3. Assessment of Reserves & Undiscovered Resources
4. Evergreen budget for next 5 years
5. Assessment of Cook Inlet Gas Demand
6. Deliverability Constraints in Next 10 Years
7. Recommendations for Legislature

Concluding Remarks

EVERGREEN

- Evergreen's and Alaska's Shared Goal:
  Provide Long-Term Natural Gas Supply for Alaskans

- CBM is a long lived resource and provides us the opportunity to make a long term investment in Alaska

- We support Alaska's gas pipeline efforts to the lower 48

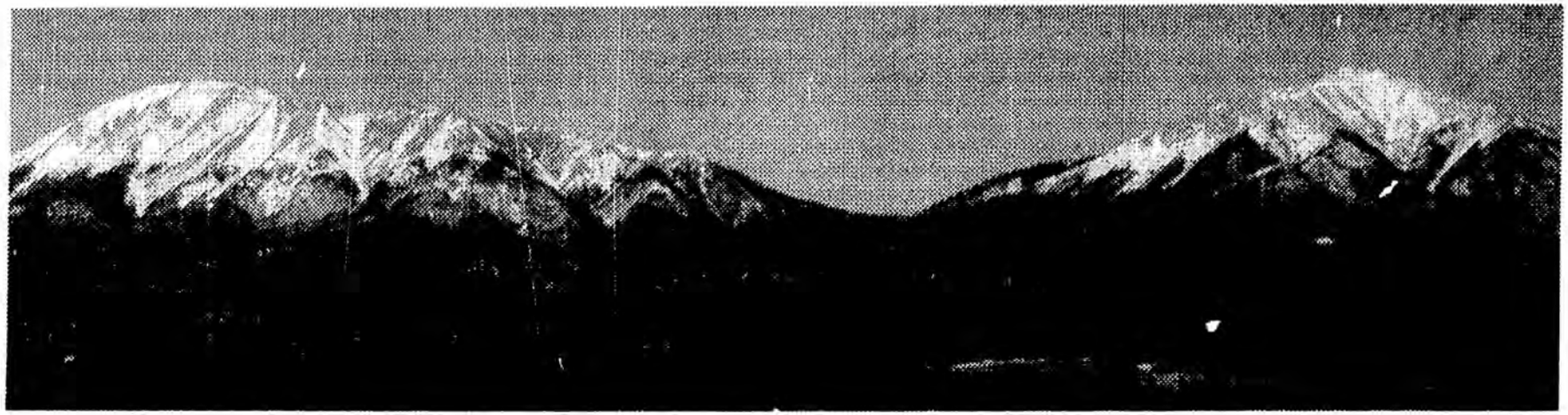
- Above all else, we seek and expect to be contributing citizens of Alaska, providing jobs, environmentally responsible development resulting in a clean energy source. We have done this in the Raton Basin of Colorado, we look forward to replicate that success here.

Forward Looking Statements

EVERGREEN

This presentation contains forward-looking statements within the meaning of federal securities laws, including forward-looking statements regarding Evergreen's natural gas production and realized natural gas price. These statements are subject to various uncertainties. Actual results could differ materially from these forward-looking statements as a result of variety of risks, including, among others, risks that production estimates are inaccurate or gas prices change significantly. Accordingly, there can be no assurance that actual results will be as projected in the forward-looking statements.

EVERGREEN



Recognized Leader in Coal Bed Methane Technology & Development

EVERGREEN RESOURCES, INC.

This presentation contains forward-looking statements within the meaning of federal securities laws, including forward-looking statements regarding Evergreen's oil and gas reserves and the present value of its reserves. These statements are subject to various uncertainties. Actual results could differ materially from those forward-looking statements as a result of variety of risks, including, among others, risks that the reserve estimates are inaccurate or gas prices change such that reserves become uneconomic. Accordingly, there can be no assurance that actual results will be as projected in the forward-looking statement.

COOK INLET NATURAL GAS

The Federal Outer Continental Shelf



John Larson, Geologist

Department of the Interior

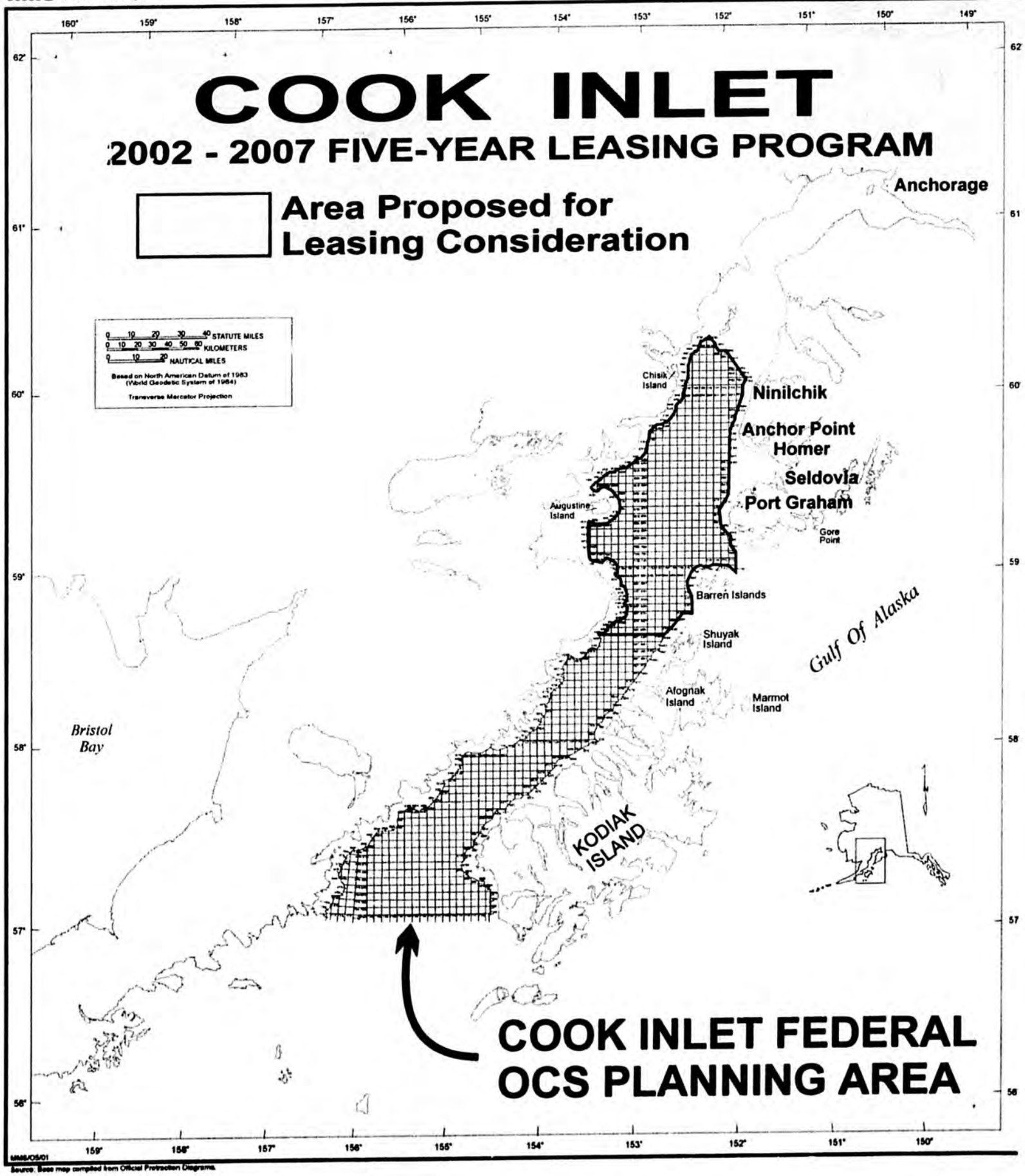
U.S. Minerals Management Service

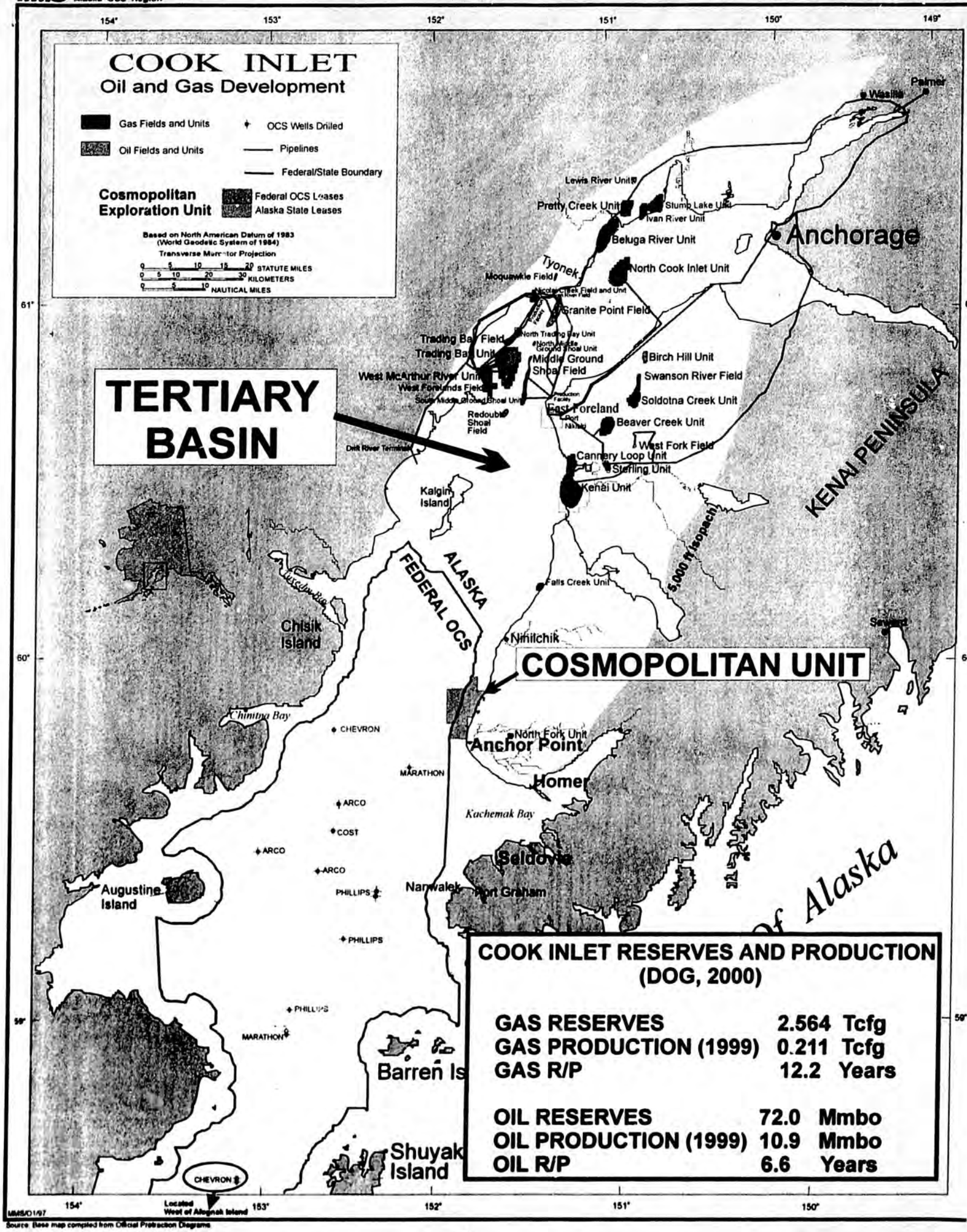
Alaska State Legislature

Joint Committee on Natural Gas Pipelines

November 07, 2001

MM


COOK INLET
2002 - 2007 FIVE-YEAR LEASING PROGRAM
Area Proposed for Leasing Consideration
0 10 20 30 40 STATUTE MILES
0 10 20 30 40 50 60 KILOMETERS
0 10 20 NAUTICAL MILES
Based on North American Datum of 1983 (World Geodetic System of 1984)
Transverse Mercator Projection
Anchorage
Chisik Island
Ninilchik
Anchor Point
Homer
Seldovia
Port Graham
Augustine Island
Gore Point
Barren Islands
Shuyak Island
Gulf Of Alaska
Afognak Island
Marmot Island
Bristol Bay
KODIAK ISLAND
COOK INLET FEDERAL OCS PLANNING AREA
160° 159° 158° 157° 156° 155° 154° 153° 152° 151° 150° 149°
62° 61° 60° 59° 58° 57° 56°
MMS/OS/01
Source: Base map compiled from Official Protraction Diagrams.



COOK INLET RESERVES AND PRODUCTION (DOG, 2000)

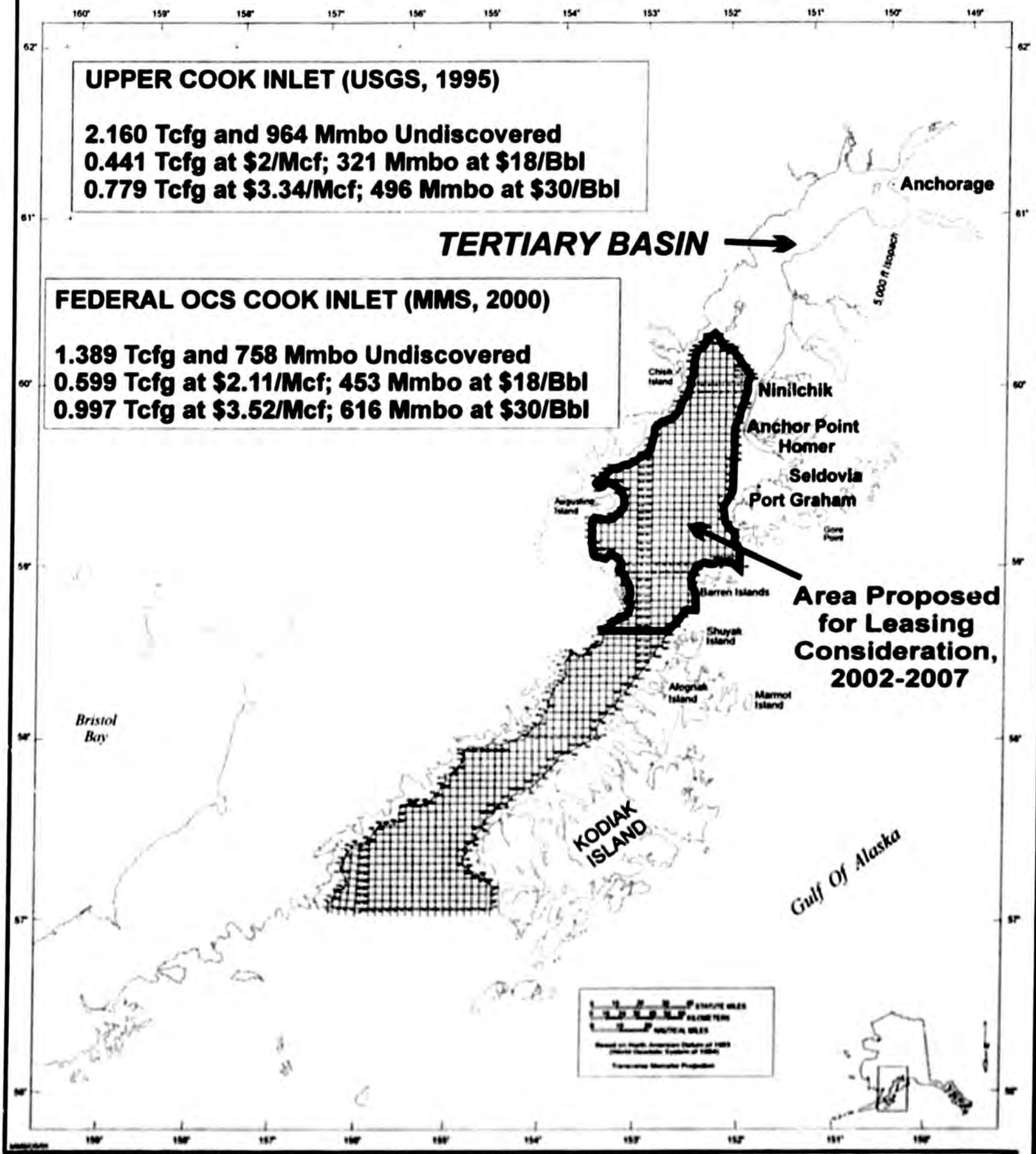
GAS RESERVES	2.564	Tcfg
GAS PRODUCTION (1999)	0.211	Tcfg
GAS R/P	12.2	Years
OIL RESERVES	72.0	Mmbo
OIL PRODUCTION (1999)	10.9	Mmbo
OIL R/P	6.6	Years

MMS/01/97

Source: these map compiled from Official Protraction Diagrams

COOK INLET

UNDISCOVERED OIL AND GAS RESOURCES



In Conclusion

- Cook Inlet basin has significant untapped natural gas resources

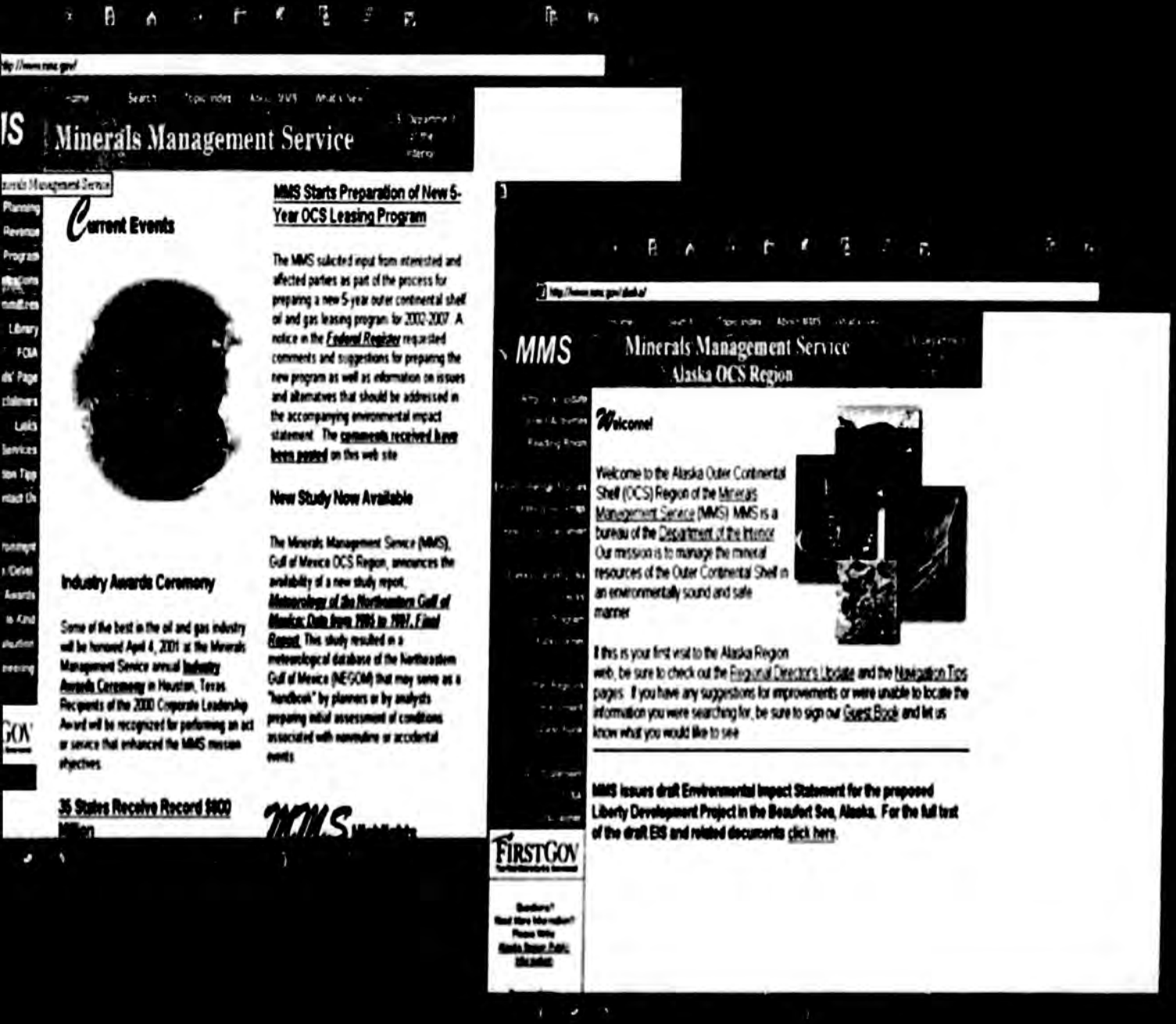
- The MMS is proposing two oil and gas lease sales in years 2004 & 2006 for the most promising portion of the Federal OCS part of Cook Inlet basin



For more information

http://www.mms.gov/

http://www.mms.gov/alaska/



ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

Official Business

Senator John Torgerson, Chair
Senator Rick Halford
Senator Pete Kelly
Senator Johnny Ellis

Representative Joe Green, Vice-Chair
Representative Brian Porter
Representative Scott Ogan
Representative John Davies

MEMORANDUM

To: Members of the Joint Committee on Natural Gas Pipelines

From: Senator John Torgerson

Re: Committee correspondence for the hearing on November 7 & 8

Date: November 7, 2001

Attached, please find a copy of written testimony from invitees who have chosen not to testify in person.

- Chugach Electric Association
- Forest Oil Corporation
- Yukon Pacific Corporation
- Alaska Gasline Port Authority
- Gas-Pro Alaska

Session: January – May
State Capitol, #427
Juneau, AK 99801
Phone: 907-465-2828
Fax: 907-465-4779

Interim: May – December
35477 Kenai Spur Hwy., Suite 101A
Soldotna, AK 99669
Phone: 907-260-3041
Fax: 907-260-3044

CHUGACH ELECTRIC
ASSOCIATION, INC.

GENERAL COUNSELS' OFFICE
PHONE: (907) 762-4790
FAX: (907) 762-4688

November 1, 2001

VIA TELEFAX

Senator John Torgerson
Alaska State Legislature
35477 Kenai Spur Hwy., Ste. 101A
Soldotna, AK 99669

Dear Senator Torgerson:

Thank you for the opportunity to participate in the public hearing set for November 7th and 8th in Kenai on Southcentral natural gas supply issues. While Chugach does not intend to testify, I have enclosed a copy of a document entitled "2001 Ten-Year Natural Gas Fuel Requirements Projection" which summarizes Chugach's anticipated natural gas needs. This document responds to the first topic referenced in your letter of October 22, 2001.

In response to your question about possible expansion plans in the event a natural gas supply is made available from the North Slope, Chugach's needs for fuel are based on electric power loads in Southcentral. To the extent that growth in loads results from the availability of North Slope natural gas in Southcentral Alaska, Chugach would be prepared to expand electric power production and transmission as needed to meet those needs.

As this is a topic in which Chugach is keenly interested, I will be reviewing the testimony submitted by other participants in this hearing. I would also appreciate being placed on any list you maintain of people to keep informed on this and related topics. You can reach me by email at don_edwards@chugachelectric.com or by phone at (907) 762-4637.

Sincerely,

Donald W. Edwards
General Counsel

Enclosure

Chugach Electric Association, Inc.
Asset Management

2001 Ten-Year Natural Gas Fuel Requirements Projections

Attachment 1

Based on 2001 Power Requirements Study, Mid Load Growth Case
Amounts in Thousand MCF's

		FIRM REQUIREMENTS							POTENTIAL ECONOMY SALES		MARATHON TOTALS			TOTAL REQUIREMENTS
Plant →		Beluga Plant		Beaver Lake	Nikiski	IGT	UHPS Fuel Cell Plant	AIA Cages	Beluga Plant	Beaver Lake				
Fuel →	New Contract Source (See Note 1)	Beluga Producer Fuel (1)	Marathon	Marathon	Marathon	Marathon ENSTAR Transport	Marathon ENSTAR Transport	Marathon ENSTAR Transport	Marathon	Marathon	Firm	Economy Sales	Total Marathon	
Year	(000 MCF) →										→			(000 MCF)
2001	0	11,378	7,585	441	3,123	59	80	0	2,244	369	11,288	2,613	13,901	25,280
2002	0	11,825	7,965	268	3,626	62	81	0	2,233	367	12,000	2,600	14,600	26,426
2003	0	11,715	7,891	475	3,626	75	81	306	2,233	367	12,455	2,600	15,055	26,769
2004	0	12,056	8,119	601	3,636	78	82	335	2,233	367	12,850	2,600	15,450	27,586
2005	0	12,419	8,360	241	3,626	50	81	334	2,233	367	12,691	2,600	15,291	27,710
2006	0	12,585	8,472	855	3,626	109	82	334	2,256	370	13,477	2,626	16,103	28,687
2007	0	12,754	8,584	905	3,626	130	82	334	2,278	374	13,660	2,652	16,312	29,066
2008	0	12,855	8,651	328	3,636	52	82	335	2,301	378	13,084	2,679	15,762	28,617
2009	4,816	13,536	4,208	515	3,626	63	39	161	2,324	381	8,612	2,706	11,318	29,670
2010	17,045	13,241	0	0	0	0	0	0	0	0	0	0	0	30,286

Notes:

(1) Forecast assumes Soldotna #1 unit is relocated and operational as Nikiski Unit #1 at UNOCAL's Nikiski Refinery by February 15, 2001. Assumed Nikiski site fuel sources: 100% Marathon contract gas.

(2) It is anticipated that Marathon contract vo... ill be depleted by mid-year 2009. The forecast assumes that new contract fuel sources (presently unidentified) will be in place starting in 2009.

FOREST OIL CORPORATION

310 K. Street • Suite 700
Anchorage, Alaska 99501
(907) 258-8600 • (907) 258-8601 (Fax)

October 25, 2001

Honorable John Torgerson/Joe Green
Joint Committee on Natural Gas Pipelines
State Capitol, #427
Juneau, AK 99801

Fax: 907-260-3044

Dear Honorable John Torgerson/ Joe Green,

Thank you for the invitation to testify before your committee on natural gas issues concerning the Cook Inlet and Forest Oil Corporation's plans for the near future. Unfortunately, I will be out of state during the hearings, and therefore, will be unable to testify in person. I would be happy to provide written testimony, which I will submit to your office prior to November 5, 2001.

Very truly yours,

Gary E. Carlson
Senior Vice President

GEC/nc

FOREST OIL CORPORATION

310 K Street • Suite 700
Anchorage, Alaska 99501
(907) 258-8600 • (907) 258-8601 (Fax)

November 5, 2001

Senator John Torgerson, Chair
Alaska State Legislature Joint Committee on Natural Gas Pipelines
35477 Kenai Spur Hwy., Suite 101A
Soldotna, AK 99669

Fax: 907-260-3044

Dear Sirs:

On behalf of Forest Oil Corporation, I appreciate the opportunity to provide testimony to this committee regarding Cook Inlet gas development.

Forest Oil is actively engaged in exploration for gas reserves in the Cook Inlet area, as well as in other areas outside the North Slope of Alaska. Currently our operations and immediate development activities are focused on oil production; however, our strategy includes finding and developing gas reserves in our areas of activity. Forest Oil has defined multiple gas prospects on our leased acreage in the Cook Inlet area. We are interpreting geological and geophysical data, and addressing business issues necessary to develop economic scenarios, which will support exploratory drilling of the prospects.

Forest Oil is also performing regional investigations in other areas under the auspices of exploratory licenses. The result of this work will, hopefully, be to develop leads, which can be more specifically evaluated, with the final result being the development of specific drillable prospects in those regions. Gas prospects are key to these license areas.

Over the next 5 years, Forest Oil forecasts a Cook Inlet drilling budget of $225,000,000 including both development and exploratory drilling – to both oil and gas targets. Because Forest Oil is not currently a commercial natural gas supplier, we rely on public and third party estimates of proven Cook Inlet gas reserves, which place those reserves near 2.5 TCF. Both internal and published estimates of probable reserves from producing areas range from 1.0 to 2.0 TCF. Undiscovered possible reserves may range up to another 1.0 to 2.0 TCF.

The deliverability concerns that have been mentioned are tied to making the appropriate investments "just-in-time" to meet the contract demands; therefore, there could be problems if the fields are not properly managed. The current oil and gas producers in the Inlet are capable and qualified to manage this issue by adding wells or compression, as need be.

Forest Oil has been involved in permitting processes here in Alaska for the last few years and it is not an efficient system. It takes too much time, adds little or no value to the State's interest, and is

Date Modified: 11/5/01
Date Prepared: 11/2/01
nc

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destructive to industry's investment returns. In our opinion, the problem lies in the administration and regulatory agencies. We have not identified any legislative solutions to this problem at this time.

In summary, market access and pricing will drive industry investments in natural gas projects and development opportunities in the Cook Inlet area. Technically, we are convinced that the resources are there to serve the needs of Anchorage and surrounding communities for many years to come. Again, thank you for the opportunity to provide feedback to your committee.

Very truly yours,

Gary E. Carlson
Senior Vice President

GEC/nc

Date Modified: 11/5/01
Date Prepared: 11/2/01
nc

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YUKON PACIFIC CORPORATION
TRANS-ALASKA GAS SYSTEM

VIA FACSIMILE

October 31, 2001

Senator John Torgerson
35477 Kenai Spur Hwy., Suite 101A
Soldotna, AK 99669

Dear Senator Torgerson:

Thank you and Representative Green for your invitation to make a presentation during the hearing of the Joint Committee on Natural Gas Pipelines scheduled in Kenai on November 7th and 8th. I respectively decline your invitation since I feel we do not have new information or updates significant enough to justify a presentation.

We are currently implementing a reorganization of Yukon Pacific Corporation and moving our offices. The attached press release provides some particulars regarding our current activity.

Thanks again for your invitation We look forward to working with your committee in the future.

Regards,

Ward Whitmore
Director of Project Development

1400 WEST BENSON BLVD., SUITE 525 • ANCHORAGE, ALASKA 99503 • (907) 265-3100 • FAX (907) 265-3180
Yukon Pacific Corporation is a Business Unit of CSX Corporation

NEWS

CSX
CORPORATION
Corporate Communications
PO Box 85629
Richmond, Virginia 23285-5629
http://www.csx.com

Contact: Robert L. Gould
202-783-8124

WHITMORE TO HEAD UP YUKON PACIFIC

CSX CEO Says Trans-Alaska System Project, "Most Viable" Alternative for North Slope Gas

WASHINGTON, Oct. 31, 2001 – CSX Corporation Chairman & CEO, John W. Snow, announced today that Ward Whitmore, a 12-year veteran of the company's Trans-Alaska Gas System (TAGS) subsidiary, Yukon Pacific Corporation (YPC), has been named director of project development and will direct YPC's day-to-day operations. Additionally, YPC has relocated its former office at 1049 West 5th Ave., to 1400 West Benson Blvd., Suite 525, in Anchorage.

"I'm pleased to have someone with Ward's knowledge and experience directing YPC's activities, particularly at a time during which the company is moving into a new phase of operations," said Snow. "The YPC team has put together a terrific project, one that epitomizes the vision of former Governors Hammond, Hickel and Egan, all of whom saw the need to market Alaska's vast natural gas resource."

He added, "As he moves on to pursue other challenges, all of us at CSX thank Jeff Lowenfels and wish him the best in his future endeavors."

Whitmore, an Anchorage resident since 1989, joined YPC after having held several engineering-related positions with Union Pacific Resources and Phillips Petroleum. He earned a bachelor's of science degree in chemical engineering from the University of Michigan.

Under the TAGS project, natural gas would move via pipeline from the North Slope of Alaska to Valdez, where it would then be refrigerated to produce liquefied natural gas for shipment to Asia. Additionally, natural gas would flow through the interior of Alaska for access by major Alaskan population centers. Currently, YPC holds the major state and federal permits and authorizations for the 800-mile pipeline and liquefaction facility excluding wetland permits, which are presently under development.

- More -

"We believe the Trans-Alaska Gas System project is the most viable alternative to developing North Slope gas and as such will continue to press ahead with its development," said Snow. "An important aspect of the project is the ability to serve multiple markets in today's dynamic world gas market."

Snow added, "The employees of Yukon Pacific are hard at work building upon the engineering and permitting assets already in place and will continue to review a variety of configurations as they move forward with the project."

Commenting further, Snow said, "Recent trends have shown that demand for natural gas will grow rapidly. YPC has made major commitments to develop Alaska's gas and will continue to work cooperatively with the North Slope gas holders, the Governor and the legislature, the Federal government and other parties – all of whom are committed to developing this vast natural resource."

CSX Corporation, based in Richmond, Va., operates the largest rail network in the eastern half of the United States. It also provides intermodal, domestic container shipping and global container terminal operations.

###

CSX's Internet Address: http://www.csx.com

ALASKA GASLINE PORT AUTHORITY
550 West 7th Avenue, Suite 1850
Anchorage, Alaska 99501
(907) 278-7000\ fax:(907) 278-7001
ddengel@ci.valdez.ak.us

November 1, 2001

Senator John Torgerson, Chair
Joint Committee on Natural Gas Pipelines
35477 Kenai Spur Highway, Suite 101A
Soldotna, Alaska 99669

Dear Senator Torgerson,

Thank you for your invitation to speak before your committee next week. At this time the Port Authority does not have anything new to present. We are continuing to work with possible purchasers of Alaska's North Slope natural gas.

The Port Authority will be having its annual meeting later this month. I will let you know what the date has been set. If you would like to attend and speak before the Board you will certainly be welcomed.

Again, thank you for your invitation to speak before your committee. We will keep you apprised of the status of the Port Authority.

Sincerely,

David Dengel
Executive Director

Gas-Pro Alaska LLC
1909 So. Harvard Ave., Tulsa, Oklahoma 74112
Phone (918) 748-8775 ★ Fax (918) 748-8891

Part of the NORTHSTAR Energy Group

November 6, 2001

Alaska State Legislature
Joint Committee on Natural Gas Pipelines
Senator John Torgerson, Chairman
Rep. Joe Green, Vice-Chair

Ladies and Gentlemen:

This letter is in response to the Committee's questions regarding Gas-Pro Alaska's plans to develop gas reserves in Cook Inlet. Taking the questions in order:

1) Provide the committee with an update of Gas-Pro's activities related to south-central gas field operations.

Gas-Pro is planning to continue the development of the North Fork Field. Specific activities include rebuilding the NF 41-35 wellhead and conducting a mechanical integrity test of the well and; flow testing the well to demonstrate productivity and quantify proved recoverable reserves. As a separate project, Gas-Pro is still permitting an offset well to the NF 41-35. The offset well is intended to prove up additional gas reserves in the Tyonek and possibly test the oil potential of the deeper Hemlock conglomerate. Gas-Pro is also working to identify and lease other potentially productive structures along the same general trend as North Fork.

2) What, if any, expansion plans are being made in the event that a natural gas supply is made available from the North Slope?

Gas-Pro assumes that a pipeline bringing North Slope gas to the Cook Inlet market would also provide access for Cook Inlet gas to markets in the Lower 48.

3) What is your current assessment of proven developed gas reserves, proven undeveloped gas reserves, and unproven probable gas reserves in the Cook Inlet? What is your current assessment of undiscovered gas resources in the Cook Inlet? What are your current explorations plans within and outside known producing fields in the Cook Inlet?

Gas-Pro's assessments of PDP and PUD gas reserves in the Cook Inlet Basin are based on studies released by the Alaska Department of Natural Resources, the Alaska Oil and

Gas Conservation Commission and GeoQuest (study commissioned by Marathon Oil Company and Phillips Petroleum). Specifically, Proved Developed Producing (PDP) reserves are 2.93 TCF. Proved Undeveloped reserves are 858.9 BCF. Total proved reserves are 3.79 TCF

Gas-Pro has not assessed "unproven probable" reserves in the Cook Inlet Basin but does not disagree with the USGS estimate of 2.3 TCF of reserves *yet to be discovered* in the Cook Inlet Basin. At North Fork alone, Gas-Pro believes at least 220 BCF of recoverable reserves are contained in Beluga and Tyonek reservoirs. Gas-Pro believes that there will be more significant gas discoveries in the Cook Inlet Basin as exploration continues in south-central Alaska.

Gas-Pro is studying other prospects along the North Fork trend. Some of these will require additional seismic to delineate.

4) What is your proposed south-central drilling budget for the next five years?

Gas-Pro anticipates drilling up to 20 wells over the next five years at an estimated cost of $60MM.

5) What is your current assessment of south-central demand for gas over the next ten to twenty years? If you have pessimistic, optimistic and base cases, please generally describe each case.

Gas-Pro subscribes to projections by the University of Alaska Institute for Social and Economic Research that demand for natural gas in south-central markets will grow at between 1% and 2.5% per year for the foreseeable future. New industry requiring large volumes of natural gas and construction of a new LNG plant, possibly at Homer, would significantly boost demand.

6) We have heard that "deliverability", the ability to meet peak winter demand, may be a problem soon. Please discuss whether you see deliverability constraints in the next 10 years. Please discuss what can be done to reduce any deliverability problem.

Gas-Pro's view of the deliverability issue is based on statements by Enstar and others that deliverability shortfalls are anticipated within the next few years barring any significant additions to supply. Gas-Pro believes a potential gas deliverability crunch is looming and that immediate steps should be taken to avert such an event.

It is Gas-Pro's position that the best way to alleviate future gas shortages in the south-central market is to expedite development of known fields such as North Fork and Falls Creek in the southern Cook Inlet Basin by encouraging pipelines such as the one being

considered from Kenai to Homer. Additionally, the State should continue to encourage exploration for new reserves on the southern Kenai Peninsula and other under-explored areas of the Cook Inlet Basin

7) Finally, do you have any recommended state legislation the committee should consider to advance the development of natural gas related industry within the state?

Gas-Pro believes that streamlining the permitting process for drilling wells would be very helpful.

Gas-Pro appreciates this opportunity to voice its opinions on the current state of the natural gas industry and its future in south-central Alaska. Please feel free to contact us with any questions at the above numbers.

Sincerely,

J. Lawrence Snead

J. Lawrence Snead
Gas-Pro Alaska LLC

PHILLIPS 66

PHILLIPS Alaska, Inc.
A Subsidiary of PHILLIPS PETROLEUM COMPANY

Cook Inlet Gas Considerations

Testimony to Joint Committee on Natural Gas Pipelines

By
Scott Jepsen
Manager, Cook Inlet Group

November 8, 2001

Mr. Chairman, for the record, my name is Scott Jepsen. I am employed by Phillips, as the Manager for our Cook Inlet assets. I reside in Anchorage, Alaska. Thank you for giving Phillips an opportunity to provide its perspective on the matters requested in the attachment to your October 22, 2001 letter.

For clarity, my testimony is structured in question and answer format, addressing the 10 questions asked in your letter. These answers also provide our overall perspective on Cook Inlet, as requested in your letter.

1) Provide the committee with an update on Phillips' LNG facility activities and its Cook Inlet gas field operations.

Phillips is the operator of the Beluga River Field and the North Cook Inlet Unit (NCIU). Phillips' interest in the Beluga River Field is 33% and in the NCIU is 100%. The Beluga Field primarily provides gas to the local utility market with some sales of gas to the Agrium urea plant. Total gross yearly production out of Beluga is approximately 38 BCF per year. Gas from the North Cook Inlet Unit is produced from the Tyonek Platform. Currently, 100% of the gas from Tyonek is used to supply the Phillips portion of the feed requirements to the Phillips/Marathon LNG plant. The yearly production from the NCIU is approximately 53 BCF. Phillips' plan for these fields is to maintain deliverability within economic constraints. Phillips also has a 50% interest in the Moquawkie gas field, a small, one well, undeveloped, 1998 discovery on the west side of Cook Inlet near the Beluga River Field.

The Kenai LNG plant is jointly owned by Phillips (70%) and Marathon (30%). Total feed to the plant from Phillips and Marathon is approximately 77 BCF per year. The plant produces on average about 1.5 million tons per annum of liquefied natural gas which is sold to Japanese utilities. Our current plans do not envision any significant changes to the operation of the LNG facility.

2) What is the expected length of time Phillips plans to continue current levels of LNG production under the most recent production estimates from natural gas reserves in the Cook Inlet?

On April 2, 1999, Phillips and Marathon were granted a renewal of the export license for the Kenai LNG plant for the period April, 2004 to March, 2009 by the U.S. Department of Energy, Office of Fossil Fuels. For that renewal, a thorough analysis of reserve adequacy was conducted and substantial hearings were held. The results of that process demonstrated that reserve capacity was sufficient for LNG exports to continue through the approved period. It was also found that export was consistent with the public interest and would not result in a local or regional gas supply shortfall on an annual basis.

Phillips hopes to operate the Kenai LNG plant well past 2009. However, it is premature to determine whether we will seek another extension, but if we do, there will be adequate gas reserves to do so, as well as provide for the state's needs.

3) What, if any, expansion plans are being made in the event that a natural gas supply is made available from the North Slope?

Phillips is focussing its ANS gas commercialization efforts on a pipeline to the Lower 48/Canadian markets.

On the general topic of LNG, we would also note that Phillips has been part of the Alaska North Slope LNG Sponsor Group since its inception in 1999. A detailed review of the Sponsor Group work was given to the Senate Resources committee in April, 2001. That review indicated that the Nikiski area and a pipeline from Prudhoe Bay would provide a technically feasible and permittable LNG plant site/route configuration. However, a cost competitive, economically viable Alaska LNG project has yet to be identified.

4) Do you plan to apply for an extension of your LNG export authorization past 2009 if North Slope gas is not available? Is your answer different if North Slope gas were available?

As mentioned in my previous answer, Phillips would like to extend the operation of its LNG operation past 2009, if the dedicated gas supply available to Phillips and Marathon in Cook Inlet allows us to do so. However, we do not see that an export license extension is necessarily contingent on ANS gas being available in the Cook Inlet area.

5) What is your assessment of the Japanese LNG market?

The East Asian LNG market is fiercely competitive and likely to continue to be so throughout the remainder of the decade. In round numbers, we see about 60 to 75 million metric tons per year of potential new LNG supply chasing after 20 to 40 million metric tons per year of new LNG demand through 2010. As a result, recently we have seen prices for new contracts trending downward and pressure for shorter contract periods.

This reinforces the difficulties that an Alaskan LNG project faces in the East Asian market over the next decade. While the market for new LNG is expected to grow, there is an over abundance of lower cost supply and in smaller increments compared to new LNG that would be delivered from Alaska.

That said, Phillips will continue to monitor and evaluate this situation for possible opportunities for Alaskan LNG.

6) What is your current assessment of proven developed gas reserves, proven undeveloped gas and unproven probable gas reserves in the Cook Inlet? What is your current assessment of undiscovered gas resources in the Cook Inlet?

For competitive reasons, Phillips does not release its internal assessment of reserves for fields or basins. However, we can cite several published reports that provide estimates of Cook Inlet reserves. Schlumberger-Geoquest performed a study for Phillips/Marathon in support of the LNG export license renewal effort. The Schlumberger-Geoquest report

estimated that, as of 1/1/98, total remaining proven reserves in Cook Inlet stood at 3.3 TCF (cited in the application to Amend Authorization to Export Liquefied Natural Gas, Department of Energy, Office of Fossil Energy). Adjusting for estimated production volumes since then, 1/1/2001 proven reserves stood at around 2.7 TCF. The USGS has also estimated probable reserves at 1 TCF and possible reserves at 1.4 TCF (as reported in "A Review of Cook Inlet Natural Gas Supply and Demand", Northern Economics, 2001, p.8).

With regard to Phillips' assessment of undiscovered gas resources in Cook Inlet, one has to first step back a bit from the numbers. While the estimate of proven reserves is fairly precise, the assessment of possible or potential reserves is less precise. The only real significance of the USGS estimate is that it indicates we probably have not found everything there is to be found in Cook Inlet. The only way to know for sure is through drilling. Because of the historic overabundance of gas in Cook Inlet, drilling activity targeted at gas has not been as high as it might have been. The supply and demand relationship is starting to turn now, with the extreme supply overabundance relative to demand dropping to a level more comparable to the Lower 48. While some see this as a matter of concern, it is premature to think that the market will not react and fill in the supply opportunities as they arise. From an exploration and production point of view, this is really a time for optimism, not pessimism. Let me explain.

By 1970, gas reserves in Cook Inlet stood at about 8 trillion cubic feet (TCF) and production was about 145 billion cubic feet per year: thus the Reserves to Production ratio (R to P ratio) was about 55 years. As would be expected with such a high ratio, there was little incentive to explore for gas, since it would either be a long time before revenues would be realized for the additional, discovered gas or the gas would have to be sold at inordinately low prices.

Over time, the known Cook Inlet reserves have been slowly consumed. As indicated above, reserves are about 2.7 TCF, consumption is about 215 bcf/yr and the R to P ratio is just under 13 years. Theoretically, this would suggest that developed reserves will be exhausted in about 2014. However, in reality, this is a very normal situation in the natural resource industry. For example, the R to P ratio of the L-48 is about 7 years and it has roughly been at 7-10 years, with a slight decline, for the last 20 years. New resources have been added at about the same level as consumption. The market for gas and the increased demand spurs exploration and development.

In the past, the overabundance of gas supply in Cook Inlet has served as a disincentive for exploration. However, for the first time in about 30 years, a company that finds new gas can actually sell at least some of its potential production at a price that may yield acceptable rates of return.

In fact, Phillips believes we are beginning to see the early signs of a new phase of exploration and discovery. We have seen public announcements showing that gas activity has begun to pick up. Phillips and Anadarko had success in finding gas in the Moquawkie Field. We also note the public announcement that Nikolai Creek No. 3 has

been successfully recompleted and that Northstar Energy Group proposes a well to tap the North Fork gas field. Marathon and Unocal are actively exploring throughout the Kenai Peninsula. There is clearly a "renewal" of interest in gas exploration and production in the Cook Inlet area, and the results of that effort are beginning to be seen.

Exploration for oil is also on an 'upswing'. Forrest Oil has made an oil discovery at Redoubt Shoal and Phillips is drilling an oil exploration well near Anchor Point. While these oil fields may not add significant gas reserves, they do provide infrastructure that could lower the economic hurdles for additional exploration and development.

On the price side, Enstar has shown willingness in its more recent contracts to tie gas prices to widely accepted gas indices such as Henry Hub. While Cook Inlet is not connected to the Lower 48, receiving Lower 48 prices or better for Cook Inlet gas makes it easier to evaluate gas plays in Cook Inlet relative to other options available to potential investors.

Beyond these basic observations, there are other reasons for prudent optimism. First, seismic technology has progressed and should significantly improve exploration chance factors. Second, there are more players, some new, in the picture. Besides the historical players such as Unocal, Marathon, Chevron and Phillips, companies such as Northstar Energy, Forrest Oil, Anadarko, Aurora, Crosstimbers, Pelican Hill and Escopeta are investing in the Inlet. Clearly, the more players, the more likely that wells will be drilled and discoveries made.

In looking at Cook Inlet as typical of any large, prolific resource basin, there are a couple of characteristics that are common to all of these types of basins. First there is invariably a distribution of field sizes in basins that have been well explored. Second, there are normally cycles of discoveries based upon technology or play concepts.

I want to first take the topic of field size distribution. We know that, typically, naturally occurring phenomena, like hydrocarbon accumulations are distributed in what is technically defined as a log normal distribution. Simplistically, there should be a few giant fields and an ever increasing number of smaller fields. In Cook Inlet, almost all of the currently known reserves are contained in what industry would consider large or giant gas fields. These are fields with more than 1 TCF of initial reserves. These fields have long been regarded as 'accidental discoveries' made while exploring for oil. There has also been a sprinkling of relatively small discoveries in the 50 BCF or less range, which are an inevitable result of the exploration wells that have been drilled. What are undiscovered are the expected field sizes in between. As the incentive to explore for gas in Cook Inlet increases, there is a high likelihood that explorers will start to find these middle-sized fields. With higher prices and increased infrastructure, many of these fields could be economic and in aggregate, could contain relatively large amounts of gas.

Discovery cycles are also a common characteristic of basins like Cook Inlet. Typically, a number of discoveries are initially made in a basin based upon a particular geologic concept, often followed by a period of few discoveries. Almost invariably, there is a new

concept or a new technology that leads to a new round of discoveries. An example of this on the North Slope is the recent successes in NPRA. Although it may seem counter intuitive because of the long history of production in Cook Inlet, Cook Inlet may just be starting to come out of its first phase of discoveries. While many of the obvious targets in Cook Inlet have been drilled and technology will play a part in new exploration concepts, the lack of a market in Cook Inlet has kept operators from drilling some long known play concepts. This is another reason for optimism: there are drill ready prospects already out there.

In public forums, we often hear the concern that the Cook Inlet is "running out of gas". It strikes us that this assertion basically ignores the role that exploration is very likely to play in Cook Inlet. As long as the industry has incentive to drill, we believe the next five to ten years will yield much about the potential of the basin.

7) What are your current exploration plans within and outside known producing fields in the Cook Inlet? What is your proposed Cook Inlet drilling budget for the next five years?

As I mentioned in my response to the last question, Phillips is drilling an oil exploration well near Anchor Point. For proprietary reasons, Phillips does not release its specific exploration plans or strategies. In general, however, we will look at any Cook Inlet drilling opportunity on a case by case basis and determine if it competes with Phillips' world-wide opportunities, including those on the North Slope.

8) What is your current assessment of South-central demand for gas over the next ten to twenty years? If you have pessimistic, optimistic and base cases, please generally describe each case?

The area utilities and the University of Alaska at Anchorage (UAA) generally provide demand forecasts for the South Central Area on an ongoing basis. In general, we do not see any significant variances around their forecasts at this time that would influence our business strategies.

9) We have heard that "deliverability", the ability to meet peak winter demand, may be a problem soon. Please discuss whether you see deliverability constraints in the next ten years. Please discuss what can be done to reduce any deliverability problem.

Gas demand in the Cook Inlet is very seasonal. For a period of a few days to perhaps several weeks in the winter, consumption peaks perhaps 30 – 40 % higher than that for the rest of the year. However, meeting these peak demands is not so much a function of reserves as a function of the capacity of wells and delivery facilities. To meet the peak winter demand, investments must be made that are underutilized at other times of the year. For example, in the Lower-48, Canada and Europe, investments have been made for "peak shaving": facilities specifically designed to supply gas during seasonal high demand. Common types of peak shaving are underground storage in converted reservoirs, LNG storage and facility capacity expansions such as additional compression. Typically, these investments are made by the utilities, which have the ultimate responsibility to meet

the peak gas demand of consumers. While such peak shaving facilities are common elsewhere, due to high deliverability, there has been little incentive for them in Cook Inlet.

Phillips believes that the tension of not over-investing, yet still meeting peak demands is something that the marketplace can and will ultimately solve through a variety of strategies. As a practical matter, as has been illustrated in numerous markets around the world, investments by the producers to increase peak deliverability must be balanced with development of true peaking facilities. Further, we understand Enstar has agreements in place with Unocal and Marathon to divert gas supplies to meet local peak requirements, should the need arise. In addition, Phillips is committed to working in support of Enstar's efforts to ensure that the needs of the community during critical periods are met.

10) Finally, do you have any recommended state legislation the committee should consider to advance development of natural gas related industry within the state?

Clearly, more frequent and wider lease sales and expedited permitting is an excellent policy. In addition, State support of increased federal lease sales in the potentially gas prospective lower Cook Inlet would also be appropriate.

Mr. Chairman this concludes my testimony. Thank you for the opportunity to present Phillips' views on Cook Inlet gas. I would be happy to answer any questions you may have.

Agrium

Alaska Cook Inlet Natural Gas Competitiveness

Alaska Joint Committee on Natural Gas Pipelines
November 2001

Chris W. Tworek
Vice President, Supply Management
Agrium Inc.

Agenda

- The Company
- Kenai Nitrogen Operations
- World Competitiveness
- The Alaskan Situation
- Partners in Growth

Agrium

The Company

- **Agrium is One of World's Largest Fertilizer Manufactures**
  - *14 Production Facilities*
  - *11 million tons*
- **Second Largest Ag. Retailer in N.A.**
  - *226 Outlets*
- **Annual sales exceed US $2.0 Billion**



Agrium

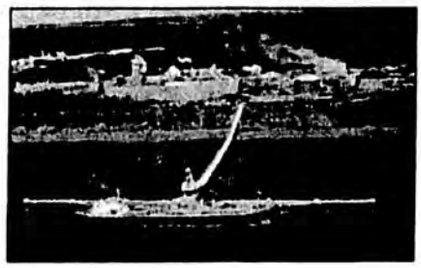
The Company

- **World Scale Facilities**
  - *High Efficient / Low Cost Producer*
  - *Strategically Located Near Key Markets*
  - *Tidewater Access to International Markets*
- **Highly Skilled Workforce**
  - *More Than 5000 Employees World Wide*
- **Committed to Safety & The Environment**

Agrium

Kenai Nitrogen Operations

- **Products**
  - *6% of N.A. Nitrogen Production*
    - Ammonia - 700,000 (net) tons
    - Urea - 1.1 million tons



- **50-55 BCF/yr of Natural Gas Consumption**
- **Employees**
  - *300 Full-Time, Highly Skilled*
  - *30 Contractors on average*

Agrium

Kenai Nitrogen Operations

- **Primary Markets**
  - *Ammonia – Pacific Rim*
  - *Urea – Mexico, South America, Taiwan and Korea*
- **Competition**
  - *FSU, South America, Trinidad and Pacific Rim*
  - *Many new plants built in last decade*
  - *World product prices tend to be capped by trapped gas economics*

Agrium

Kenai Nitrogen Operations

- **Community Investments**
  - *Large Local Employer*
    - 300 Highly Skilled Employees
  - *Donations & Sponsorships*
    - Caring for The Kenai
    - United Way
    - Challenger Learning Center
    - Boys & Girls Club, etc.
  - *Commitment to Safety & Environment*

Economic Benefits
– over 130 M$/yr



*Includes Royalties

Agrium

World Competitiveness

- **Nitrogen is a World Traded Commodity**
  - *Easiest way to monetize & transport gas reserves*
    - $15/t to 50/t ocean freight
- **Recent high N.A. gas prices made N.A. Nitrogen production uneconomic**
  - *N.A. Produces 14% of World's Nitrogen**
    - Up to 50% of N production shut-in at peak
    - U.S. Nitrogen imports doubled
    - Gas producers lost sales for all industrial products

* 20 M tons N - Ammonia, Urea, Nitrate, UAN solutions
(2.0 - 2.3 BCF/d natural gas consumption)

Agrium

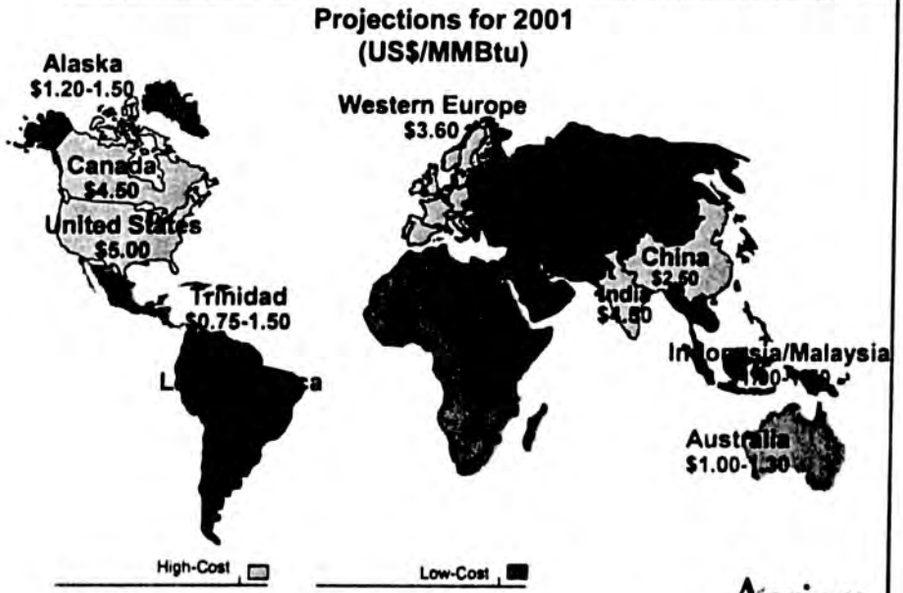
Importance of Natural Gas

- Ammonia takes 33.5 MMBTU per ton
- Gas is 75 – 90% of ammonia production cost

	World	Recent Prices	N.A.
Feed (MMBTU/ton)	33.5		33.5
Gas Price ($/MMBTU)	x 1.00		x 5.00
Variable Feed /ton	$34		$168
Cash Conversion /ton	$25		$25
Cash Production /ton	**$59**	←$100-190→	**$193**

Agrium

World Industrial Gas Cost Comparison



Source: CERA, BJ&A, Fertecon, Agrium

Agrium

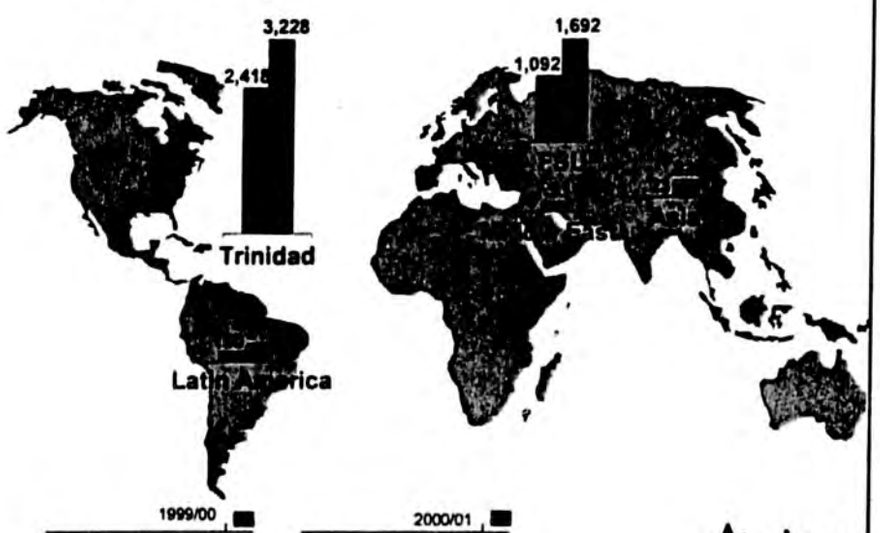
The North America Balance

2001 vs 2000 (Crop Year)	Nitrogen (million st/yr)
Normal Production	**19**
Production reductions	(3)
Increased imports	3
Supply	**19**
Market Demand	18
Inventory Build	**1.0**

Agrium

Major Ammonia Exporters to North America

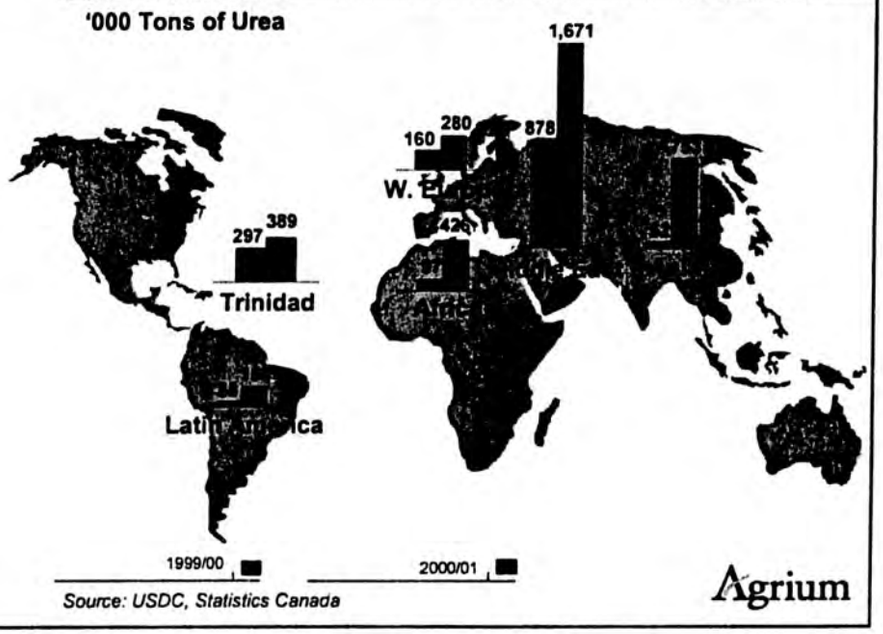
'000 Tons of NH_3



Source: USDC, Statistics Canada

Agrium

Major Urea Exporters to North America



Source: USDC, Statistics Canada

Agrium

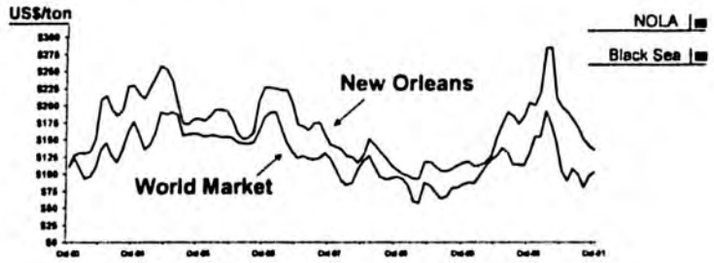
Affect of High N.A. 2001 Gas Pricing

- **Plant Shut Downs**
  - *Up to 50% at Peak Gas Pricing*
- **Loss of Market Share**
  - *Imports almost doubled*
- **$ 4-5 gas cannot compete against $1 gas**
  - *Offshore competition won*
  - *Gas Producers lost sales*
    - N was about 0.75 of 3-5 BCF/d industrial demand destruction
    - High prices were not sustained

Agrium

The Alaskan Situation

- **Cook Inlet Products are exported**
  - *Fertilizer and LNG compete globally*
  - *New industries (e.g. gas to liquids) will also have to compete internationally*
  - *Our prices are based on international markets not lower 48*



Source: Green Markets, Blue Johnson

Agrium

The Alaskan Situation

- **Jones Act restricts exports to lower 48**
  - *Act requires U.S. Flag vessels to move products among U.S. ports*
- **Cook Inlet Fertilizer is forced to go off-shore**
  - *No U.S. flag ammonia vessels left*
  - *Urea limited to 1-2 sea going barge*

Agrium

Partners in Growth

Expansion Opportunity

- *Based On Cook Inlet Advantages:*
  - Close to Pacific Rim markets
  - Good Business Climate & Skilled Workforce
  - World Scale Plant
    - Needs to expand to stay competitive
- *Agrium uses 50-55 BCF/yr today*
  - Expansion plans add up to 30 BCF/yr
  - Current base supply needs long term extension

Agrium

Partners in Growth

Expansion Benefits to Alaska

- *Grows Current Local Economic Contribution of $130 M annually*
- *Increases Sales/Exports*
- *Expands skilled employment*
- *Allows Greater Community Investment*
- *Increases Tax Base*
- *Encourages Gas Exploration*
- *Opens Up Other Industries to Export Markets*

Must Be Based on Competitiveness

- *Reliable and Internationally Competitive Supply of Gas*

Agrium

Partners in Growth

- **Some Possible Solutions**
  - *Spur from Alaska Gas Pipeline is long term advantageous solution*
  - *Cook Inlet has immediate additional gas potential*
    - Anchorage Economic Development Corp Report: 1-3 TCF to be found
    - Coal Bed Methane: 8 – 250 TCF
    - Escopeta: 5-18 TCF

Agrium

Partners in Growth

- **Agrium willing to work with State and Producers to encourage development:**
  - *Pre-investment on appropriate risk/reward:*
    - Pre-bought gas production
    - Infrastructure investment (e.g. pipelines)
    - Exploration and drilling partnerships
  - *Exploration Royalty Relief*
  - *Ongoing royalties based on actual contracts or weighted average sales prices*
  - *Purchase of State Royalty Gas*
  - *North Slope Spur Line*

Agrium

In Closing...

Successful partnering will:

- *Continue Alaska's development for all sectors*
  - Building Cook Inlet strengthens base for mega projects such as Alaska Pipeline
- *Contribute to Alaska's export position*
- *Increase Agrium's annual $130 M plus contribution to local economy*

Agrium

Agrium

November 2001

FRAN ULMER
LIEUTENANT GOVERNOR
STATE OF ALASKA

September 4, 2001

Scott R. Heyworth
PO Box 100531
Anchorage, AK 99510

Dear Scott:

The initiative application for a bill entitled, "The All-Alaskan Gasline Initiative", was submitted to our office for review under AS 15.45.070. The application was forwarded to the Division of Elections for verification of signatures and the Department of Law for review.

Enclosed for your information is the Department of Law's opinion regarding this bill and a copy of the petition statistics report for **01GSLN** as prepared by the Division of Elections.

The Division of Elections has verified that the application does have a sufficient number of sponsors to qualify for circulation of a petition. The Department of Law has concluded that the initiative application does comply with AS 15.45.030 and AS 15.45.040. Consequently, the above referenced initiative application has been certified as being in the proper form under the provisions of AS 15.45.010 through AS 15.45.070, and Article XI of the Alaska Constitution. The official certificate for the application is enclosed.

As Lieutenant Governor and in accordance with AS 15.45.090 (2), it is my duty to prepare an impartial summary for the petition booklets. The following is the suggested petition summary:

Initiative on Gas Pipeline Development Authority

This bill would create the Alaska Natural Gas Development Authority (Authority) as a public corporation of the State. The Authority would acquire and condition North Slope natural gas, and construct a pipeline to transport the gas. The Authority's powers would include buying property or taking it by eminent domain, and to issue state tax-exempt revenue bonds. The gasline route would be from Prudhoe Bay to tidewater on Prince William Sound and the spur line from Glennallen to the Southcentral gas distribution grid. The Authority would operate and maintain the gas pipeline, ship the gas, and market the gas.

P.O. Box 110015 Juneau, Alaska 99811-0015 Phone (907) 465-3520 Fax (907) 465-5400

POLITICAL OPINION SURVEY

IVAN MOORE RESEARCH
TEL: 278-4600
JUNE 23/24, 2001

MUNICIPALITY OF ANCHORAGE ONLY
252 RESPONSES

Hello, my name is _____ and I'm calling for Ivan Moore Research, an Alaska public opinion research firm. We're conducting a public opinion survey that should take about 2 minutes. Your opinions are important to us, and we'd appreciate your participation if that's OK with you, and of course your responses will be completely confidential.

S1. Is this a residential telephone?
IF "YES", CONTINUE...
IF "NO", TERMINATE...

S2. Are you registered to vote in the Municipality of Anchorage?
IF "YES", CONTINUE...
IF "NO", ASK FOR OTHER VOTER...

1. What is your registered party affiliation?

	PARTY AFFILIATION:	
	Count	%
Democrat	48	19.0%
Republican	81	32.3%
Other party/No party	123	48.7%

2. When it comes to politics, do you consider yourself to be a conservative, a moderate or a progressive?

	POLITICAL IDEOLOGY:	
	Count	%
Conservative	99	39.4%
Moderate	108	42.9%
Progressive	45	17.7%

There has been some discussion lately about thetransportation of North Slope natural gas to market. Which of the following two proposals do you support most? A route that travels south from the North Slope to Fairbanks then east along the Alaska Highway to Canada and down to the Lower 48, or a route that follows the Alaska Pipeline corridor south to Valdez where it is converted from gas to liquid natural gas and is shipped out by tanker?

"(The All-Alaskan Gasline Initiative) An Act establishing the Alaska Natural Gas Development Authority, to maximize revenues for Alaska and jobs and gas for Alaskans."

BE IT ENACTED BY THE PEOPLE OF THE STATE OF ALASKA:

* Section 1. The uncodified law of the State of Alaska is amended by adding a new section to read:

FINDINGS AND INTENT. (a) The people find that

(1) The Phillips-Marathon liquefaction facility at Nikiski has been supplying Cook Inlet natural gas to Japan and Southcentral Alaska at great profit and without interruption since 1969;

(2) Cook Inlet gas supplies are dwindling rapidly with shortfalls anticipated as early as the winter of 2003;

(3) Alaska's North Slope contains vast proven reserves of natural gas that have been known for at least 25 years but have never been developed;

(4) these gas resources have never been offered for sale, because there has been no way to transport them to market;

(5) multiple markets in North America and Asia have recently expressed an interest in receiving a proposal from Alaska for the purchase of Alaska gas;

(6) if developed, these natural gas resources could represent substantial economic benefits to Alaskans in jobs, state revenue, and gas for Alaska citizens and businesses;

(7) the major North slope leaseholders have competing gas reserves in other parts of the world vying for the same markets, creating a conflict of interest for them in advancing the sales of Alaska gas;

(8) the North slope Producers agreed in 1991 to strand North Slope gas until at least 2005;

(9) given the producer's conflicts of interest and their historic refusal to make North Slope natural gas available it may be necessary to take the gas back;

(10) the permits necessary for an Alaskan gasline project have been pledged to the Alaska Natural Gas Development Authority, operating as a port authority, to facilitate the development of the project;

(e) The authority may not be terminated as long as it has bonds, notes, or other obligations outstanding.

Sec. 41.41.020. Authority governing body. (a) The authority shall be governed by a board of directors consisting of seven members from the general public appointed by the Governor and confirmed by the legislature.

(b) The board shall annually elect a chair, and may elect other officers, from among its members.

Sec. 41.41.030. Term of office. (a) The members of the board shall be appointed for terms of three years, and they may be reappointed.

(b) The terms of the members shall be staggered.

Sec. 41.41.040. Removal and vacancies. (a) The governor may remove a member of the board from office. A removal must be in writing and must state the reason for the removal. A member who is removed may not participate in board business and may not be counted for purposes of establishing a quorum after the member receives written notice of removal. A member who is removed is not entitled to honoraria, per diem, or travel expenses authorized under AS 41.41.060 for work performed after the member receives the written notice of removal.

(b) The governor shall promptly fill a vacancy on the board by appointment. An appointee to a vacancy shall hold office for the balance of the term for which the appointee's predecessor on the board was appointed.

(c) A vacancy on the board does not impair the authority of a quorum of the board to exercise all the powers and perform all the duties of the board.

Sec. 41.41.050. Quorum and voting. Four members of the board constitute a quorum for the transaction of business and the exercise of the powers and duties of the board. Action may be taken only upon the affirmative vote of a majority of the full membership of the board.

Sec. 41.41.060. Compensation of board members; per diem and travel expenses. Members of the board are entitled to per diem and travel expenses authorized for boards and commissions under AS 39.20.180.

Sec. 41.41.070. Authority staff. (a) The board may employ and determine the salary of a chief executive officer.

(b) The chief executive officer may, with the approval of the board, select and employ additional staff as necessary.

Sec. 41.41.130. Tax exemption. The security instruments issued by the authority, the transfer of the security instruments, and the income on the security instruments are exempt from all taxes and assessments in the state.

Sec. 41.41.140. Political activities. The resources of the authority may not be used to finance or influence political activities.

Sec. 41.41.150. Public access to information. (a) Information in the possession of the authority is a public record, except that information that discloses the particulars of the business or affairs of a private enterprise or investor is confidential and is not a public record for purposes of AS 40.25.110 - 40.25.140. Confidential information may be disclosed only for the purposes of an official law enforcement investigation or when its production is required in a court proceeding.

(b) The restrictions of (a) of this section do not prohibit the publication of statistics presented in a manner that prevents the identification of particular reports, items, persons, or enterprises.

Article 2. Powers of the Authority.

Sec. 4141.200. Powers of the authority. In furtherance of its corporate purposes, in addition to its other powers, the authority may

(1) sue and be sued;

(2) adopt a seal;

(3) adopt, amend, and repeal bylaws and regulations;

(4) make and execute contracts and other instruments;

(5) in its own name acquire property, lease, rent, convey, or acquire real and personal property; a project site or part of a project site may be acquired by eminent domain;

(6) acquire natural gas supplies;

(7) issue bonds and otherwise incur indebtedness in accordance with AS 41.41.300 - 41.41.410 in order to pay the cost of a project;

(8) accept gifts, grants, or loans from and enter into contracts or other transactions regarding gifts, grants, or loans with a federal agency or an agency or instrumentality of the state, a municipality, private organization, or other source;

(9) enter into contracts or agreements with a federal agency, agency or instrumentality of the state, municipality, or public or private individual or entity, with respect to the exercise of its powers;

coupons, exchangeable for bonds or bond anticipation notes when these definitive bonds or bond anticipation notes have been executed and are available for delivery.

(e) Bonds or bond anticipation notes may be sold in the manner and on the terms the authority determines.

(f) If an officer whose signature or a facsimile of whose signature appears on a bond, note, or coupon attached to them ceases to be an officer before the delivery of the bond, note, or coupon, the signature or facsimile is valid to the same extent as if the officer had remained in office until delivery.

Sec. 41.41.310. Covenants. In a resolution of the authority authorizing or relating to the issuance of bonds or bond anticipation notes, the authority has power by provisions in the resolution that will constitute covenants of the authority and contracts with the holders of the bonds or bond anticipation notes to

(1) pledge to a payment or purpose all or a part of its revenues to which its right then exists or may thereafter come into existence, and the money derived from the revenues, and the proceeds of bonds or notes;

(2) covenant as to the use and disposition of payments of principal or interest received by the authority on loans or other investments held by the authority;

(3) covenant as to establishment of reserves or sinking funds and the making of provision for and the regulation and disposition of the reserves or sinking funds;

(4) covenant with respect to or against limitations on a right to sell or otherwise dispose of property of any kind;

(5) covenant as to bonds and notes to be issued, and their limitations, terms, and conditions, and as to the custody, application, and disposition of the proceeds of the bonds and notes;

(6) covenant as to the issuance of additional bonds or notes, or as to limitations on the issuance of additional bonds or notes and the incurring of other debts;

(7) covenant as to the payment of the principal of or interest on the bonds or notes, as to the sources and methods of the payment, as to the rank or priority of the bonds or notes with respect to a lien or security, or as to the acceleration of the maturity of the bonds or notes;

(8) for the replacement of lost, stolen, destroyed, or mutilated bonds or notes;

(b) This section does not apply to the issuance by the authority of refunding bonds or to the issuance by the authority of bonds the proceeds of which are intended to be used to refinance the loans held by the authority.

Sec. 41.41.330. Independent financial advisor. In negotiating the private sale of bonds or bond anticipation notes to an underwriter, the authority may retain a financial advisor. A financial advisor retained under this section must be independent from the underwriter.

Sec. 41.41.340. Validity of pledge. (a) The pledge of assets or revenue of the authority to the payment of the principal or interest on an obligation of the authority is valid and binding from the time the pledge is made, and the assets or revenue become immediately subject to the lien of the pledge without physical delivery or further act. The lien of a pledge is valid and binding against all parties having claims in tort, contract, or otherwise against the authority, irrespective of whether those parties have notice of the lien of the pledge.

(b) This section does not prohibit the authority from selling assets subject to a pledge, except that a sale may be restricted by the trust agreement or resolution providing for the issuance of the obligations.

Sec. 41.41.350. Capital reserve funds. (a) For the purpose of securing one or more issues of its obligations, the authority may establish one or more special funds, called "capital reserve funds," and shall pay into those capital reserve funds (1) money appropriated and made available by the state for the purpose of those funds, (2) proceeds of the sale of its obligations, to the extent provided in the resolution or resolutions of the authority authorizing their issuance, and (3) other money that may be made available to the authority for the purposes of those funds from another source. All money held in a capital reserve fund, except as provided in this section, shall, subject to appropriation, be used as required solely for the payment of the principal of obligations or of the sinking fund payments with respect to those obligations; the purchase or redemption of obligations; the payment of interest on obligations; or the payment of a redemption premium required to be paid when those obligations are redeemed before maturity. However, money in a fund may not be withdrawn from that fund at any time in an amount that would reduce the amount of that fund to less than the capital reserve requirement set out in (b) of this section, except for the purpose of making, with respect to those obligations, payment, when due, of principal, interest, redemption premiums, and the sinking fund payments for the payment of which other money of the authority is not available. Income or interest earned by, or

resolution, either at law or in equity, may enforce all rights granted hereunder or under the trust agreement or resolution, or under another contract executed by the authority under this chapter, and may enforce and compel the performance of all duties required by this chapter or by the trust agreement or resolution to be performed by the authority or by an officer of it.

Sec. 41.41.370. Negotiable instruments. All obligations and interest coupons attached to them are negotiable instruments under the laws of this state, subject only to applicable provisions for registration.

Sec. 41.41.380. Obligations eligible for investment. Obligations issued under the provisions of this chapter are securities in which all public officers and public bodies of the state and its political subdivisions, all insurance companies, trust companies, banking associations, investment companies, executors, administrators, trustees, and other fiduciaries may properly and legally invest funds, including capital in their control or belonging to them. These obligations may be deposited with a state or municipal officer of an agency or political subdivision of the state for a purpose for which the deposit of bonds, notes, or obligations of the state is authorized by law.

Sec. 41.41.390. Refunding bonds. (a) The authority may provide for the issuance of refunding bonds for the purpose of refunding an obligation then outstanding that has been issued under the provisions of this chapter, including the payment of redemption premium on them and interest accrued or to accrue to the date of redemption of the obligations. The issuance of the bonds, the maturities and other details of them, the rights of the holders of them, and the rights, duties, and obligations of the authority in respect of them are governed by the provisions of this chapter that relate to the issuance of obligations insofar as those provisions may be appropriate.

(b) Refunding bonds may be sold or exchanged for outstanding bonds issued under this chapter, and, if sold, the proceeds may be applied, subject to appropriation and in addition to another authorized purpose, to the purchase, redemption, or payment of the outstanding obligations. Pending the application of the proceeds of refunding bonds, with any other available funds, to the payment of the principal, accrued interest, and redemption premium on the obligations being refunded, and, if so provided or permitted in the resolution authorizing the issuance of the refunding bonds or in the trust agreement securing them, to the payment of any interest on the refunding bonds and expenses in connection with the refunding, the proceeds may be invested in direct obligations of, or obligations the principal of and the interest on which are

Article 6. General Provisions.

Sec. 41.41.900. Tax exemption. All obligations issued under this chapter are declared to be issued by a body corporate and public of the state and for an essential public and governmental purpose, and the obligations, and the interest and income on and from the obligations, and all fees, charges, funds, revenues, income, and other money pledged or available to pay or secure the payment of the obligations, or interest on the obligations, are exempt from state taxation except for transfer, inheritance, and estate taxes.

Sec. 41.41.990. Definitions. In this chapter,

(1)"authority" means the Alaska Natural Gas Development Authority;

(2)"board" means the board of directors of the Alaska Natural Gas Development Authority;

(3)"project" means the gas transmission pipeline, together with all related property and facilities, to extend from the Prudhoe Bay area on the North Slope of Alaska to tidewater at a point on Prince William Sound and the spur line from Glennallen to the Southcentral gas distribution grid, and includes planning, design, and construction of the pipeline and facilities as described in AS 41.41.010(a)(1) - (5).

* **Sec. 3.** AS 39.25.110(11) is amended by adding a new subparagraph to read:

(G) Alaska Natural Gas Development Authority;

* **Sec. 4.** AS 39.50.200(b) is amended by adding a new paragraph to read:

(57) the board of directors and chief executive officer of the Alaska Natural Gas Development Authority (AS 41.41.020 .

* **Sec. 5.** The uncodified law of the State of Alaska is amended by adding a new section to read:

DEVELOPMENT OF PROJECT PLAN. Not later than one year after the first meeting of the board of directors of the Alaska Natural Gas Development Authority, the board shall produce a development plan. The development plan must include

(1) estimates of construction costs and timelines;

(2) gas procurement prices;

(3) use of the state's royalty gas;

(4) estimates of revenue to the general fund and the Alaska permanent fund;

(5) a revenue sharing plan with municipal governments;

Department of Revenue testimony

Larry Persily, Deputy Commissioner
Before the Joint Legislative Committee on Natural Gas Pipelines
Nov. 7, 2001 in Kenai

Pursuant to your instructions in Senate Bill 158, the Department of Revenue and its consultants have been working for the past few months compiling a report for the legislature on the merits of state or public ownership and/or financing of a natural gas project. In addition to consulting with experts on debt financing and project financing, we've interviewed more than 30 individuals plus representatives from 10 companies in the oil and gas industry – not just the producers but the large and not-so-large players in the pipeline business. Our list of interviews also has included many Alaskans involved in banking, the oil and gas industry, legislators and business leaders.

Certainly, the Alaskans we interviewed all would like to see a gasline built to create jobs in Alaska, to generate tax revenues to pay for public services, and to promote the economic activity that would come with such a large construction project. Obviously, we don't need a study to tell us that. What we're looking at are the risks to the state – and the benefits – of becoming a member of any partnership that builds and operates the line. And we're looking at how — and what would happen — if the state wanted to raise the hundreds of millions or billions of dollars needed to buy into the project.

Here are some of the questions we're trying to answer:

- What if we sign on as a partner and there are serious cost overruns during construction? What if the partners are all required to pay in more money to cover those overruns? Will the state be able to come up with the money? It's always possible that federal regulators — FERC — may not allow the pipeline owners to recover 100% of the cost of any overruns. Is it smart to commit to some possible unknown expense in the future, given that the state already is running short of cash? Even worse, what if some unforeseen event blocks or stalls completion of the line? Granted, the risk is small judged by the odds of it happening, but the risk does exist. We need to consider that the Constitutional Budget Reserve Fund is at $2.8 billion and falling. We're looking at around $2.5 billion by the end of the fiscal year next June 30, and below $2 billion one year later. The Permanent Fund Earnings Reserve Account, which had $6.1 billion just a couple of years ago, is at $2.7 billion this week after a bad year in stocks while still continuing to pay full dividends.

- After the pipeline is built and the gas is flowing, there are still price risks to the owners of the line. This is the cost of getting the gas to market, and whether the market will be willing to pay that cost in full year after year. Whereas the cost of moving North Slope oil to market is about 25% of the sales price at the

refinery, the cost of moving gas to Chicago is closer to 80%. There just isn't that much margin left after paying the transportation tariff on the pipeline. A small swing in the market price for gas could mean a losing year for whomever is carrying the risk. That's the central issue in all this – who takes the price risk that, in any given year, the price for gas in Chicago will not be sufficient to cover the tariff of moving it from Alaska to the Midwest, plus the cost of production, taxes, and a profit? Generally, the gas producers take this risk, but in the case of the Alaska project, because of its size, we expect there may be some sharing of the risk between the producers and pipeline owners. Certainly, if the producers agree to take all the price risk, pipeline ownership could be a good investment for the state, consistent with Permanent Fund earnings on a risk-adjusted basis.

As I said, we expect that the three North Slope producers are hesitant to take all the risk – the risk of construction cost overruns if they build the pipeline and the larger risk that some years the market will not pay enough to cover the $2+ pipeline tariff plus other costs. Even if you lose just a dime on every thousand cubic of gas in a 4 billion cubic foot per day line, that loss could total $400,000 a day, or almost $150 million over a full year.

Of course, the pipeline companies would be happy to build the line if the producers agree to take all the risk – signing "ship-or-pay contracts," committing to pay the pipeline companies a fixed tariff regardless of the market price.

The decision whether to build the gasline, and who will build it, will come down to a deal over who is willing to share how much of the price risk.

- Also thinking about risk, does it make sense for the state, which is already heavily dependent on oil revenues, to take a large investment in gas? Should we instead diversify from the oil and gas sector in generating state revenues?

  It's one thing for a corporation to take a risk that could mean no dividends to shareholders if it goes sour one year. It's another thing for a state to take a risk with providing essential public services. Remember, we expect the Budget Reserve to hit empty in the second half of 2005, and the Permanent Fund earnings reserve has taken a major hit in the stock market.

- Would the state be better off letting someone else take all the risk, and we then would do what we do best – and that is tax the profits?

- Putting aside the risk issues, we next will have to answer the questions: What can the state bring to table as a partner in the project? Would state government involvement actually slow down a commercial operation? Does the state gain anything worthwhile for taking a share of the risk?

In our research and analysis, and our interviews with producers and pipeline companies, here is what we ve learned:

- Project sponsors — be they gas producers or pipeline companies — already have access to all the capital they need if they decide to build the project. State involvement just isn't needed for financing.

- State investment doesn't do anything to lessen the financial risks for the other partners, so they don't gain anything from having us as a partner. Project risk is mostly dictated by the marketplace, and the state has no control over that.

- Alaska already has a significant future income risk in the energy sector. Why would people want to compound the situation by making a large, discretionary investment in energy? An executive said by investing in a project that will not be cash-flow positive for a number of years, the state is depriving its citizens of the present-income value of its limited investment capital.

- Although some may believe the state would gain a "seat at the table" as a partner in the pipeline, we wouldn't really gain any more information than we would be able to get on our own — especially through the Federal Energy Regulatory Commission, which would regulate the pipeline tariff, and through the state's own regulatory agencies. We couldn't use confidential, proprietary information from the table against companies in tax cases, and we couldn't use the information to out maneuver our partners in gas marketing opportunities.

- As a partner, the state might face the political temptation to meddle in the business operation.

  As one pipeline company said, quite bluntly, the state would need to recognize that board discussions are open, frank, and confidential. Decisions would need to be made for the best interest of the project, not necessarily the state. Decisions of and debate of the joint venture board cannot be shared publicly. This might not be compatible with state ownership.

  Another executive explained that a seat at the table is a fine political concept, but the state's participation likely will hurt the viability of the project. The decision-making process of the state on the joint venture governing board likely will be influenced by political, not business, concerns and will be slow. Management of any joint venture is, by its very nature, very difficult. A governmental entity will only increase the complexity because governments are not accustomed to making quick, unemotional decisions.

- The state already can regulate much of the operations of the line through right-of-way permits and regulatory oversight functions.

- Being a partner could put the state into a conflict of interest situation. What would be more important to the state – running the line at maximum profit, or following new, perhaps costly environmental or safety or regulatory rules?

- And, a final, should the state own a piece of a project in a foreign country?

If the state decided to go ahead and take the risk as a partner in the project, where would we get our share of the cash to buy into the gasline?

Under existing federal law, the state or any other public entity could not issue tax-exempt debt except for a very small portion of the project. Only those facilities available for public use, such as a dock or highway or distribution hub available for all users, would qualify under federal law for tax-exempt financing. Everything else would be financed with taxable bonds.

Federal law does allow the state to issue a limited amount of tax-exempt debt for private-activity uses, but that currently is set at $187.5 million a year, and is used in full by AHFC, AIDEA, the student loan corporation and others.

Congress could change the tax laws as it has for other projects, but without a change in federal law, tax-free bonds do not appear to be possible for raising the state's share of buying into the project. The same restriction likely would apply to a port authority or other, similar public corporation or agency.

Another issue is that we don't believe the state could issue general obligation bonds for this project. State ownership in the gasline likely would fail to meet the required standard of a capital improvement or public improvement.

But if we could issue GO bonds for our investment in the pipeline — assuming the state wants to preserve its existing AA credit rating — a conservative estimate of our debt capacity would allow us to commit no more than 5% to 8% of our general fund revenue stream to debt payments. That's been the state's target for years, and it has served us well in maintaining a good credit agency. At a limit of 8% of general fund revenue, the state could issue somewhere around $200 million to $300 million in 10- or 15-year bonds over the next six years. Those numbers are based on the state's current fiscal situation, meaning the budget gap. If the state were to adopt new revenue sources, be it taxes or using some Permanent Fund earnings, we would have the capacity to issue significantly more debt by the end of the decade.

But also keep in mind that that any estimate of Alaska's bonding capacity today does not yet account for bonds under consideration, such as the new DEC seafood lab, deferred maintenance on public buildings, schools and harbors. The gasline would have to compete with all those other needs for GO debt.

The state or another public entity could issue revenue bonds, pledging the future revenue from the gasline to pay back the debt. But there are some problems here, too.

- One, if the state backed the revenue bonds with a moral obligation, we'd have to use tax money or Permanent Fund earnings if gasline revenues were insufficient in any given year to cover debt service. If we sold the bolds based solely on the gasline revenue — with no other assets or income at risk — we'd probably have to pay much higher interest rates to borrow that money. Much higher than what the producers or pipeline companies would have to pay on their own debt.

- Two, the state would be at risk if the gas flow or revenue stream were disrupted. We would no longer have the revenue to pay back the debt.

- Three, even with pledging future gasline revenues, the state still couldn't match the excellent credit rating and lower interest rates that companies such as Exxon and BP could get. For example, looking at taxable bonds, the difference between Exxon's AAA rating and the state's AA rating — if we could maintain that grade — would be $20 million in interest payments in the first year on a $10 billion debt.

- Four, we don't believe 100% project financing is feasible for this project for any governmental entity. Regardless of what the port authority is told by its lawyers and financial advisers, our research indicates it is close to impossible to obtain 100% debt financing for a project operated by a government entity with no experience in such projects and with just a single source of revenue to repay the debt. The answer might be different if the producers were willing to absolutely guarantee a high enough price for a high enough volume of gas for a long enough period of time to pay back the debt, but if they're going to take all the risk why would they want to work through the state or a port authority when they could issue their own debt at a lower cost?

One other comment I want to make is that back in 1978 the pipeline companies were encouraging state investment in the project. Federal law back then prohibited oil and gas producers from owning a pipeline, so that source of funding was not available. The project was estimated to cost $20 billion or more, and that was more than the pipeline companies could afford. Simply put, they needed the state. But the law has changed and the producers can own the line. And the financial strength of many of the companies involved has grown. And the cost is much lower. No one really needs us any more.

These are our preliminary findings and thoughts to date, and could change as we continue with our work. Our final report will be delivered in January, and we would be happy to give you an update next month at your convenience.

ALASKA HIGHWAY NATURAL GAS POLICY COUNCIL



REPORT TO THE GOVERNOR

EXECUTIVE SUMMARY

NOVEMBER 30, 2001

Efforts to Develop North Slope Gas Have a Long History

For almost 30 years – since oil was first discovered on the North Slope – oil and gas companies and Alaskans have been working on ways to market large gas reserves on the slope.

1970 In 1970, the Arctic Gas consortium, mainly U.S. pipeline companies and large gas utilities, proposed a land pipeline east from Prudhoe Bay, crossing what is now the coastal plain of the Arctic National Wildlife Refuge, to Canada's Mackenzie Delta. The pipeline would then run south along the Mackenzie River Valley to connect to the existing U.S. and Canadian pipeline grid.

1974 In 1974, El Paso Natural Gas proposed an "all-Alaska" pipeline across the state to a proposed liquefied natural gas (LNG) plant in southern Alaska. El Paso wanted to ship LNG to the U.S. West Coast.

1976 In 1976, Congress passed the Alaska Natural Gas Transportation Act (ANGTA), designating a special process for a Presidential Finding to select a pipeline route, and for expedited permitting.

1977 In 1977 the Canadian government decided against the Arctic Gas plan, citing unsettled Native land claims along the Mackenzie River route of the pipeline as the main reason.

A second consortium formed to build a pipeline on an alternate route parallel to the oil pipeline to the Fairbanks area, then southeast along the Alaska Highway into B.C. and Alberta. This group included Canadian as well as U.S. companies.

In 1977 President Jimmy Carter approved the Alaska Highway route as the approved corridor for a North Slope gas pipeline. Canada followed suit with similar legislation, and the "Alaska Highway" route was given official blessing by both the U.S. and Canadian governments. It was designated the Alaska Natural Gas Transportation System (ANGTS).

Through the late 1970s and early 1980s, partners in the ANGTS group spent hundreds of millions of dollars on engineering, environmental work and permits.

1982 In 1982, plans to build the ANGTS were suspended when the project partners were unable to agree on a financing plan, given the high costs of the project.

Concerned that Alaska North Slope gas would be "stranded," two former Alaska governors, Walter Hickel and William Egan, and several Alaska businessmen formed Yukon Pacific Corp. to resurrect El Paso's idea for a pipeline across Alaska to an LNG plant. Unlike El Paso, Hickel envisioned shipping the LNG to Asia. For almost a decade, Hickel and Yukon Pacific were the only promoters of an Alaska gas project.

1992 In 1992, North Slope producers decided to take a new look at a trans-Alaska gas pipeline and an LNG export project. A joint study team was formed by the major gas owners, ARCO, BP and Exxon.

1995 In 1995, after tens of millions of dollars were expended in new studies, the joint study team was disbanded. The companies pursued gas marketing individually. ARCO continued to investigate LNG exports, while Exxon concentrated on its new gas-to-liquids technology as a possible way to market North Slope gas.

1998 In 1998, the Alaska Legislature passed the Stranded Gas Act, establishing a framework for negotiation of special fiscal terms for an LNG export project.

1999 In 1999, ARCO formed a proposed "sponsor group" of itself, Phillips Petroleum, Foothills Pipelines, Marubeni Corp. and Yukon Pacific. Yukon Pacific eventually withdrew from the group and BP joined it. After the BP-ARCO merger, Phillips assumed ARCO's share of the project. This group is still at work, focusing now on finding synergies between an LNG project and the proposed all-land pipeline to the lower 48.

2000 In 2000, the three North Slope producers, BP, ExxonMobil and Phillips (heir to ARCO Alaska), formed a joint group to study pipeline routes to the lower 48. Their work, expected to cost about $100 million, is still underway.

2001 In January 2001, Governor Knowles formed the Alaska Highway Natural Gas Policy Council. He directed the 28-member Council to engage Alaskans and develop recommendations for promoting a natural gas pipeline project that maximizes benefits to all Alaskans.

In 2001, Foothills Pipelines owned by TransCanada and Westcoast Energy and six former members of the ANGTS consortium, subsidiaries of Duke Energy, El Paso, Enron, PG&E Corp., Sempra Energy and Williams Energy, announced they would reform the consortium and present a plan for a pipeline to the North Slope producers.

In 2001, Congress is again revisiting possible legislative changes that would speed construction of an Alaska gas pipeline. North Slope producers have proposed legislation that would set up a new procedure for permitting a gas pipeline. The State of Alaska has proposed modifications of the existing Alaska Natural Gas Transportation Act, which endorses a "southern" or Alaska Highway pipeline route.

A Letter from Governor Knowles

November 30, 2001



Dear Alaskan,

The time is right to bring Alaska's North Slope gas to market. American consumers are demanding affordable, environmentally friendly energy and our state has the resources to deliver. A gasline project will provide good jobs for Alaskans, affordable energy for our communities and revenues to pay for vital services.

That is why last January 1 formed the Alaska Highway Natural Gas Policy Council and asked 28 distinguished Alaskans to examine how the state can promote a gasline project that maximizes benefits to Alaska. I asked the Council to go out and talk to project proponents, natural gas experts, and – most importantly – Alaskans. I encouraged them to ask the tough questions.

The Policy Council's work exceeded expectation. The Council held comprehensive workshops to examine the issues surrounding gasline development. They heard from Alaskans during public hearings held in Fairbanks, Kenai, Anchorage, Tok, Barrow, Juneau and Valdez. Finally the members worked through a subcommittee process that culminated in a series of thorough and useful recommendations.

I am proud to receive this report. The Council's recommendations will be extremely helpful to me and my Administration as we continue to advocate for an Alaska Highway natural gas pipeline.

I thank the Council members for their exceptional hard work and dedication. This report will no doubt serve as a guide to Alaskans as we work together to make a highway gasline project a reality.

Sincerely,

Tony Knowles
Governor

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Note to readers:
This is the Executive Summary of the Alaska Highway Natural Gas Policy Council Report to the Governor. For more detailed information, please see the Council's complete report. To obtain a copy of the report, please call (907) 269-7450 or visit www.gov.state.ak.us/gascouncil.

Introduction: A Report to Alaskans

Through the spring, summer and fall of 2001 several hundred Alaskans met in community meetings around the state to advise our state's leaders on important issues involving natural gas policy and the construction of a natural gas pipeline from the North Slope to the lower 48.

The advice and information contributed in these meetings were distilled by 28 Alaskans – business, labor and local government leaders, legislators and state officials – appointed by the governor to the Alaska Highway Natural Gas Policy Council. The results of those efforts are the recommendations in this report.

Based on the advice received during these meetings from Alaskans as well as industry, expert consultants and state officials, the Council believes:

• **Arctic gas is critical to the nation's energy and economic security.** Despite the extreme volatility in natural gas prices, long-term market trends continue to point to a strengthening in natural gas prices along with future shortages of domestic gas supplies and deliverability. Our nation has a strategic energy security need to develop North American energy instead of relying on increased imports of oil and gas from foreign sources.

• **A southern pipeline route through Alaska's Interior, the "Alaska Highway" route, will best serve the nation's and Alaska's interests.** The Council believes the apparent cost advantages of an alternative northern "offshore" pipeline route are illusory because of construction challenges and probable environmental permitting delays posed by the difficult offshore Arctic ice-pack environment.

• **The Council believes a pipeline could be economic and attractive to certain investors, assuming a long-term price of $3 per thousand cubic feet (mcf) flat real prices.** The Council believes there is an urgency to make the project move forward so that the projected long-term gap in North American supply is met by North American natural gas rather than supply imported from uncertain sources overseas.

Alaska Gas is Critical to the Nation's Energy and Economic Security

A paramount consideration is the importance to the security of the United States of natural gas delivered through a secure, buried pipeline from Alaska and Arctic Canada. Our nation is too dependent on oil imported from unstable and even unfriendly foreign nations. Increasingly, natural gas is being looked to as a substitute for oil.

Gas is also clean-burning, an important consideration in meeting the nation's goals for clean air.

Our nation faces a long-term shortage of natural gas, all experts agree. The regions which now produce gas cannot meet the projected long-term growth, and it is unlikely that other areas being explored, such as the U.S. Gulf of Mexico or Canada's eastern offshore provinces or western provinces, will meet all of those needs. Natural gas from many of the other sources in North America tends to have a faster rate of decline, while North Slope gas can be produced at constant production rates for a longer period of time, a distinct advantage for consumers who want surety of long-term supply. Arctic gas from Alaska and Canada can meet those needs.

Despite the extreme volatility of lower 48 gas prices over the last 18 months, most experts agree that by the latter years of this decade gas prices over the long term will be set by the cost of imported liquefied natural gas (LNG). This is expected to be between $3 and $3.50 per thousand cubic feet (mcf). It is this and not the current price gyrations that will determine the viability of the pipeline project.

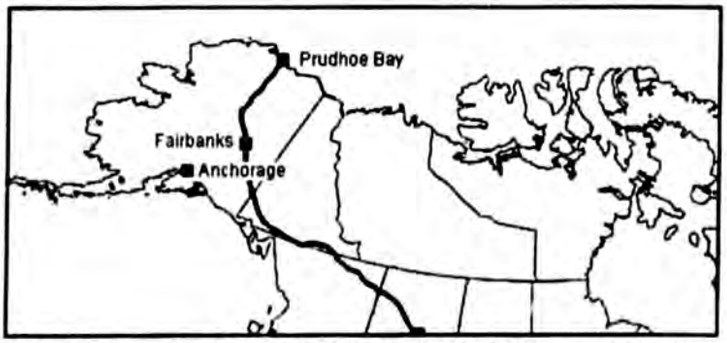
Alaska gas is also economically important to the nation. Four billion cubic feet of gas, and potentially 6 billion cubic feet, can be delivered daily through an Alaska gas pipeline at an affordable price that will boost the economies of North America. Four billion cubic feet delivered daily will represent over 5 percent of the nation's estimated gas demand of 75 billion cubic feet per day at the end of this decade, a supply large enough to dampen or prevent future price spikes. Lower 48 consumers will benefit from a gasline delivering Arctic gas.



The Council toured the Phillips Alaska LNG Plant in May.

During construction, the pipeline will provide considerable jobs in construction, manufacturing and transportation to the nation's workforce, creating a payroll in excess of a billion dollars a year. The cumulative, long-term effect of bringing North Slope gas to market is estimated at 160,000 American jobs and a several billion dollar addition to our gross domestic product. At a time when our nation faces economic uncertainties, this project is of vital national importance.

A Southern Pipeline Route Will Avoid Delays and Speed Delivery of Alaska Gas



An Alaska Highway gas pipeline would travel from Prudhoe Bay to Fairbanks, and then along the Alaska Highway to Alberta to connect with the North American pipeline grid.

It is the Council's belief that a "southern," all-land pipeline route through Alaska's Interior and following the existing Alaska Highway will deliver gas earlier and at less cost to consumers than a "northern," offshore pipeline. A northern route would rely on construction technologies never attempted, at that scale, in a difficult Arctic offshore environment. Because of these challenges, the Council believes there will be no cost savings for the northern route. Summer icepack movements will challenge summer construction, and ice gouging of the ocean floor and ice ridges in winter months pose a very difficult year-round operating environment. In addition, several Alaska Native groups and environmental organizations have voiced strong opposition to the northern route but have expressed support in working with the state and industry on southern route permitting. There will be a lengthy delay in permitting – if permits are ever obtained – for a northern offshore route under the Beaufort Sea ice.

A Gas Pipeline Will Strengthen and Diversify the State's Economy

As for its importance to Alaska, we find that this project, when constructed, will strengthen and diversify our economy by creating a new natural gas exploration and production industry on the North Slope, which will help extend the life of our existing oil fields. This will result in new revenues to the state, shrinking a projected future fiscal gap.

A gas pipeline will encourage the manufacturing in Alaska of products made from gas, similar to the way Cook Inlet gas led to local manufacturing of products such as fertilizer.

While the Council believes North Slope gas may someday be exported to Asia and the U.S. West Coast through a liquefied natural gas plant in southern Alaska, an all-land pipeline to the lower 48 appears more economically feasible as an initial project.

A gas pipeline could also bring clean, affordable energy to many Alaskan communities now dependent on fuel oil. Gas could also be brought to southern Alaska to meet future demands for gas in the Cook Inlet area, potentially extending the life of the industrial plants and making a larger LNG export plant possible.

Unless new significant gas reserves are developed, a shortfall in natural gas deliverability for peak winter demand is predicted for Southcentral Alaska by 2006-08. This shortfall in gas supply in Anchorage and the Cook Inlet area can be offset only by more expensive sources of natural gas or alternative fuels. In future years, the deliverability shortage will be more pronounced. North Slope gas can provide a long-term stable supply source to the main population center of Alaska.

Although there will be fewer construction jobs than the trans-Alaska oil pipeline in the 1970s, many Alaskans will find good employment. The project will stimulate training which will strengthen the skills of our workforce.


The Governor greets Barrow residents before the Council's hearing at the North Slope Borough Assembly Chambers.

A Southern, "Highway" Pipeline Route is Needed for Many of These Benefits

For many of these benefits to be realized, however, the pipeline will have to be built along a route through Interior Alaska and to the lower 48 through the Yukon Territory, the so-called "Alaska Highway" route. In our meetings around Alaska, we found Alaskans united in support of a southern route, with no public support from Alaskan communities for an alternative offshore, or northern, route that is also being studied by the North Slope producers.

An important consideration is how ownership of a gas pipeline is structured. First, the North Slope producers may wish to build, and own, the pipeline. Secondly, a consortium of pipeline, or gas transmission, companies could build and own the pipeline. In this case, producers would sign contracts with the pipeline companies for transportation of gas. A third option is a combination of one or more producers and pipeline companies in a consortium. A fourth possibility is for the Alaskan segment of the pipeline to be financed and owned by a vehicle such as a public authority. This authority would finance its share of a pipeline through access to capital markets much as pipeline companies would do. This vehicle could bring possible tax advantages, such as exemption from payment of State and Federal income tax.

There are advantages with each form of ownership. An advantage of producing companies doing the project is that they would be able to finance part of the project themselves. This could lower financing costs. Independent pipeline companies would look more to capital markets, but an advantage for the state is that these companies, which are in the transportation business, are typically more open to expanding the system to ship gas discovered in the future. (Producing companies traditionally build only enough capacity to meet their own requirements.) Additionally, pipelines in the lower 48 owned by pipeline companies sometimes ship gas at lower costs than pipelines owned by producers. A consortium that combines producing and pipeline companies might have the advantages of both forms of ownership.

The Council believes ownership of the Alaskan segment of the pipeline and construction of in-state gas distribution infrastructure by a public authority is an interesting idea that merits further study, as long as financing is drawn from private capital markets. There are some very significant challenges involved but the tax advantages mentioned earlier might make this vehicle an option in the event that the producers or gas transmission companies elect not to proceed with the project. The public authority vehicle may be applicable for smaller parts of the in-state gas infrastructure, such as spur lines off the main pipeline. This could be one way energy costs for Alaska consumers could be lowered.



The Gas Policy Council tours the BP Gas-to-Liquids test facility construction site in Nikiski:
(l-r, back row): Jack Roderick, Debra Ceffalio, Pat Pourchot, Rep. Mike Chenault, Tom Boedeker, Charles Coulson, John Ringstad, Angela Sorrentina, Barry Babyak, Jim Sampson, Tom Maloney
(l-r, front row): Ken Freeman, Frank Brown, Michael Hurley, George Findling, Grace Schaible, Steve Fortune, Shane O'Leary

Important Policy Issues Considered by the Council

Following seven Council hearings around the state and meetings of the five committees, 61 recommendations for State policy were developed, with supporting conclusions. They were adopted unanimously by the Alaska Highway Natural Gas Policy Council.

Some highlights among these recommendations include:

• The State should not invest directly in a gas pipeline project unless there is clear evidence of economic benefits to Alaska that cannot be achieved through other regulatory or political mechanisms. However, a public financing vehicle, such as a public authority, could play an important role in financing segments of the pipeline because of possible tax exemptions.

• The State's option to take its royalty gas in-kind must be retained. Sales of royalty gas to companies other than producers will foster competition, leading to greater values and more benefits to residents.

• Alaska must have a role in the review and approval of tariffs (transportation costs) and other charges affecting transportation of gas from the North Slope to Alaska communities. The Council recommends either Congress give the state Regulatory Commission of Alaska authority over intra-state gas issues similar to the State's authority over intra-state shipment of crude oil through the TAPS oil pipeline, or a joint board be created between the state's regulatory commission and the Federal Energy Regulatory Commission.

• The State should complete a thorough study of various approaches to in-state natural gas pricing of in-kind royalty gas.

• Several policy clarifications are necessary to enhance the value of the State's one-eighth royalty share of gas production, including basing value on actual market transactions rather than a formula (at least initially), and including sales of natural gas liquids in reported values.

• The southern, or Alaska Highway route is the environmentally preferred route.

• As allowed by North Slope oil and gas leases and existing statutes, the State should keep some of its royalty gas "in-value" by allowing the producers to market the gas and pay the State royalty payments. To increase natural gas marketing competition, however, the State should keep some of its royalty share of gas "in-kind" and allow third parties such as natural gas trading firms to market the gas to consumers.

• The experience with the Trans-Alaska Pipeline System must be drawn on. State and federal agencies must be adequately funded to perform the necessary oversight of pipeline construction and operation. Processes for effective public involvement need to be implemented.

• Training for Alaskans should be encouraged, and funded if necessary, to realize an important goal of using the opportunity of a large construction project to strengthen the skills of Alaskan workers.

• An important conclusion by the Council is that a connection for gas offtake on a high-pressure pipeline will be costly. Taps should be at strategic locations, or "hubs", along the pipeline, from which natural gas and natural gas liquids such as propane and butane could be supplied for local and regional distribution, and electricity could be generated and distributed. To meet clean energy needs in Fairbanks, Anchorage and other communities, spur gas pipelines could be constructed.

• Leases signed by the producers on the North Slope legally stipulate an implied covenant to market gas within a "reasonable time" and at a "reasonable price." It is assumed that 25 years since the start of production at Prudhoe Bay meets the reasonable time stipulation. Producers will thus have to sell their gas to pipeline companies or third parties if a "reasonable price" offer is made, and assuming other bid terms are acceptable.

• The State should ensure a southern or Alaska Highway route is mandated in any proposed federal gasline legislation and that Alaska's needs are appropriately addressed in the legislation. The Council supports modifications to modernize the Alaska National Gas Transportation Act and believes such modifications would be beneficial to an Alaska gasline project.



Carl Marrs addresses the audience at the Council's Barrow hearing.

ABOUT NATURAL GAS:

What is natural gas?

Natural gas, crude oil and gasoline are hydrocarbons, a mixture of molecules composed of hydrogen and carbon atoms. The simplest hydrocarbon has one carbon atom with four hydrogen atoms stuck to it, CH4 methane, the fuel Cook Inlet residents use. Methane, ethane, propane, butane and pentane, which are typically in natural gas as it is produced, have relatively simpler hydrocarbon molecules compared to crude oil or gasoline, which are a mixture of bigger and more complicated hydrogen-carbon molecules.

What are natural gas liquids?

What we usually refer to as natural gas is predominantly methane, which is used mostly as fuel, but can also be used to make fertilizer and other products when the molecules are separated or "cracked." Methane is called "dry" gas, because at normal temperature and pressure, it remains in a vapor form. Ethane, propane, butane and pentane are referred to as natural gas liquids (NGLs) because they are often in liquid form at higher pressure or lower temperature. They are typically separated from the methane and sold separately. Wet gas is more valuable than dry gas because it contains more Btu value per given volume.

What is liquefied natural gas?

Liquefied natural gas, or LNG, is dry natural gas (mostly methane) that is chilled to extremely low temperatures so that it becomes a liquid that can be shipped in a tank, on a ship or even by truck or train. An LNG plant near Kenai now ships liquefied gas from Cook Inlet area fields to customers in Japan.

Natural Gas Policy Council Hearings: Alaskans Speak Out

In addition to meeting with industry experts and project proponents, the members of the Alaska Highway Natural Gas Policy Council traveled to seven communities across the state to talk to Alaskans about the proposed gasline project.

Fairbanks Residents Advocate for Local Access to Gas

The public hearing process began in April with a meeting held at the Fairbanks Chena River Convention Center. Over 200 Interior residents attended, including city officials, labor and business representatives and native leaders.

A common theme throughout the evening's testimony was the need to bring natural gas to Fairbanks for residential and commercial use. Many residents also expressed enthusiasm for the pipeline's potential to be an enormous economic boost to the region.

Steve Ginnis, president of the Tanana Chiefs Conference, spoke about the importance of native village involvement. Ginnis told the Council that because the highway route will cross Native lands, it is important that Native villages be represented on the planning committees. The villages also need access to the gas to reduce energy costs and improve living conditions.

Several business leaders also testified. "We do plan on building the next pipeline," said Bert Bell, President of the Association of General Contractors of Alaska. But Bell reminded Council members that the pipeline's labor needs must be known soon so training programs for Alaskans can begin.

Peninsula Residents Promote In-state Gas Use

In May, the Gas Policy Council saw the industrial uses of natural gas firsthand when they traveled to Kenai and toured the BP Gas-to-Liquids test facility, the Agrium fertilizer plant and the Phillips LNG plant. After the tours, the Council held a public meeting to hear from Peninsula residents. Kenai residents expressed their strong desire to bring North Slope natural gas to the Cook Inlet region to fuel existing industry and create new economic opportunities.

Speaking on behalf of the Cook Inlet Pipeline Terminus Group, Mike Navarre told the Council "seventy percent of the state's population lives along the corridor a pipeline would follow to Cook Inlet. It's the economic base of the state. An economy needs room to grow, and there is ample space for development in Nikiski, the Mat-Su area and along the Railbelt to Fairbanks," Navarre said.

John Williams, Kenai city mayor, spoke about the importance of using Alaska gas in-state. He urged the Council to propose changes in state law that would require as much gas as possible be processed in Alaska. BP's gas-to-liquids test facility in Kenai demonstrates the potential for gas to be used as a feedstock, Williams said.



Kenai Mayor John Williams testifies at a Council hearing.

Anchorage Residents Highlight Need for Gas to Cook Inlet

While the testimony at the Anchorage hearing was broad and varied, one theme emerged. Anchorage businesses and residents want to ensure that Cook Inlet has access to natural gas.

Tony Izzo, president and CEO of Enstar Natural Gas, told the Council that Anchorage has "one of the best gas utilities in the country, with new high-tech systems, 400 miles of pipelines and 2,400 miles of distribution lines." While Enstar has contracts pending to meet all its supply needs to 2006 and some of its needs to 2017, beyond that there are long-term supply concerns.

Steve Cleary, speaking on behalf of the Alaska Public Interest Research Group, said his members' concerns were those of consumers and utilities in the region. "In the next decade our members will need a reliable source of gas, and we think it must be North Slope gas."

Tok Residents Contemplate Impacts of Gasline

At a June hearing, residents of Tok expressed support for a natural gas pipeline route through their community to Canada, though they were leery of the possible impacts to their small community.

Most residents supported local access to the gas pipeline that could run through their community, but some pointed out that there will be costs associated with natural gas access, such as the cost of tapping the pipeline and building local distribution lines to several hundred widely scattered homes in the Tok community. Tok resident John Portscheller worried that the region could loose its rural character if the pipeline leads to development of local infrastructure and stimulates formation of a regional municipal government.

There were also comments about local hire for the project. One resident stressed the importance of hiring people from the local communities, not just residents of the state.

Overwhelming Opposition to the Northern Route Heard in Barrow

In July, the Council traveled to Barrow to listen to residents of the North Slope. Local government and village leaders told the Council emphatically that they will support a natural gas pipeline, only if it follows a southern route.

Speaking on behalf of the Alaska Eskimo Whaling Commission, Charlie Neakok, vice president of the Barrow Whaling Captain's Association said: "The Alaska Eskimo Whaling Commission is prepared to work cooperatively with the gas producers" if they bring the pipeline down the highway. "However, the AEWC and the whaling captains of all 10 whaling villages will oppose, absolutely, any attempt to build a gas pipeline through our Beaufort Sea."

Marie Carroll Adams of the Arctic Slope Native Association spoke about new research indicating subsistence foods help natives stay healthy. "We're finding out from recent studies that native people cannot live without subsistence food. It's killing us to eat non-native foods, and we need to protect those resources that keep us alive," Adams said.



In Barrow, the Council heard testimony about the importance of subsistence hunting in the Beaufort Sea. Here, former mayor Ben Nageak addresses the group.

Southeast Alaska Looks to Play a Role in Gasline Construction

At an August hearing in Juneau, residents of Southeast Alaska expressed enthusiasm for participating in the development of a gasline project.

Loren Gerhard, executive director of the Southeast Conference, told the Council that Southeast communities hope to play a role in gasline construction through logistics support. He pointed out that Haines, Skagway and Juneau are all well positioned to support gas pipeline construction.

Robert Venables, economic director of the City of Haines, told the Council that in addition to providing support services, Haines can be a site for manufacturing LNG for shipment to Southeast communities and possibly to Pacific export markets. There is a relatively short distance for a "spur" pipeline connection between Haines and the larger trunk pipeline.

Environmental advocates also attended the Juneau hearing to voice their opposition to a northern route. Sue Schrader of the Alaska Conservation Alliance, testified to her organization's strong opposition to the "over-the-top" route. "This route has the greatest potential for environmental impacts and will be vigorously opposed by the state and national environmental communities," Schrader said.

Valdez Residents Back Gasline to Prince William Sound

In August, the Council traveled to Valdez for its last public hearing and heard an in-depth presentation from the Alaska Gasline Port Authority outlining its proposal to use its tax-exempt status to develop natural gas. The Port Authority explained their economic model which shows a two-project "Y" line, a gasline to the lower 48 with a spur to an LNG facility in Valdez, to be viable.

Many Valdez residents spoke in favor of the Port Authority concept and in favor of bringing gas to Valdez. City manager Dave Dengel reminded the Council to look out for all Alaskans. He said that adding an LNG leg to the project will provide more benefits and opportunities to Alaskans.

Valdez Mayor Bert Cottle urged the Council to move forward with a gasline project that will bring inexpensive energy and economic opportunities to Alaskans.

Alaska Highway Natural Gas Policy Council Meetings

March 1
First full Council meeting,
Anchorage

March 23
Council workshop,
Anchorage

April 5
Council workshop,
Anchorage

April 18
Public hearing,
Fairbanks

May 17
Public hearing,
Kenai

May 24
Public hearing,
Anchorage

June 14
Public hearing,
Tok

July 19
Public hearing,
Barrow

August 2
Public hearing,
Juneau

August 23
Public hearing,
Valdez

September 7
Full Council meeting,
Anchorage

September 25
Full Council meeting,
Anchorage

October 31
Full Council meeting,
Anchorage

November 30
Report presented to Governor,
Anchorage

Alaska Hire/Buy/Build
Mike Navarre, Chair

Members
Jerry Hood, Rhonda Boyles, Jake Adams, Peg Tileston

Committee examined the following topics
- Use of the Alaska labor pool by contractors and subcontractors
- Use of Alaska businesses
- Training and readiness of Alaskans for jobs on a gas project
- Socio-economic impacts

Committee Meetings
- April 5, 2001, Anchorage
- August 2, 2001, Juneau
- September 25, 2001, Anchorage

Recommendation:
The committee believes Alaska residents and contractors should be employed on a gasline project when they are available and qualified. In turn, contractors should be encouraged to employ and train Alaska residents.

Recommendation:
The committee believes that Alaska hire language, similar to language from the BP/ARCO Merger "Charter Commitment," should be sought for the Alaska Highway natural gas pipeline and facilities. *(Note: see full report for charter language.)* It should be specifically stated that the quarterly report to the Department of Labor should include all contractors and subcontractors of the company or sponsor.

Recommendation:
The committee believes additional funding should be made available for vocational education training and should be coordinated with existing workforce training efforts now underway. Additionally, efforts should be increased to notify interested Alaskans of training opportunities available.

Recommendation:
The committee believes every effort should be made to ensure that needed gas production facilities are constructed at sites in Alaska.

Recommendation:
The committee recommends the state's Department of Community and Economic Development undertake a study to determine the socio-economic impacts of the gas pipeline along the Alaska Highway route. The Department has already begun implementation of this recommendation. *(See full report for a draft "scope of work" for this study.)* We recommend the scope of the study also be expanded to include impacts to local governments.

"We do plan on building the next pipeline. We need to compare pipeline construction needs to our current workforce needs."

Bert Bell, President, Association of General Contractors of Alaska, Fairbanks hearing

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Conclusions and Narrative:
The committee held several hearings regarding the constitutionality of local hire laws. The record in Alaska on local hire litigation is not encouraging. We believe it will be difficult to construct local hire legislation that will withstand challenges under the U.S. and Alaska Constitutions (equal protection and privileges and immunities clauses). Additionally, a successful Alaska hire provision is complicated by the national and international scope of the project. Voluntary, cooperative efforts with industry seem to hold the most promise and should be pursued.

The number of jobs will be significant and will exceed the available capacity of Alaskan workers. The committee heard testimony that there is already a crisis situation being created because of the aging workforce in the oil industry, without factoring in the effect of a large-scale project like the gasline. There are coordinated efforts already underway, by industry, unions, native and tribal organizations, the Denali Commission, the University of Alaska and state agencies to address the training of Alaskan workers, and those efforts will require additional funding. The Alaska Human Resources Investment Council has developed a white paper that details a comprehensive approach to workforce training.

In addition to assuring labor stability, a project labor agreement will facilitate the further ramping up of union training programs, bringing more Alaskans into apprenticeship and skill upgrade programs. An ancillary benefit of the PLA is the legality of geographic preference provisions of collective bargaining agreements.

"Alaska workers and businesses are better positioned today than ever before to take advantage of the economic opportunities that the construction and operation of a gas pipeline would create."

Allen Todd, General Counsel, Doyon Limited, Fairbanks hearing

Committee members heard testimony from rural residents along the pipeline route expressing interest in job opportunities. We believe that issue is best addressed through notification, to interested Alaskans, of available training and through registering of interested workers and their skills. Construction training in rural Alaska has increased to an unprecedented level in the past two years through initiatives such as the Alaska Works Partnership, various labor organization programs, and the Denali Training Fund and other efforts funded by the Denali Commission. Continued support of these initiatives, which have resulted in training and employment of hundreds of rural Alaskans in construction, is essential if residents of communities along the pipeline and in areas of the state suffering economic dislocation due to fisheries problems, are to share in the economic benefits of the project. The Department of Community and Economic Development is already working with Native nonprofits to create accurate job banks, focusing on rural areas and villages.

The committee also obtained information regarding module related jobs for gas treatment facilities and compressors. The opportunity is tremendous and construction of modules at Alaskan sites should be vigorously pursued. It is estimated that the module related jobs and opportunities will be bigger than the Alpine, Northstar, Badami and MIX projects combined.



Council Co-Chair Jim Sampson talks with construction workers at the BP Gas-to-Liquids test facility.



Mike Navarre discusses local hire issues at the Kenai public hearing.

TERMINOLOGY GUIDE:
Definitions of terms used in this section

BP/ARCO merger charter commitment: An agreement between the State of Alaska and British Petroleum regarding the State's nonobjection to BP's acquisition of Atlantic Richfield Corp. In the charter BP agreed to a variety of actions, including steps to train and employ Alaska workers and to build facilities in the state when possible.

Alaska Human Resources Investment Council: A private/public advisory council that sets policies and makes recommendations on training and vocational education. The council's policies guide allocation of approximately $80 million in federal training funds that come to Alaska annually.

Project Labor Agreement: A collective bargaining agreement between a developer or project owner and construction trade unions establishing the terms and conditions of employment on a specific project, and to which all contractors utilized by the owner will be signatory.

Alaska Works Partnership: A construction and maintenance training program conducted by Alaska building trades unions in partnership with rural communities and development entities.

Modules: Components of oil and gas (or minerals) processing facilities that are built at a construction site and moved to a remote oil field, or mine.

Alpine, Northstar, Badami, MIX projects: Large oil and gas module projects built in Alaska in recent years.

Access for In-State Gas Use and Future Opportunities
Ken Thompson, Chair

Members
Carl Marrs (vice chair), Rhonda Boyles, Al Adams, Brian Davies, Jim Jansen, Jerry Hood, Bob Penney, Jack Roderick, Lee Gorsuch, Jeff Feldman, George Ahmaogak, Bill Corbus

Committee examined the following topics
- Supply/demand for in-state natural gas
- Best practices valuation/netback pricing methodology to facilitate in-state gas use
- Ensuring fair and transparent access rules to natural gas for Alaskan customers
- Benefits of natural gas development to rural Alaska and to communities along the pipeline
- Future options over 50 years for projects utilizing: gas-to-liquids (GTL), liquefied natural gas (LNG), natural gas liquids (NGL), petrochemical feedstock, fertilizer, etc. for in-state use or for export to markets in Asia or the West Coast
- Promotion or attraction of investment for in-state distribution and value-added processing
- Assess costs and benefits of the State taking delivery of its royalty share vs. taking royalty payments; review other states' policies for best practices

Committee Meetings
- April 5, 2001, Anchorage
- May 24, 2001, Anchorage
- August 2, 2001, Juneau
- September 25, 2001, Anchorage
- October 16, 2001, Anchorage
- October 26, 2001, Anchorage

Goal #1: Assess current supply/demand for in-state natural gas use and assess potential demand for expansion of current use as well as conceptual new uses.

Recommendation:
A long-term clean energy plan and vision needs to be developed for Alaska, providing for substantially increased use of natural gas for residential and industrial use and for power generation.

Recommendation:
The State should take a long-term, broad and strategic view of its entire natural gas resources. This should include areas on the North Slope, including non-producing areas, Interior basins and in south Alaska. There is a significant potential gas resource base in Alaska much larger than the 35 tcf proven natural gas reserves in existing fields on the North Slope.

Recommendation:
The State of Alaska should undertake more intensive, updated geologic and geophysical studies of the natural gas potential of current non-producing areas, including Interior and Southcentral Alaska basins. This should include a more thorough assessment of basin geology and natural gas generation and migration utilizing the most modern technology tools, as well as a more thorough assessment of the producible methane gas potential from coal seams within Alaska. In recent years new tools, such as satellite imagery and soil sampling techniques, have been developed. Another gas resource that should be assessed is gas from gas hydrates on the North Slope and in Interior basins, which are very sizeable and could be developed in future decades as technology advances.

Recommendation:
The State should evaluate incentives and policies to spur the exploration by private companies for natural gas, to better delineate the natural gas resources not only on the North Slope but elsewhere throughout the state. Strategies and plans should be implemented to attract additional companies interested in natural gas exploration who now utilize new technologies, to the North Slope, Cook Inlet, the Interior basins and elsewhere in the state.

Recommendation:
A major gas pipeline should traverse Alaska if the State is to fully exploit its longer-term resource from all basins over 50-plus years and also to gain access to future multiple markets over the long-term. In addition such a pipeline could ensure long-term, reasonably priced supplies of energy to the Railbelt and other areas of the state, thereby encouraging economic development.

Recommendation:
The State should facilitate favorable policies and incentives to encourage development by the private sector of a broader natural gas infrastructure within the state that meets the long-term clean energy demand of Alaskans at reasonable market prices.

Goal #2: Assess how natural gas or natural gas products can meet the clean and economical energy needs of communities along the pipeline route and in rural Alaska.

Recommendation:
The State should sponsor a comprehensive economic and environmental study of assessing fuel switching in certain Interior and rural communities from diesel to cleaner burning propane to provide information for the likelihood of economic natural gas "hub" propane processing facilities.

Recommendation:
The State should sponsor a comprehensive economic and environmental study of assessing broader electrical power distribution to certain Interior and rural communities to provide information for the likelihood of economic power generation plants near natural gas "hub" offtake points.

Recommendation:
The State should encourage private investors to initiate an economic study of creating one or more gas "hubs" for gas distribution, natural gas liquid processing, and/or power generation near Fairbanks, with a spur line to Anchorage and other "hub" locations that could distribute to Valdez and Southeast Alaska cities. This would foster a broader clean energy natural gas, propane and electrical distribution system within Alaska once a pipeline is endorsed across Alaska.

"My message to you is do everything possible to use as much of the raw product in-state; in our homes, in our cars...and in the many, many products we can create."

Kenai Mayor John Williams, Kenai hearing

Goal #3: Assess the costs or benefits of the State taking its royalty share "in-kind" for facilitation of in-state access and use.

Recommendation:
The State should retain its right to take its royalty share of gas on the North Slope "in-kind" or "in-value." This flexibility creates competition to maximize wellhead value for the State by either the producers or other firms such as energy trading companies interested in marketing the State's share of gas. The producers have requested a long-term commitment by the State and are asking the State to decide up front to take either "in-kind" or "in-value." The Council



Lt. Governor Fran Ulmer talks with Soldotna City Manager Tom Boedeker and State Rep. Mike Chenault. The residents of Kenai expressed to the Council the importance of future access to North Slope gas for the Peninsula.

TERMINOLOGY GUIDE:
Definitions of terms used in this section

Basin: A term usually referring to a region of sedimentary rocks ("sedimentary basins") that have potential for oil and gas discoveries. The "Cook Inlet Basin," for example, refers to the region, not just the offshore producing fields of Cook Inlet.

Natural gas generation and migration: Geologic terms referring to the creation of hydrocarbon fluids in underground rocks and the "migration" (movement) of the fluids into trapping mechanisms, potential reservoirs, in underground rocks.

Methane gas from coal seams: Methane (the main component of natural gas) is a common emission from coal seams. It is a safety hazard in coal mines, for example.

Gas hydrates: Methane (gas) that is frozen as a solid phase in rocks, such as in the permafrost of the North Slope. As pressure is decreased and temperature increased, gas is released from the hydrate. Gas is not now commercially produced from hydrates, but research on their potential is under way.

Railbelt: A term referring to the state's major population areas of Southcentral and Interior Alaska that are served by the Alaska Railroad and other surface transportation infrastructure.

Propane: One of the natural gas liquids associated with gas production. It is sold as a pressurized liquid for fuel, and also has other uses.

Spur line: Informal term for a smaller pipeline connecting to a larger pipeline. For example, a pipeline connecting Anchorage, or Valdez, to a large-diameter pipeline along the Alaska Highway route is being referred to as a "spur" pipeline. The idea is that smaller "spur" pipelines would be built after the main, larger, pipeline is in operation.

feels the flexibility to switch on six months notice is very important, creates marketing competition, and ultimately maximizes resource value. The State should not negotiate away its right to take its royalty share of gas "in-value" or "in-kind."

Recommendation:
The State could maximize the value of its natural gas royalty resource with a mixed portfolio of "in-value" and "in-kind" sales, with in-kind royalty marketed by energy trading companies such as Duke Energy, Enron, Williams Energy or major companies like them. The State should put its royalty "in-kind" gas out for bid and seek bids from multiple parties for contract terms and price. Such contracts should ask for a "floor price" equal to or exceeding the average netback wellhead price achieved by the three major producers or from "in-value" sales as "insurance" that the energy trading companies are working in their marketing to beat the producers' gas sales realization.

Recommendation:
When there are out-of-state sales using an energy trading company, the energy trading company will reserve the capacity and the liability associated with that capacity, and that liability will not fall back on the State.

Recommendation:
The State may choose to direct market some portion of its gas to in-state consumers using State staff, but it is recommended that sales to customers in outside markets be handled by professional energy trading firms, considering the complexity of and rapid change in those markets. This would also allow those firms to absorb the risk of nominating pipeline capacity and buying hedging instruments to lessen risk on pricing of contracts.

Recommendation:
By keeping some portion of its royalty share of natural gas "in-kind," the State may be able to make some contract deals with consumers in-state at more favorable terms than the producers, as the State might realize added dollar benefits through jobs and corporate taxation of value-added processing such as natural gas liquids processing, petrochemical manufacturing, power generation, etc. that may not otherwise be economically viable to entrepreneurs within the state. However, there should not be a subsidy in sales of royalty-in-kind gas. The State should receive a netback price for royalty gas equal to or greater than the market-based "netback value" of gas on the North Slope.

Recommendation:
To the extent practical, the State of Alaska should enforce its "higher of " clauses on natural gas royalty as this could add value and ensure producers work hard in their marketing to obtain the best value in their sales of natural gas. When the State elects to take any share of its royalty gas "in-value," existing lease terms and statutes allow the State to receive royalty payments and production taxes on the "higher of" actual proceeds or market value. Other states, as well as the U.S. Minerals Management Service, are aggressive in ensuring all producers pay this "higher of" price for royalty and relevant taxes and receive such payments from the same producers that produce on the North Slope.

Recommendation:
Because of the complexities of the natural gas industry and the differences with the oil industry, the State should form a Natural Gas Services Group with people experienced in the natural gas industry, shipping, marketing, and trading so that the State becomes even more sophisticated in understanding deals and transactions that are often involved in the natural gas business. The group would provide an oversight function on sales of royalty gas out-of-state, but could also negotiate and manage in-state sales much like the Division of Oil and Gas now manages sales of royalty oil.

Recommendation:
For more cost effective development of in-state gas infrastructure resulting in more economical transportation of state royalty gas within the state, the State should encourage entities to examine the port authority concept of tax advantaged financing for a gas "hub," spur lines, and other distribution facilities.



Howard Mermelstein testifies at the Council's first public hearing in Fairbanks.

"A key component of the Alaska gasline must be how the rest of the state is going to benefit from North Slope natural gas."

Dave Dengel, City Manager, City of Valdez

Goal #4: Determine the "best practices" for methodologies to achieve transparency in netback pricing valuation at the wellhead and transportation to assure fair and favorable pricing for in-state gas business creation and expansion as well as for taxation and royalty calculations.

Recommendation:
The State should keep a natural gas price netback valuation methodology based on actual sales proceeds, or sales contracts, and not change to a formula linked to average prices in gas trading hubs or some other general formula at least for the first several years of major gas sales. The State's right under lease terms and statutes to obtain actual realized prices for its gas and natural gas liquids should not be negotiated away.

Recommendation:
With the growing natural gas liquids (NGLs) business in the U.S., the State should keep a natural gas liquids price netback of gas-line liquids based on actual sales proceeds, or sale contracts, of the liquids and no accept a value for the liquids based on a Btu adjusted basis of the gas stream unless there is clearly a higher value obtained by Btu-based sale. The State should be very sophisticated in its assessment and knowledge of the business of NGLs, as revenues from NGL sales will be a substantial part of revenues from the overall gas stream.

Recommendation:
Alaska statutes should be reviewed and updated to require information on sales spot transactions, sales contracts, actual transportation costs, and other information be made known to the State, much as statutes in Texas and other locations provide for. When updating these statutes the process should be clarified in a way that assesses the "lessons learned" on the Alaska oil valuation disputes and provides for more timely resolution of any differences in valuation.

Recommendation:
Alaska statutes should be reviewed and updated to require information on "affiliated sales" by producers be made known to the State, much as statutes in Texas and other locations provide for.

Goal #5: Recommend policies that assure clear and transparent rules for access to natural gas into and out of the gas pipeline for Alaska businesses and customers.

Recommendation:
The State must develop a clear and sophisticated understanding of the "open season" rules governing access to a contract carrier pipeline and devise strategies to facilitate access to the pipeline for firms exploring for or developing new gas discoveries on the North Slope or Interior basins.

Recommendation:
The State should incorporate in any federal legislation the right to gas access in-state. This right is provided in ANGTA but is not provided in the producers' recently proposed federal legislation.

Recommendation:
The State should first seek federal legislation that gives the Regulatory Commission of Alaska (RCA) authority to set tariffs for the transportation of intra-state gas used in-state similar to that authority given to the RCA for tariff review on the TAPS oil line. The state RCA should review applications for pipeline access within the state to ensure fairness in pre-determined fees and terms based on reasonable rates of return for investors who ship to in-state consumers.

TERMINOLOGY GUIDE:
Definitions of terms used in this section

Royalty share of gas: The State of Alaska, as landowner, receives a royalty, or share, of production. At Prudhoe Bay the leases provide for a one-eighth (12.5 percent) share. Oil and gas leases issued more recently provide for one sixth (16 percent) and sometimes one-fifth (20 percent) royalties.

In-kind, in-value: Under the terms of its leases, the State can take its royalty "in-value," allowing the producers to sell the oil or gas and pay the State cash. The State also has the option to take the royalty "in-kind," (physically taking control of the oil or gas). In this case the State sells the royalty oil or gas to another party. The practice is for the party buying the "in-kind" royalty oil or gas to arrange for transportation. When the State is paid "in-value" by the producers, they must transport the royalty oil or gas.

Floor price: A minimum price in a contract.

Average netback wellhead price: "Wellhead price" is the value of the oil or gas at the well in the producing field. In Alaska it is determined by subtracting transportation costs from market sales prices. An "average" netback price is the weighted average of the netback prices reported by several leaseowners in a field, which can vary because leaseowners usually sell their oil or gas to different customers.

Energy trading company: A company, or division within a company, that buys gas or oil from producers and sells to others. Energy trading has developed into a large, complex, sophisticated business in recent years.

Capacity: Physical space in a pipeline. A producer typically buys "capacity" in a pipeline to ship gas, for example.



Council member Ken Thompson addresses the group at the Fairbanks public hearing.

Recommendation:
Failing to achieve RCA obtaining sole authority in-state, the State should seek through federal legislation the creation of a joint board between the Regulatory Commission of Alaska and the Federal Energy Regulatory Commission (FERC) that would have authority to set tariffs for the transportation of intra-state gas used in-state. This joint board should participate in review of applications for pipeline access within the State to ensure fairness in pre-determined fees and terms based on reasonable rates of return for investors who ship to in-state consumers.

Recommendation:
Alaska should consider including a "fairness" clause in the granting of State right-of-way approvals across state lands to guarantee fair access, similar to provisions developed by Texas for pipeline rights-of-way approved across state lands. Such a clause will give the State valuable leverage in negotiating fair access rules. The clause could also provide an avenue for appeal to the RCA in the event of disputes.

Recommendation:
The State should complete a thorough socio-economic study of various approaches to in-state natural gas pricing of in-kind royalty gas.

One approach is that the sales price of in-kind royalty gas or gas liquids to in-state users, whether private or State, be based on the market netback price of gas on the North Slope (which is determined by subtracting actual pipeline transportation costs from actual realized market sales prices in the lower 48 or other outside markets) adjusted for intra-state tariffs actually incurred for the transportation of the gas to the in-state access point, or hub, and then transportation costs to the consumer with allowance for a reasonable rate of return on investment. Price of gas or gas liquids to in-state users should not be based on comparisons with alternative fuels, such as diesel. Providing that the intra-state tariff is determined on a prorated basis and not the "postage stamp" methodology, this policy will create a supply of reasonably priced, clean energy for communities in Interior Alaska, and ultimately Southcentral Alaska if a spur line is built. These more affordable natural gas prices would be passed along to consumers who purchase from a regulated utility but may not be passed along to consumers who purchase from a non-regulated company. A problem with this approach is that the State receives a potentially lower netback value than if the price is determined through competition with other fuels. This may favor the consumers in that area at the cost of lower State revenues. On the other hand, such an approach could mean more affordable natural gas to a large number of customers who purchase from regulated utilities, potentially enhancing economic development and quality of life for businesses and consumers.

Another approach is that the sales price of in-kind royalty gas or gas liquids to in-state users should be based on being competitive with the pricing of alternative fuels, as that may create higher netback prices resulting in higher royalty and tax revenues to the State. This would potentially increase the revenue received by the State but would not significantly lower the costs of consumers using this in-kind gas or gas liquids. However sellers other than the State could compete for these higher netback markets and so drive the price down well below the alternative fuels.

Goal #6: Assess pipeline sizing and the pipeline "contracted volumes" structure for growth of in-state use and/or potential future export markets to Asia and the West Coast, or expansion of deliveries to the lower 48.

Recommendation:
The State should investigate ways of working with pipeline transmission companies as investors to build in excess capacity, to provide space for transporting new gas that will be discovered on the North Slope or Interior basins.

Recommendation:
The State should evaluate innovations in using part of its "in-kind" royalty share in contract sales to energy trading companies who can bid for shipping capacity which then may be used in a creative way in the future to ship gas from new discoveries while the State elects at the time of new discoveries to change and sell the originally nominated royalty gas volumes "in-value."

Recommendation:
The State should seek an order by FERC, or federal legislation, for periodic open-season nomination periods, to allow for additional capacity to be built for new gas, when triggered by requests from existing or potential producers, transporters, shippers, customers or the State.

Goal #7: Evaluate conceptual options for future value-added projects during the 50-year life of gas reserves for in-state use and/or export to Asia and the U.S. West Coast.

Recommendation:
No one can rule out with certainty the viability of value-added processing of natural gas in Alaska over the next 50 years. Alaska should have a natural gas pipeline that allows this option to remain open. The previous recommendations regarding access, reasonable tariff and pricing, and capacity expansion will keep these options open.

Recommendation:
Gas and gas product markets are highly cyclical in price and somewhat cyclical in demand, and somewhat regional in nature; thus the State should facilitate a pipeline option that will allow access to multiple markets in the future.

Recommendation:
As markets change, the State should take a proactive role in encouraging investors to consider the possibilities for liquefied natural gas (LNG), gas-to-liquids (GTL), expanded uses of natural gas liquids (NGLs such as propane, butane) and downstream processing such as petrochemicals.

Goal #8: Determine strategies to promote and attract investment for in-state distribution and value-added processing.

Recommendation:
The State should develop and periodically update a formal marketing plan to attract investors in Alaska who may be interested in in-state gas distribution or development of value-added industries. Assisting with this could be an additional function of a new Natural Gas Services Group within the Department of Natural Resources.

Please see full report for this committee's complete recommendations and conclusions.



Gas Policy Council Co-Chair Frank Brown talks with Fairbanks residents at a public hearing reception held at the Chena River Convention Center.

TERMINOLOGY GUIDE:
Definitions of terms used in this section

Nominating pipeline capacity: When a producer "nominates," or proposes, to ship oil and gas through the pipeline. Pipeline companies usually have specific periods in which they accept such nominations.

Value-added processing: When "value" is added to a raw resource, such as oil or gas, by processing, refining or manufacturing it into another product, such as fuel, fertilizer or a petrochemical product. Since value-added processing or manufacturing is capital and often labor intensive, it brings new investments, jobs and tax bases into a region. Examples are plants making fertilizer and LNG near Kenai, and fuel refineries near Kenai, Fairbanks and Valdez.

Gas "hub": A connection to a gas pipeline where gas can be taken off. Gas is often bought and sold at hubs.

"Best practices" methodologies: Best procedures, best methods.

"Transparency": Clarity in terms and conditions; easily understood.

"Netback pricing valuation": Determining a local value, for pricing purposes, of gas or oil by subtracting transportation (pipeline) costs from destination markets where the gas or oil is sold.

"Realized prices": Prices actually achieved in market sales (i.e. not value established through a formula).

Natural gas liquids: Components of natural gas other than methane, such as ethane, butane, propane and pentane. These are valuable, and are usually sold separately from the methane, which is used mainly as fuel.

Btu: British thermal unit, a common unit for measuring energy content.

State Pipeline Ownership and Tax Structure
Bill Corbus, Chair

Members
Dave Rose, Ron Duncan, Grace Schaible,
Mike Navarre, Ed Rasmuson, Mike O'Connor, Ken Thompson

Committee examined the following topics
- State promotion and facilitation of project financing – State ownership
- Evaluation of State tax structure

Committee Meetings
- April 5, 2001, Anchorage
- May 24, 2001, Anchorage
- July 11, 2001, Anchorage
- August 13, 2001, Anchorage
- September 21, 2001, Anchorage
- October 3, 2001, Anchorage

Recommendation:
The committee believes the pipeline is economically feasible for certain investors and should be undertaken with private financing. We recommend against direct State investment unless there is clear evidence of economic benefits to Alaska that cannot be achieved through other regulatory or political mechanisms.

Recommendation:
The committee encourages exploration of creative financial structures to facilitate all or part of a gas pipeline and/or in-state gas infrastructure, provided such entities finance their activities through private markets.

Recommendation:
The committee recognizes that State tax policy is one of several tools that could play a role in influencing pipeline development, but reserves a decision. It is premature to decide how to use this tool until there is more definition of a project and the nature of its ownership.

"A project of this value can help improve community infrastructure. It's not unrealistic to think that better schools, transportation and health care can be a result of a project like the gas pipeline."

Steve Ginnis, President, Tanana Chiefs Conference, Fairbanks hearing

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Conclusions:
- When the committee began its work early in 2001, there appeared to be certain problems that could be resolved by partial State ownership in a gas pipeline, and that it could be an important advantage for Alaska. However, through the process of gathering information and holding meetings, the committee has determined that most if not all of these could be resolved through other means, other tools the State has at its disposal. For example, access to and from a pipeline can be facilitated through the state Regulatory Commission of Alaska working with the Federal Energy Regulatory Commission, and through stipulations in a right-of-way lease across State lands.

- The committee believes a natural gas pipeline from Alaska would be a good investment, but there are other, equally good investment opportunities for public funds that entail less risk. The State has a policy of diversifying investment of its assets (the Permanent Fund is an example) to reduce risk.

- From information gathered during hearings, the committee has concluded that, absent majority or total ownership of a natural gas pipeline, an ownership interest gives the State no right to capacity in the pipeline. Capacity in a contract carrier pipeline is obtained through the nomination process during an "open season."

- The committee is not persuaded that partial ownership of the pipeline raises any conflict of interests for the State (i.e. a State "ownership" interest vs. a State responsibility to regulate the pipeline) that cannot be resolved.

- The committee investigated alternative sources of financing, including the Permanent Fund, Constitutional Budget Reserve and the ability of various public authorities to issue revenue bonds. The committee believes that private sector companies can raise needed funds based on adequate coverage and financing reserves. State participation would not enhance the acquisition of funds, would not necessarily guarantee lower financing costs and might unduly interfere with a straightforward private sector funding. The State's participation would include a vote on a tariff but its interest would not be proportionately large and it would not guarantee a desired outcome.



Council member Ron Duncan confers with Governor Knowles on State ownership issues.

• Absent a compelling public interest for partial State ownership, ownership of the pipeline is best left to private industry, and to firms which are experienced in oil and gas and the pipeline business.

• The committee suggests that Alaskan-owned businesses, such as Alaska Native corporations, have the opportunity to invest in a natural gas pipeline project.

• Regarding alternative financing mechanisms, the committee has been told by the producers' group that an investment in a gas pipeline might not meet the rate-of-return criteria for the producing companies. If so, alternative financing mechanisms, such as through a public authority, might facilitate others, such as pipeline transmission companies, becoming involved. A public authority may have advantages in terms of exemption from federal income tax, or jurisdiction by the Federal Energy Regulatory Commission.

• Regarding tax policy, the producers are seeking simplification and clarity in natural gas tax and royalty administration.

• The Gas Policy Council itself has endorsed the governor's proposals for federal tax incentives, such as accelerated depreciation, an investment tax credit and a gas price volatility protection mechanism, a tax credit that becomes effective if prices fall below a certain point. The committee reaffirms this endorsement.

• The committee feels that if a viable proposal for a pipeline is put forward and the producers do not respond in a reasonable period of time, the State should use the tools that it has available to facilitate the project moving forward.

• The committee recommends finding a mechanism for a "contract" between the State and a sponsor of a gas pipeline project that would encourage a State fiscal policy as well as a stable State revenue policy. While there are legal limits to the Legislature's ability to guarantee future tax policy, such a contract would carry an important moral commitment, and would be worthy of consideration for an Alaska Highway gas pipeline.

• Different forms of pipeline ownership will affect the interests, and incentives, of the parties involved. Overall, the State has an interest in keeping costs of a pipeline down, and transportation tariffs lower, to maximize State revenues. (State revenues are based on the "wellhead" values of gas on the North Slope, after transportation.) If the producers build the pipeline, they will have an interest in maximizing production revenues, similar to the State, but will have less interest in keeping tariffs low because they are also pipeline owners. If an independent pipeline company consortium owns the pipeline, the producers' interests will be only in maximizing production revenues. In that scenario, the producers' interests would be aligned with the State's in seeking low tariffs for transportation of gas.

TERMINOLOGY GUIDE:
Definitions of terms used in this section

Regulatory Commission of Alaska (RCA): The state regulatory commission that has authority to set rates and make decisions affecting intra-state pipelines. RCA also regulates telecommunications and public utilities in the electricity, water, sewer and solid waste fields.

Federal Energy Regulatory Commission (FERC): The federal regulatory commission that has authority to set rates and make decisions affecting interstate shipments of natural gas, as well as telecommunications and electricity.

Contract carrier pipeline: A pipeline (usually gas) that has volumes committed for shipment. Pipeline owners design capacity to handle the volumes contracted for. Unlike common carrier pipelines (usually oil), owners of gas who have not contracted for pipeline capacity have no guarantee their gas will be shipped.

Alternative financing mechanisms, such as a public authority: Public-owned entities like authorities are formed to carry out specific tasks, and are usually tax-exempt. Alaska's International Airport Authority is an example. The proposed Alaska Gasline Port Authority is another.



Bill Corbus, Brian Davies, Peg Tileston and Charlie Cole participate in the Barrow hearing.

Environmental Considerations
Peg Tileston, Chair

Members
Brian Davies (vice chair), Esther Wunnicke, Lee Gorsuch, Grace Schaible

Committee examined the following topics
- Key environmental issues, both natural and human, associated with the construction of a natural gas pipeline.
- Recommendations for policies and procedures necessary to ensure that the design, construction and operation of the natural gas pipeline will proceed in an environmentally sound manner.
- Potential environmental benefits of a natural gas pipeline.

Committee Meetings
- April 5, 2001, Anchorage
- August 2, 2001, Juneau
- September 25, 2001, Anchorage

Recommendation:
Endorse the Alaska Highway gas pipeline route as the environmentally preferred pipeline route that minimizes the potential adverse environmental effects and maximizes potential environmental benefits to Alaska.

An Alaska Highway route would limit the gasline to an existing corridor, minimizing impacts to the environment as well as to fish and wildlife. It would also allow Alaska communities access to a cleaner, more efficient fuel. In addition, a highway route following the TAPS line would make oversight of both lines more efficient and effective. At hearings of the Gas Policy Council, Alaskans voiced overwhelming support for the environmentally preferred southern route.

A rigorous environmental review should be required. There are three approaches to this. The most expeditious approach but the one most susceptible to challenge is to meet the requirements of Section 5, subsection III of the President's Decision relating to the Alaska Natural Gas Transportation System which anticipated the development and public review of detailed plans to protect the environment using the best of current science and technology. The two other approaches are either a supplemental environmental impact statement (EIS) building on the ANGTS EIS or a full EIS done in an expedited manner using information from the ANGTS EIS. The outcome of any process should spell out for public review the alternatives associated with the highway route, the environmental pros and cons associated with them, and mitigation measures that should be taken to avoid or minimize adverse impacts.

Any frontier route would require a "start from scratch" approach, including collection and analysis of physical, biological and social data and determination of required technology.

Recommendation:
Adequately fund and staff a natural gas pipeline office that is housed in one place to facilitate communication, coordination and cooperation among all affected state, federal and Canadian agencies.

Lack of timely and complete communication among agencies can have severe consequences on any project, but can be particularly difficult in one of this size. A facilitated review of the JPO operation by all the involved agencies to note procedural changes they might recommend to improve effectiveness and efficiency would be beneficial. Acquiring personnel with the necessary technical and scientific expertise may be difficult for both federal and state agencies when competing with industry, which will be hiring for the same positions and will have considerably higher salary scales. Every effort should also be made to include the considerable number of borough and local agencies concerned with the various project alternatives, along with Alaska Native corporations, tribes, and villages that will be affected by a pipeline right-of-way (ROW).

Recommendation:
Recommend that the Gas Pipeline Office (GPO) conduct a thorough review of "lessons learned" from TAPS design, construction and operation. This review should include public comment and public participation. Use "lessons learned" to develop procedures for the gas pipeline that ensure past mistakes are avoided and successes repeated.

A natural gas pipeline following the TAPS/Alaska Highway corridor will have many environmental concerns similar to those of the earlier project. Certain differences need to be identified and addressed, such as the effect of a buried, chilled pipeline crossing beneath streams, geologic and hydrologic data for areas where TAPS is not buried, and design and operational differences between a low-pressure, hot oil line and a high-pressure, cold gas line. In addition, Canadian and other high-latitude gas pipelines should be studied for lessons learned.

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672
2953 SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPLINES, 2001-02

Recommendation:
Establish an open and available data and information process for the public, agencies and industry.

Frustration and suspicion take hold when individuals, organizations and communities are unable to get information on issues of concern in a timely and appropriate manner. Such a process should start at the beginning of the project and make available all non-proprietary material. Meaningful involvement by affected communities is important. Effort should be made to include all stakeholders, not just decision-makers. Websites, e-mail addresses and information repositories, such as local libraries and borough offices should be used to disseminate information. A central site, preferably the Alaska Resource Library & Information Services (ARLIS), should be used as effectively as possible and adequately funded. An information clearinghouse such as the Exxon Valdez Oil Spill Library (which is now consolidated in ARLIS) could be an appropriate approach.

Recommendation:
Establish mandatory training for all personnel involved with the gas pipeline project.

Timely, appropriate and sufficient training is vital for all personnel associated with a major project. Such training should start with applicable federal, state, and local laws and regulations, agency mandates and responsibilities, enforcement options and penalties for noncompliance, best practices and appropriate technologies. Government and industry should coordinate to ensure commensurate levels of training for the public and private sectors, including all contractors and subcontractors. Sessions to update personnel as the project progresses should be included, along with required orientation for those joining it.

"We strongly oppose all proposed natural gaslines from Alaska's North Slope that invade frontier wilderness ecosystems with new routes and new infrastructure."

Sue Schrader, environmental advocate, Juneau hearing

Recommendation:
The state should take a long term view of the gas pipeline to minimize environmental concerns.

In view of the likely long life of this project, the state should encourage a long-term view be taken in design, construction, operation and maintenance in order to mitigate environmental risks over the entire life of the project.



Department of Natural Resources Commissioner Pat Pourchot discusses the role of his department in the pipeline permit review process.

TERMINOLOGY GUIDE:
Definitions of terms used in this section

Trans-Alaska Pipeline System: The formal name of the trans-Alaska oil pipeline, also informally referred to as the "Alyeska" pipeline. TAPS is operated by Alyeska Pipeline Service Co. but is owned by North Slope oil and gas producing companies plus Amerada Hess and Williams.

Joint Pipeline Office: A central office established by State and federal agencies responsible for pipeline oversight and regulation. Federal and State agency staffs with similar responsibilities work together, improving coordination and efficiency.

ABOUT NATURAL GAS:
What is "Gas-to-Liquids?"
Gas-to-liquids, or GTL, refers to a chemical conversion technology developed in the 1920s that converts natural gas into a liquid product from which environmentally "clean" refined products, such as diesel, can be made. A great deal of highly guarded research is now focused on improving GTL technologies so commercial plants can be developed economically. BP has a pilot GTL facility in Nikiski.

Why is natural gas a clean fuel?
Natural gas (methane) is the cleanest fuel because it has the fewest number of carbon atoms compared with hydrogen atoms relative to other fossil fuels and far fewer contaminants too, such as sulfur, nitrogen compounds, and heavy metals. Oil or coal have more carbon atoms. When burned, the carbon combines with oxygen in the air and becomes carbon dioxide, a gas suspected as the main contributor to global warming. The hydrogen combines with oxygen in the air and becomes water vapor. Because methane molecules have fewer carbon atoms than other fuels, less carbon dioxide is emitted when methane is burned.



"Our tribal council supports responsible development of natural gas – as long as it's not done through our ocean."

Patsy Aamodt, President, Native Village of Barrow, Barrow hearing

Patsy Aamodt, President of the Native Village of Barrow, testifies to the Council.

Recommendation:
A records management system for compiling and maintaining complete and updated documentation should be in place at the beginning of the project and maintained and updated throughout the life of the pipeline in accordance with professional document control standards. The State must have copies of all documents.

The TAPS experience has shown that older engineering drawings, including "as-builts" and documents confirming original facility configurations and placements, have not always been readily accessible by pipeline managers and regulators when needed. Establishing a professionally designed and maintained document control system will help to ensure that accurate records from every phase of pipeline development remain rapidly retrievable under unforeseen future circumstances. Recent advances in technology will undoubtedly aid this process.

Recommendation:
Assure that effective and adequate monitoring and enforcement systems are in place at the start of the project and continue throughout the life of the pipeline.

Adequate funding will be needed to ensure that a sufficient number of appropriately trained agency personnel are available for monitoring and enforcement throughout pipeline construction and operation. Agency personnel without a working knowledge of pipeline construction, operation, and maintenance will have little credibility with their industry counterparts. Training of agency personnel associated with all aspects of the pipeline should be integral to the project. Such training should emphasize the prevention and early detection of problems, and understanding of regulations, codes and penalties. Enforcement of regulations and codes is essential but will not occur without trained personnel who are actually available on site.

Recommendation:
Direct the GPO to establish a comprehensive citizen's involvement plan. This effort may include the creation of a citizen advisory council with representatives from communities affected by construction of the pipeline.

A determined effort should be made to aggressively involve and engage affected communities during the planning and construction phase through a coordinated federal/state effort. If necessary as determined by the federal/state plan, a citizen advisory council should be formed and adequately funded to receive and evaluate information and respond to pertinent issues. If established, the council would also evaluate their role following construction of the pipeline.

The public involvement process should also include a full review, including stakeholder involvement, of proposed federal grant and state lease right-of-way provisions and stipulations.

Recommendation:
Provisions should be incorporated into ROW lease agreements to ensure that adequate dismantling, removal and restoration (DR&R) funding will be available for the Alaska segment of the natural gas pipeline.

The actual DR&R provisions will depend on ownership of the pipeline and should take into consideration the true long life of the asset.

Recommendation:
Perform a full security review and develop a comprehensive and detailed security plan early enough to influence the pipeline design and alignment process.

Heightened security concerns throughout the United States should be reflected in the engineering design and alignment of the natural gas pipeline, which will be a significant part of America's domestic energy supply. Any aspect of the design of pipeline facilities and structures that would be particularly vulnerable to sabotage, such as compressor stations, bridge crossings and above-ground valve housings, should receive attention from a security standpoint early in the design process, and not as an afterthought. This concern applies also to the alignment, which may preser. opportunities for modifications or adjustments that will minimize the potential for harm.

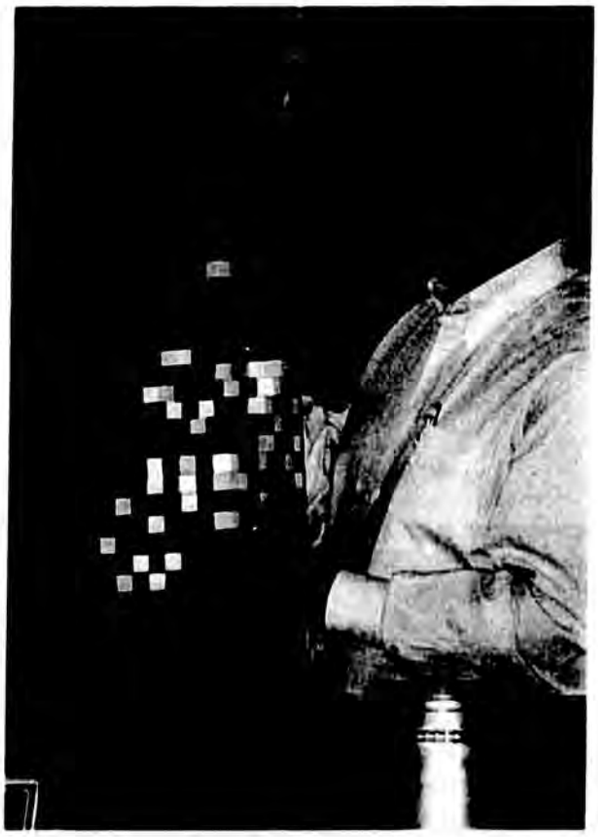
Recommendation:
Continue to ensure that environmental scientists and permitting specialists work side-by-side with design engineers and construction planners from the earliest stages of the project through to its completion.

It is essential that environmental safeguards be built into the design of the project, not added as an afterthought to satisfy regulatory requirements and stipulations. Preliminary engineering design products will be used to support major permit applications with long lead times and must contain fully integrated environmental features at that early stage. This can best be accomplished if environmental and permitting specialists work on the same teams and in the same facilities as the engineers.

Recommendation:
The State of Alaska ROW lease should require long-term environmental surveillance and monitoring, and annual reporting. This function should continue throughout the life of the pipeline.

Recommendation:
The GPO, in cooperation with the federal government, should continue to coordinate the trans-boundary aspects of construction, operation and maintenance of a gasline, including operations control and emergency response.

Although it may cross land belonging to two nations, the gas pipeline will be a single integrated system. Emergencies, whether structural, operational or environmental, will not respect the international boundary. The U.S. and Canada must establish integrated control protocols that can regulate the pressure and flow of gas through the pipeline as a single system and thus respond quickly and effectively to emergencies. This will require open communications, shared data, and a close working relationship between personnel of both nations. The State should look to other international pipelines, particularly between Canada and the United States, for models in handling the trans-border oversight aspects of construction, operation and maintenance.



Steve Arbelovsky of Phillips explains to the Council the properties of liquid natural gas.

ABOUT NATURAL GAS:

How much gas do we have?
Alaska's North Slope is estimated to hold about 35 trillion cubic feet (tcf) of proven natural gas reserves. Twenty-six tcf of this is in the gas cap of the large Prudhoe Bay oil field. The remainder is mostly in the undeveloped Point Thomson gas field east of Prudhoe Bay, and in other oil fields on the Slope.

Geologists think there could be as much as 100 tcf, or more, of gas that can be discovered and commercially produced on the Slope, and more gas in unexplored areas of Interior Alaska.

Until recently, exploration on the North Slope was for oil. However, gas was discovered during the course of that exploration. Companies are now exploring exclusively for gas, and geologists are confident more will be found.

What competitive advantages does Alaska have in marketing its gas?
The large gas reserves on the North Slope are proven by drilling and ready to produce. In other places, like Canada's Mackenzie Delta and the U.S. Gulf of Mexico deep offshore, more exploration and development must be done to prove reserves. The North Slope gas reserves are a certainty, and are the largest proven undeveloped gas resource in America.

Alaska will also be a dependable and secure source of long-term supply for the nation. Gas from the Canadian Arctic could also fill some of this need. The alternative to a gasline is more dependence on imported liquefied natural gas (LNG) from uncertain and possibly unfriendly foreign sources.

Federal/International Action
Charlie Cole, Chair

Members
Esther Wunnicke, Bob Penney, Jon Rubini, Jeff Feldman, George Wuerch

Committee examined the following topics
- Federal permitting/access
- Federal agency lead
- Canadian permitting/access
- Other contractual considerations
- Domestic markets – competing sources/sharing of the market
- Canadian national and territorial relations

Committee Meetings
- May 24, 2001, Anchorage
- August 2, 2001, Juneau
- September 7, 2001, Anchorage
- September 25, 2001, Anchorage

Members of the Gas Policy Council were extensively involved in decisions on State policy and in the development of proposed legislative changes. A substantial product of the Federal/International Action Committee were recommendations for changes to federal law to address key concerns of the State of Alaska in the development of a natural gas pipeline.

The committee supports modifications to modernize ANGTA and believes such modifications would be beneficial to an Alaska gasline project. The committee endorsed 10 key policy goals that should be included in any new gasline legislation.

The 10 policy goals developed to guide drafting of the legislation were debated by the full Council and ratified in concept by a majority of its members on September 25, 2001. Several changes were made as a result of points raised by Council members during the September 25 debate.

If Congress moves forward with new legislation as suggested by the producers, a principal concern of the Council is that Congress should take steps early to reaffirm the southern, or Alaska Highway, route as the sanctioned route for a natural gas pipeline, as a previous Congress did in 1977 when it ratified the President's choice of the southern route under the Alaska Natural Gas Transportation Act. Such a step would focus the attention of industry and federal agencies on regulatory and permit approvals for a project along this route.

This committee also notes that a southern route provides several advantages over other alternatives. Among these is use of the pipeline corridor for other purposes, including the possibility of constructing a railroad or other utilities over time. In addition, a southern route could facilitate access to highly mineralized areas which are located in close proximity.

A second concern of the Council was the probability that with a new initiative in Congress, an Alaska gas pipeline would be subject to Federal Energy Regulatory Commission jurisdiction on issues important to Alaska without a defined role for the state with the FERC. Such issues would include tariffs on intra-state shipment of gas, and access to and from a pipeline. The proposal for a joint board that would give the Regulatory Commission of Alaska joint jurisdiction with FERC on issues affecting Alaska grew out of this concern.

Other concerns of the Council involved provisions to encourage hiring of residents of Alaska for a gas pipeline project, and the hiring of Alaskan Natives.

"Alaska resources should be developed to benefit Alaskans."

Robert Wilkinson, CEO, Copper Valley Electric Association

It was recognized by the Council that the pipeline project will be substantial and that, for all practical purposes, qualified Alaskan workers wishing to work on the project will be employed. Still, an explicit encouragement to hire locally will be a strong inducement for companies and unions to train Alaskans for pipeline-related construction and operating jobs. The skills developed in the Alaskan workforce as a result of training and employment will thus be a lasting legacy of the project.

The Council also considered the importance of pipeline access and the need for future open seasons to facilitate pipeline access for new discoveries. Failure to provide for additional capacity either at startup or through future open seasons could create a "monopoly" on pipeline capacity, discouraging exploration by non-owners. Any new gasline legislation must address this issue to protect the interests of the State of Alaska.

Other policy points guiding development of proposed legislation are detailed later in this report. The committee recognizes the governor's strong advocacy of the 10 principles, as reflected in his recent testimony before the Senate Committee on Energy and Natural Resources and in other forums. It would appear that the State's policy position is well understood by decision makers in Congress and the Federal Executive Branch.

With this in mind, the committee believes that it would be useful for the State Administration to continue its efforts with the commercial parties to develop a market driven solution to transport Alaska natural gas to market via the Alaska Highway route.

Close coordination and communication between the State, the North Slope producers and the pipeline companies could facilitate the establishment of a consortium of companies with the financial capability to build the pipeline.

In our opinion, current discussions among the parties concerning economic feasibility and reestablishment of the previous pipeline partnership underscore the need for such coordination at this time.

Background on Canadian Relations

First Nations
The Kaska First Nations located in Northern British Columbia and the Yukon continue to negotiate land claims and self-government agreements with the Government of Canada and the Province of British Columbia. While these negotiations are expected to continue for the foreseeable future, speculation is that when the time is right, the Kaska will be open to a side agreement on any proposed pipeline running through their territory.

The eight First Nations who have land claims along the proposed route of the Mackenzie Valley pipeline have been negotiating with producers since late spring of 2001. Early in October of 2001, seven of the eight groups came to an agreement on ownership sharing of any pipeline built through their territories. This agreement would grant 30% ownership to the First Nations Bands. The eighth, the De Cho, refuse to sign the agreement. While the Minister of Indian Affairs and Northern Development has been quoted as saying that one Band cannot hold a veto over any project, the De Cho believe that they have the right to refuse construction on lands they claim.

Position of the Government of Canada on Arctic Gas Production and Transportation
The Government of Canada has affirmed that in relation to this project, all departments and agencies will maintain route and project neutrality. In the spring of 2001, the Prime Minister set



Governor Knowles, Mayor Boyles and Charlie Cole listen to testimony at the Fairbanks public hearing. Interior residents expressed their strong need for access to natural gas.

TERMINOLOGY GUIDE:
Definitions of terms used in this section

ANGTA: Alaska Natural Gas Transportation Act, passed by Congress in 1976, which designated the Alaska Highway route for a North Slope pipeline and selected a consortium led by Northwest Energy, of Utah, to build the pipeline. (Foothills Pipelines now owns rights to the system.)

ANGTS: The Alaska Natural Gas Transportation System is the formal name for the Alaska Highway pipeline project approved by Congress in 1977.

North Slope gas producers: Companies that own rights to produce gas. Major Alaska gas producers are BP, ExxonMobil and Phillips. The State owns 1/8 royalty.

Tariffs: Charges, or fees, charged by pipeline owners to firms or entities shipping natural gas.

Intra-state: Referring to shipments within one state, as opposed to interstate shipments from one state to another.

First Nations: Term under Canadian law for Native American groups.

Gas liquids: Valuable components of the natural gas stream, such as ethane, butane and propane.

Petrochemicals: Industrial products made from hydrocarbon (gas or oil) feedstock.

ABOUT NATURAL GAS:
Why is gas in demand?
Mainly because of its clean-burning characteristics, a major advantage in meeting clean-air requirements, and because gas-fired turbines for electricity generation have improved in efficiency, with sharply lowered costs. In the long-term, demand for gas used to generate electricity is expected to grow, although demand for gas for industrial and home-heating will also continue to grow.

up a Cabinet reference group to study the current state of Canada's energy policy. The main issue of study was whether to express a preference for one route over another. A number of Cabinet Ministers expressed support for either the "over-the-top" route or a two-pipeline route with the construction of the Mackenzie Valley line happening first. After careful consideration of all available information and a careful review of the regulatory implications of each option, the Cabinet reference group recommended to the Prime Minister that the original position of route and project neutrality be maintained.

Provincial and Territorial Positions

Of the four non-federal jurisdictions involved in the issue, only the Yukon Territory is firmly supporting the Alaska Highway route. While they have not been overly aggressive in the past, they intend to become more aggressive in promoting the route with the Canadian Federal Government. The Yukon Government has commissioned an economic study of the benefits to Canada of constructing and operating the Alaska Highway route and it is expected that this study will be released to the public in January of 2002.

The Northwest Territories is aggressively promoting the Mackenzie Valley line either in conjunction with an "over-the-top" segment or as a stand-alone line. Assuming the latter is chosen by producers, the Northwest Territories is demanding that this line be built before an Alaska Highway gasline. They are very active with the Federal Government asking for financial incentives to ensure the line's construction.

The other two jurisdictions involved, British Columbia and Alberta, have remained route and project neutral. Premier Klein of Alberta has said that regardless of what line is built, he will not allow a "bullet line" to cross his province. He demands that Albertans share in the long term economic prosperity created by a line to the lower United States. Principally, he is referring to gas liquids and would like to see the petrochemical industry in his province benefit from them.

While it would seem logical for the Government of British Columbia to be supportive of the Alaska Highway route, this government has only been in power since June 2001 and this issue has yet to be critically examined by the Premier and his Cabinet.

Recommendations:

The committee endorsed 10 key policy goals that should be given consideration in any new federal gasline legislation. The 10 principles and corresponding legislative provisions are outlined below.

Key Principles

- Find that the Alaska Highway natural gas pipeline is in the national interest.
- Mandate the already permitted Alaska Highway route as the preferred route.
- Provide opportunities for new pipeline participants, such as existing producers, pipeline companies, and major Alaska companies.

Corresponding Legislative Provisions

- The 1976 Alaska Natural Gas Transportation Act (ANGTA) that established a process selecting the ANGTS project following the Trans-Alaska Pipeline and the Alaska Highway through Canada to the lower 48 should be the framework for any new gasline legislation.
- The legislation should provide for updating and modernizing the process provided in ANGTA for the expeditious environmental review and approval of a pipeline application for the Alaska Highway route.
- A finding that an Alaska Highway route would make an important long-term contribution to the nation's energy supplies and independence.
- A finding that an Alaska Highway route would have less potential environmental impacts and related delays in construction.

Key Principles

- Provide a mechanism for Alaska communities and businesses to obtain access to natural gas from the pipeline.

Corresponding Legislative Provisions

- FERC should require the project sponsor to demonstrate how the sponsor plans to meet reasonable projections of in-state local consumption needs, including the needs of Fairbanks, Cook Inlet, and rural Alaska. In addition, the sponsor should allow for possible future construction of a pipeline to tidewater for the export of LNG.



Al Adams discusses federal legislation with Ken Freeman and Mayor Rhonda Boyles.

• The Regulatory Commission of Alaska should have concurrent jurisdiction with FERC to set just and reasonable rates for the shipment of natural gas over the Alaska section of the gasline for in-state users.
• The Regulatory Commission of Alaska should have exclusive jurisdiction to set just and reasonable rates for any lateral pipeline connected to the Alaska section of the gasline that serves in-state users.

Key Principles
• Provide access to the pipeline for new natural gas discoveries that will keep Alaska's oil and gas industry healthy through new leasing, exploration and production.

Corresponding Legislative Provisions
• FERC should require the project to establish reasonable plans and procedures, including additional open seasons if necessary, for the expansion of the Alaska section of the gasline as new fields of natural gas are developed on the North Slope and throughout Alaska.
• FERC should be authorized to order expansions of the gasline in the future under reasonable, non-discriminatory terms.

Key Principles
• Provide for Alaska hire and Alaska Native hire.
• Provide for the use of Alaska businesses.

Corresponding Legislative Provisions
• To the extent allowed by law, Alaska residents and contractors should be employed when they are available and qualified. In turn, contractors should be encouraged to employ and train Alaska residents.
• Recruitment should be accomplished primarily by advertising in-state and using Alaska's job service organizations to notify the Alaskan public.
• The project sponsors must, whenever feasible, enter into construction contracts with Alaska firms and fabricate modules in Alaska.
• The gasline sponsors should be required to enter into an agreement to provide for pre-employment recruitment, on-the-job training and employment of Alaska Natives.

Key Principles
• Provide for a project labor agreement for the construction and maintenance of the pipeline, and for worker training.

Corresponding Legislative Provisions
• The project labor agreement should require all contractors and employees to agree to a total ban on strikes, lock-outs and other disruptive activities for the life of the agreement.
• The agreement should be designed to ensure a steady supply of skilled labor and a contractually binding means of resolving worker grievances.

Key Principles
• Provide a priority for the use of American and Canadian steel.

Corresponding Legislative Provisions
• Only steel manufactured or produced in the U.S. or Canada should be used in the construction of the Alaska section of the gasline unless its use is inconsistent with the public interest or the cost is unreasonable. Factors to be considered in evaluating the public interest should include quality, availability and delivery times.

Key Principles
• Provide for economic incentives to give investors in ANGTS additional levels of confidence.

Corresponding Legislative Provisions
• Accelerated depreciation on gasline investments.
• An investment tax credit for an approved ANGTS project.
• A tax credit for producing gas from the Alaska North Slope tied to a price floor.

ABOUT NATURAL GAS:
What are we doing with the North Slope gas?
Produced gas in the Prudhoe Bay field is reinjected to conserve it and help produce more oil, as well as to fuel production facilities. Gas, oil and water come out of the ground together and must be separated. The separated gas is injected back into the underground reservoir to maintain pressure, which drives the oil to the surface. Some natural gas liquids, pentane, hexane, and so on, are mixed with crude oil being shipped through the TAPS pipeline and then sold, while other NGLs are mixed with other molecules, like CO2, ethane and propane, and reinjected into the ground to enhance oil recovery.

Who are Alaska's main competitors?
It is assumed that gas from other areas of the U.S. and Canada are not really long-term competitors with Alaska because ultimately all North American gas will be needed to meet demand. Alaska's short-term competitor is thought to be imported liquefied natural gas and gas from Canada, because if an Alaska gas project is delayed, small LNG import projects and continued development in Canada could incrementally fill market gaps that Alaska gas could have filled.

Council Members

The Co-Chairs



Frank Brown
Before retiring in 1999, Frank Brown was a senior vice president for ARCO Alaska, where he was responsible for the Kuparuk Field and the initial development of the Alpine Field.

Prior to his Alaska assignment, Brown was president of both the Thums Long Beach Company and ARCO Long Beach Company. The companies were in a risk sharing joint venture with the State of California to produce and market the State's oil and gas in the Long Beach Unit. Currently, Brown is a director of Grey Wolf, Inc., a provider of land drilling services. He is also president of Fairweather International, a consulting company focusing on Alaska North Slope opportunities.

Brown graduated from Louisiana Tech University. He has served on the Anchorage Opera Board and has been actively involved in numerous United Way campaigns.



Jim Sampson
Jim Sampson served two terms as mayor of the Fairbanks North Star Borough from 1991 to 1997 and was the State of Alaska commissioner of labor from 1986 to 1990. Sampson is currently chair of the Alaska Permanent Fund Corporation Board of Trustees and is a director with the Alaska State AFL-CIO and Alaska Works Partnership, a firm committed to training Alaskans for jobs in the construction industry.

Sampson is a 42-year resident of Alaska. He has served on the Board of Directors of the Alaska Housing Finance Corporation and as chairman of the Alaska Labor Relations Agency and Workers' Compensation Board.

The Executive Committee



Charlie Cole
Charlie Cole has had a long and distinguished career in Alaska. He began practicing law in Alaska in 1954 and has kept his private practice ever since. From December 1990 to January 1994, Cole served as the State's Attorney General under then Governor Walter Hickel. As Alaska's top attorney, he negotiated the settlement of the Exxon Valdez lawsuit on behalf of the state and its residents.

In recent years Cole has served on numerous boards and task forces, giving much of his time to help solve the policy issues facing Alaska. He recently participated in Governor Knowles' subsistence summit and has served on two other subsistence task forces.

Cole earned a B.A. and a J.D. degree from Stanford University. He had a distinguished career in minor league baseball.



William Corbus
William Corbus is president and general manage of Alaska Electric Light and Power, an investor-owned electric utility providing electric service to the City and B rough of Juneau.

Corbus has served on the Alaska State Pension Investment Board and currently sits on the board of First National Bank of Anchorage. His civic involvement has included work with the Juneau Boy Scout Council, Juneau Hospice and Homecare and Catholic Community Service.

Corbus was an officer in the United States Navy and served in Vietnam. He earned a degree in industrial engineering from Stanford University and a Master of Business Administration from Dartmouth College. He is also a registered electrical engineer.



Mike Navarre
Mike Navarre served in the Alaska State Legislature for over 10 years, where his leadership positions included finance committee chair '1991-92) and house majority leader (1989-90). He was later elected as mayor of the Kenai Peninsula Borough.

Navarre is currently the president of ZAN, Incorporated, a company that owns and operates nine Arby's Roast Beef Restaurants in Alaska. He also serves as the chair of the State of Alaska Royalty Oil and Gas Advisory Board and as president of the Boy's and Girl's Clubs of the Kenai Peninsula. He is a member of the Kenai, Soldotna and Nikiski Chambers of Commerce and is on the Nature Conservancy Board.

Navarre is a graduate of Eastern Washington University.



Ken Thompson
Ken Thompson is president of Pacific Rim Leadership Development, an Anchorage company that provides management and leadership consulting services to corporations, churches and nonprofit organizations.

Prior to his current position, Thompson spent 26 years with ARCO in positions ranging from president of ARCO's Exploration and Production Research and Technology Center to president of ARCO Alaska, Inc. Thompson also worked as an ARCO executive vice president, responsible for the company's global natural gas marketing and gas operating companies in Alaska, California, Indonesia, China, Singapore, Malaysia and Thailand.

Thompson sits on the boards of Alaska Airlines and Alaska Air Group. He is involved in community service through organizations such as United Way and the Anchorage Museum Foundation. He serves on the Board of Trustees for Alaska Pacific University.



Peg Tileston
Peg Tileston is president of Tileston and Associates, an Anchorage research and information retrieval business. Tileston is also chair and co-founder of Alaska Common Ground, an organization seeking consensus on public policy issues in Alaska. She is a board member of the Alaska Conservation Foundation and was appointed to the Governor's Alaska Oil and Gas Policy Council in 1996.

Tileston served 15 years on the Alaska Water Resources Board and 10 years on the Chugach Electric Association Board. She was the co-founder of Trustees for Alaska, an environmental public interest law organization.

Tileston is a graduate of Earlham College. She has been widely recognized for her community involvement and was named a woman of achievement by the YWCA in 1997.

Council Members



Al Adams
Al Adams served nine years in the Alaska State House of Representatives and 10 years in the Alaska State Senate. His distinguished legislative career included eight years as chair of the House Finance Committee and six years on the Senate Finance Committee. Adams retired from legislative service in 2001 and is currently the manager of economic development for the North Slope Borough mayor's office.

Adams' business experience includes serving as president of Kikiktagruk Inupiat Corporation and executive vice president of Nana Regional Corporation. He also served on the Alaska Native Claims Appeals Board.

Adams, a life-long Alaskan born in Kotzebue, graduated from Mt. Edgecumbe High School and the University of Alaska, Fairbanks.



Jacob Adams
Jacob Adams has been the president of Arctic Slope Regional Corporation (ASRC) since 1983. As president, Adams has led the corporation through a period of intensive diversification and remarkable growth.

Adams began his career with ASRC in 1971 when he was elected to the company's first Board of Directors. He has served on the board ever since.

When he was only 21, Adams won election to the Barrow City Council. When the North Slope Borough was organized in 1972, he was elected to its first assembly. Adams was later appointed to succeed the late Eben Hopson as mayor. Adams served on the assembly until 2000.

Adams, a successful whaling captain, helped form the Alaska Eskimo Whaling Commission.



George Ahmaogak, Sr.
George Ahmaogak, Sr. is currently serving his fourth term as North Slope Borough mayor. He first held the office from 1984-1990 and was elected again in 1993. During his tenure as mayor, Ahmaogak has spearheaded a variety of innovative initiatives including the Mayor's Jobs Program which provides employment opportunities to local Barrow residents while allowing them to maintain their subsistence lifestyle.

Prior to his first term as mayor, Ahmaogak was president of the Ukpeagvik Inupiat Corporation, the village corporation for Barrow. He has also served as the head of Piquniq Management Corporation. Later Ahmaogak was elected to the board of Arctic Slope Regional Corporation.

Ahmaogak is a successful whaling captain and a graduate of Mt. Edgecumbe High School in Sitka.



Rhonda Boyles
Rhonda Boyles was elected Fairbanks North Star Borough mayor in October 2000. A businesswoman and restaurateur, Boyles has been a leader in the Fairbanks community for over 25 years.

Boyles has served as director of the Greater Fairbanks Chamber of Commerce and sat on the Board of Directors of the Alaska State Chamber of Commerce. Her service has been honored by the University of Alaska, Fairbanks, who named her business leader of the year in 1999.

Throughout her career Boyles has taken a special interest in higher education, serving on a variety of boards including the University of Alaska College of Fellows, the University of Alaska Statewide Vocational and Technical Education Advisory Council and the Tanana Valley Campus Council.



Brian Davies
Brian Davies was involved with BP's development and operation of the North Slope oil fields, particularly Prudhoe Bay, for almost 23 years. Before coming to Alaska in 1971, Davies worked as a geologist and a petroleum engineer in the Southern North Sea, Abu Dhabi and Colombia.

Davies retired from BP in 1994 and is currently a part-time consultant. He is also involved with several Anchorage nonprofit organizations including the Anchorage Symphony Orchestra, Anchorage Museum, Alaska World Affairs Council and The Nature Conservancy of Alaska.

Davies grew up in Herefordshire, England and went to Trinity College, Dublin where he graduated with a degree in geology.



Ronald Duncan

Ronald Duncan is a founding member of GCI and has been the company's president and CEO since 1989. Duncan is a board member and past chairman of the Anchorage Economic Development Corporation and is current chairman of the Alaska Science and Technology Foundation. Prior to starting GCI, Duncan founded Alaskavision, an Alaska-based cable television company, and was a partner at Lyall Associates, a management and economic consulting firm. He has also served as an assistant director at the Johns Hopkins University Center for Metropolitan Planning and Research and as a special assistant to Congressman John Dow.

Duncan received a bachelor's degree in economics from Johns Hopkins University and a master's of business administration from Harvard Business School.



Jeffrey Feldman

Jeffrey Feldman is a partner in the Anchorage law firm Feldman and Orlansky. Prior to entering private practice, Feldman served as an assistant public defender for the Alaska Public Defender Agency and as a law clerk to Justice Edmond Burke of the Alaska Supreme Court.

Feldman has held a variety of professional appointments, including chairman of the Alaska Commission on Judicial Conduct and member of the Governor's Task Force on Civil Liability Reform.

Feldman obtained a B.A. and a J.D. degree from Northeastern University. In 1998, Feldman was awarded the Alaska Bar Association Professionalism Award and he twice received the United States District Court for the District of Alaska Public Service Award. In 1993, he received the ACLU Public Service Award.



Lee Gorsuch

Lee Gorsuch has been chancellor of the University of Alaska Anchorage since 1994. As chancellor, he oversees five colleges and schools on the Anchorage campus, the extended college campuses and the statewide delivery of education programs to the military.

From 1976 to 1994, Gorsuch led the Institute of Social and Economic Research (ISER). Later he served as the dean of the School of Public Affairs at UAA.

Gorsuch earned his undergraduate and graduate degrees in economics and community development from the University of Missouri at Columbia. He is a former president of both the Anchorage School Board and the Alaska Association of School Boards. Currently he serves on the board of Commonwealth North and the Nature Conservancy of Alaska.



Jerry Hood

As the leader of Alaska's Teamsters Union, Jerry Hood administers the collective bargaining needs of some 7,000 Alaskans. He was named secretary-treasurer of Teamsters Local 959 in February 1994 and has been elected to that position three times. Hood chairs the Union's Executive Board, the Alaska Teamster-Employer Welfare Trust and the Alaska Teamster-Employer Pension Trust. Hood also serves as special assistant on energy to the General President of the International Brotherhood of Teamsters James P. Hoffa.

Hood, who has long been active in civic and community affairs, is a member of the Anchorage Chamber of Commerce, Commonwealth North and the Resource Development Council. He also serves on the Board of Directors and Executive Committee of Arctic Power.



Jim Jansen
Jim Jansen is the president and CEO of Lynden Inc., an Alaskan transportation company.

Raised in the town of Lynden, Washington, Jansen grew up in the trucking and construction business. He served as a heavy equipment operator in the Navy and completed a tour of duty in Vietnam. Jansen came to Alaska in 1967 and worked hauling copper ore at Kennicott. Jansen joined Lynden full time in 1970, becoming president and CEO in 1983.

Jansen holds a degree in business administration from Central Washington College. He is a 12,000 hour commercial pilot, an assistant hunting guide and avid fisherman. He serves as a director of Wells Fargo Bank and is a past board member of the Special Olympics World Winter Games.



Carl Marrs
Carl Marrs has been with CIRI for more than 28 years, serving in a variety of positions before becoming president and CEO. A respected Alaska business leader, Marrs has repeatedly been named one of the top 25 most powerful Alaskans by the Alaska Journal of Commerce. He was also recently given the 2001 Alaska Federation of Natives Citizen of the Year Award.

Marrs currently sits on the boards of the Fiscal Policy Council of Alaska, Alaska Railroad Corporation, and Alaska Communications Systems Group, Inc. He is the president of the Association of ANCSA Regional Corporations Presidents/CEOs, Inc., a member of the Alaska SeaLife Center Board of Governors, a trustee of Alaska Pacific University and a member of the Anchorage Daily News Board of Advisors.



Mike O'Connor
Mike O'Connor has over 25 years management experience in oil and gas related construction projects. He is president of Peak Oilfield Service Company, an Alaskan-based general contractor that specializes in oilfield construction, rig moves, pipe fabrication, heavy hauling and equipment maintenance. O'Connor also oversees Precision Power Company and Peak's other subsidiaries.

O'Connor is active in the community, serving as a campaign coordinator for the United Way of Anchorage and a board member of the Alaska Support Industry Alliance. He has also volunteered for the Alaska Special Olympics and the 2001 World Winter Games.

O'Connor holds a bachelor's degree in civil engineering from Ohio State University and is a certified professional engineer.



Bob Penney
Bob Penney is the owner of Penco Properties, an Anchorage-based real estate brokerage company specializing in real estate development and property management. His development experience includes single and multi-family residential projects, commercial properties, retail buildings and land development in five western states.

Penney has a long history of community involvement in Alaska. His service has included work with the Anchorage Economic Development Corporation and Alaska Regional Hospital Board of Trustees. Penney is a past president of the Anchorage Chamber of Commerce and helped found the Resource Development Council.

A lifelong sport fisherman, Penney is the founder of the Kenai River Sportfishing Association and the Kenai River Classic. He was recently appointed to the North Pacific Fisheries Management Council.



Edward Rasmuson

Edward Rasmuson is a third generation Alaskan who began his career at National Bank of Alaska in 1956 as a summer employee. After graduating from Harvard University, he joined the bank full time and achieved successive promotions as the manager of several branches and later vice president. In 1974 he became president and in 1985 was appointed chairman of the board. Currently he is chairman of Wells Fargo Bank Alaska.

Rasmuson was a member of the University of Alaska Board of Regents for 14 years and is a past president of the Rotary Club and the Boy Scouts of Alaska, Western Council. He currently serves on committees at the University of Alaska Foundation, Alaska Pacific University and Providence Hospital.



Jack Roderick

Jack Roderick has had a long and varied career as a resource developer, public policy maker and writer. A resident of Alaska since before statehood, Roderick founded many small oil and resource-related businesses, including Alaska Exploration Corporation, Petroleum Publications and Alaska Industry magazine. As a consultant to Alyeska Pipeline Services Company during the early 1970s, Roderick assisted the company in settling Native land claims. Roderick was Greater Anchorage Borough mayor from 1972 to 1975 and later was deputy commissioner of the Alaska Department of Natural Resources.

A graduate of Yale University, Roderick also received an M.A. from Harvard University and a J.D. from the University of Washington. His book, *Crude Dreams: Oil and Politics in Alaska,* was published by Epicenter Press.



Dave Rose

Dave Rose is chairman and founder of Alaska Permanent Capital Management Company, the first major money management firm in Alaska designed to serve Alaska institutional investors. Before forming his own firm, Rose served ten years as the first executive director of the Alaska Permanent Fund Corporation. His professional career also includes leading the Alaska Municipal Bond Bank and revitalizing the Alaska Industrial Development and Export Authority.

Rose was the first chairman of the Anchorage Municipal Assembly and has received numerous awards for his dedication to public service. He currently serves as vice chair of the Alaska Pacific University Foundation and as a member of the Anchorage Concert Association Endowment. Rose earned an accounting degree from Queens College and an MBA from Syracuse University.



Jonathan Rubini

Jonathan Rubini is the managing partner of Foster Pepper Rubini & Reeves LLC, an Alaska law firm. He focuses his practice on public finance and general corporate law. Rubini is also currently chairman and chief executive officer of JL Properties, Inc., an Anchorage-based real estate development and management firm.

Rubini's past professional experience includes working as a partner with the firm Birch, Horton, Bittner & Cherot. He also served as a law clerk to Justice Allen T. Compton of the Alaska Supreme Court and as an assistant attorney general for the State of Alaska.

Rubini earned a B.A. from Brown University and a J.D. from Boalt Hall School of Law, University of California, Berkeley.



Grace Schaible
Grace Schaible is a retired attorney and a respected civic leader. During her time in private practice, Schaible was known for accepting pro bono cases. In 1987, she became the first woman to hold the office of Alaska Attorney General.

Schaible is a past chair of the Alaska Permanent Fund Corporation Board of Trustees and a former member of the University of Alaska Board of Regents. She has served on the Fairbanks Chamber of Commerce Board and as president of the University of Alaska Foundation. In 2000, Schaible was honored by the State Chamber of Commerce for her life-long contributions to Alaska.

Schaible graduated from the University of Alaska Fairbanks and earned a law degree from Yale University.



George Wuerch
George Wuerch was elected mayor of Anchorage in May 2000. Prior to taking office, he served on the Anchorage Municipal Assembly for five years.

Wuerch served as an officer in the U.S. Marine Corps for 20 years. After retiring from the Marines he became manager of governmental affairs for the Northwest Alaskan Gasline. In 1984 he moved to Alaska to become founder and president of Fluor Daniel Alaska Engineering. Later he joined Alyeska Pipeline Service Company as a vice president.

Wuerch holds a degree in engineering technology from Oregon State University and a master's degree from the U.S. Naval Postgraduate School. His community involvement has included service as chairman of the Anchorage Chamber of Commerce and chairman of the United Way Campaign.



Esther Wunnicke
Attorney Esther Wunnicke began her distinguished career in public service as an assistant attorney general for the State of Alaska. In 1983, Wunnicke was appointed commissioner of the Department of Natural Resources. Wunnicke's federal service in Alaska has included work with the Federal Field Committee, the Federal-State Land Use Planning Commission and the Department of Interior Mineral Management Service.

Since retiring from the Department of Natural Resources in 1986, Wunnicke has served on the State Commission on Human Rights, the Oil and Gas Policy Council and the Alaska Rural Governance and Empowerment Commission.

In 1991 Wunnicke and a group of citizens formed Alaska Common Ground, a forum for Alaska citizens to address long-term public policy issues.

Ex-Officio Members of the Alaska Highway Natural Gas Policy Council

Fran Ulmer, Lieutenant Governor, State of Alaska
Rick Halford, President, Alaska State Senate
Brian Porter, Speaker, Alaska State House of Representatives
Georgianna Lincoln, Senator, Alaska State Senate
Ethan Berkowitz, Minority Leader, Alaska State House of Representatives
Bruce Botelho, Attorney General, Department of Law
Michele Brown, Commissioner, Department of Environmental Conservation
Wilson Condon, Commissioner, Department of Revenue
Ed Flanagan, Commissioner, Department of Labor and Workforce Development
Patrick Galvin, Director, Division of Governmental Coordination
John Katz, Director of State/Federal Relations, Office of the Governor
Joseph Perkins, Commissioner, Department of Transportation and Public Facilities
Pat Pourchot, Commissioner, Department of Natural Resources
Frank Rue, Commissioner, Department of Fish and Game
Deborah Sedwick, Commissioner, Department of Community and Economic Development

Staff to the Council:
Ken Freeman, Executive Director
Debra Ceffalio, Communications Coordinator
Erika McConnell, Project Assistant







From top: Barrow dancers welcome the Council to the North Slope; the Council staff reviews final meeting documents; Co-chairs Jim Sampson and Frank Brown participate in the Fairbanks hearing with Governor Knowles.

From the Co-Chairs

Dear Alaskan,

It has been an honor to co-chair the Alaska Highway Natural Gas Policy Council, a diverse group of distinguished and knowledgeable Alaskans. All 28 Council members deserve recognition for the long hours and hard work they dedicated to this effort.

We would like to thank Governor Knowles for the opportunity to serve on this Council. By giving Alaskans a meaningful opportunity to discuss the issues surrounding natural gas development, the Council has helped create a growing momentum and excitement for an Alaska gasline project.

We were impressed with the thoughtful testimony we received from the many Alaskans, project proponents and industry experts who made presentations to our group. Alaska is fortunate to have so many knowledgeable people working to develop our natural gas resources. We'd also like to thank the mayors, civic leaders and others who so graciously welcomed the Gas Policy Council into their communities.

Finally, we'd like to thank the staff of the Governor's office and other departments for their work, as well as the many legislators who worked with us along the way. A special thank you to Lieutenant Governor Ulmer and members of the Governor's Gas Cabinet for their dedication to this project.

One key theme emerged during our work – the importance of unity. Alaskans prosper when Alaskans work together. We urge the Administration, Legislature and congressional delegation to continue to work together to ensure that Alaska's needs are put first as we develop our gas resources.

Sincerely,

Frank Brown
Co-Chair

Jim Sampson
Co-Chair



In Memoriam

Rosemarie Maher, 1947-2001

In July, the Council mourned the passing of Council member Rosemarie Maher, a beloved friend and respected colleague.

Rosemarie was the president and chief executive officer of Doyon Ltd. Maher had served on the board of the Interior Native corporation from 1979 until she was named president in January 2000. She replaced Morris Thompson who retired from Doyon in December 1999. She also served as co-chair of the Alaska Federation of Natives from 1997-2000 and on the Alaska Board of Game during the late 1980s and early 1990s.

Maher was born in a canvas tent at a fish camp on the Nabesna River in 1947. She grew up in Northway and learned the traditions of the Upper Tanana Athabaskans. Maher is remembered as a woman who could move easily between the corporate and village life. She was a respected leader who cared deeply for the people she served. She will be missed by many in Alaska.

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Alaska Natural Gas In-State Demand Study
ASP 2001-1000-2650

Prepared on Behalf of the Alaska Department of Natural Resources

Volume 1: Technical Report

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Executive Summary

The purpose of this report is to examine the future natural gas demand of Alaska communities and businesses. The study was prepared in a manner that provides quantitative information about natural gas usage to assist the Alaska Department of Natural Resources, as well as other important stakeholder groups, in evaluating the possibilities of meeting certain Alaska energy needs through Alaska North Slope (ANS) gas. The major results of our study can be summarized as follows.

- We developed a baseline forecast which assumes a business as usual environment over the forecast period. Alaska prices were assumed to be constant, in real dollars, over the forecast period, while income was assumed to be increasing at a real annual average rate of a half-percent per year. (Chapter 4, page 25)

- Baseline residential natural gas demand is expected to grow at an average rate of 1.8 percent per year to 2020. Over the next ten years, residential baseline demand will increase by 3.5 Bcf per year, and will increase by 7.9 Bcf by 2020. (Chapter 4, Table 4.1)

- Baseline commercial natural gas demand is expected to grow at an annual average rate of 1 percent per year to 2020. Over the next ten years, commercial baseline demand will increase by 3.3 Bcf, and will increase by 6.3 Bcf by 2020. (Chapter 4, Table 4.2)

- The baseline forecast estimates moderate to flat growth of industrial natural gas usage. Over the forecast period, industrial baseline demand will increase at an annual average rate of approximately half a percent. Industrial demand will increase by 4.0 Bcf by the year 2010, and by 8.0 Bcf by 2020. (Chapter 4, Table 4.3)

- Electric utility demand for natural gas will increase by 0.7 percent per year to 2020. Electric utility demand will increase by 1.4 Bcf by the year 2010, and by 5.1 Bcf by 2020. (Chapter 4, Table 4.4)

- Total baseline natural gas usage is forecasted to grow at an annual average rate of little under one percent. Residential customers will account for 28.5 percent of this growth, commercial customers will account for 22.7 percent of this growth, industrial customers will account for 28.9 percent of this growth, and electricity utilities will account for 19 percent of this growth. (Chapter 4, Table 4.5)

Summary of Baseline Forecast

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,518,229	28,566,567	73,238,676	35,656,886	154,980,358
2005	19,198,104	30,564,363	75,226,290	35,406,497	160,395,253
2010	21,059,031	31,851,818	77,214,690	37,031,714	166,836,744
2015	23,121,582	33,362,837	79,203,895	38,899,627	174,587,941
2020	25,409,386	34,837,741	81,193,900	40,790,982	182,232,010
10 Year Increase	3,540,802	2,964,742	3,976,015	1,374,828	11,856,386
20 Year Increase	7,891,157	6,271,174	7,955,225	5,134,096	27,251,652

Note: Baseline forecast excludes natural gas dispositions to the Kenai LNG Plant. See discussion in Chapters 2 and 7.

- The baseline forecast developed in this study was subjected to a number of sensitivity analyses to determine the impact of changes in economic assumptions on natural gas usage. (Chapter 5, page 37)

- Under the high price/high income scenario, prices and income were expected to increase at a rate of one percent per year in real dollars. Under the low price scenario, prices were assumed to decrease at a real rate of one percent per year. Under the low income scenario, income was assumed to be constant in real dollars over the forecast period. (Chapter 5, page 37)

- Changes in price assumptions had larger influences on the baseline forecast than changes in income assumptions. (Chapter 5, Figure 5.2)

- Under a low price forecast, total in-state natural gas usage would grow at a 0.05 percent rate higher than under the baseline forecast. The low price forecast assumes that prices will fall by an annual rate of one percent during the forecast period. The baseline forecast, on the other hand, assumes constant prices. (Chapter 5, Figure 5.1)

Summary of Forecast Sensitivities

High Price Forecast Summary

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,500,093	28,451,442	73,197,507	35,569,901	154,718,943
2005	19,035,431	29,336,492	74,978,844	34,521,334	157,872,101
2010	20,735,890	29,585,393	76,760,215	36,105,921	163,187,419
2015	22,620,716	30,107,039	78,541,636	37,927,136	169,196,528
2020	24,712,105	30,663,720	80,323,106	39,771,208	175,470,138
10 Year Increase	3,235,797	1,133,951	3,562,708	536,020	8,468,477
20 Year Increase	7,212,012	2,212,278	7,125,599	4,201,307	20,751,195

High Income Forecast Summary

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,584,947	28,576,984	73,271,847	35,569,901	155,003,678
2005	19,631,736	30,629,414	75,426,724	38,947,146	164,635,020
2010	21,920,440	31,970,191	77,584,783	40,734,885	172,210,299
2015	24,479,334	33,536,403	79,746,048	42,789,590	180,551,375
2020	27,340,683	35,066,944	81,910,542	44,870,081	189,188,250
10 Year Increase	4,335,493	3,393,207	4,312,935	5,164,984	17,206,621
20 Year Increase	9,755,736	6,489,961	8,638,695	9,300,180	34,184,572

Low Price Forecast Summary

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,536,585	28,683,799	73,280,303	35,569,901	155,070,588
2005	19,365,289	31,915,682	75,477,994	36,291,659	163,050,624
2010	21,396,261	34,555,030	77,679,715	37,957,507	171,588,512
2015	23,652,356	37,571,398	79,885,529	39,872,118	180,981,401
2020	26,159,711	40,685,286	82,095,472	41,810,757	190,751,225
10 Year Increase	3,859,676	5,871,231	4,399,411	2,387,606	16,517,924
20 Year Increase	8,623,126	12,001,487	8,815,169	6,240,856	35,680,637

Low Income Forecast Summary

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,451,674	28,532,498	73,205,369	35,569,901	154,759,441
2005	18,781,361	30,387,626	75,025,986	31,865,847	156,060,819
2010	20,261,517	31,807,560	76,846,603	33,328,543	162,244,222
2015	21,910,548	33,225,744	78,667,220	35,009,664	168,813,176
2020	23,749,813	34,635,893	80,487,837	36,711,884	175,585,427
10 Year Increase	2,809,844	3,275,062	3,641,234	-2,241,358	7,484,781
20 Year Increase	6,298,140	6,103,395	7,282,468	1,141,983	20,825,986

- After examining a range of expanded service opportunities through the state, the largest concentrations of new service opportunities are in the South Central and Interior regions of the state. There are approximately 2.2 Bcf of expanded service opportunities in South Central region and 4.3 Bcf of expanded service opportunities in the Interior. (Chapter 6, Table 6.6)

- There are opportunities for expanding natural gas usage by the addition of new industries. The two that were highlighted for investigation in this study included the addition of Internet server farms and a major petrochemical industry. Both are energy-intensive industries. (Chapter 7)

- It would take the addition of a relatively large Internet facility (i.e., about a one million square foot facility) to impact total in-state usage. We estimate that a high power density, million square foot server farm could use up to 4.3 Bcf per year. (Chapter 7, Table 7.1)

- A major petrochemical facility, on the other hand, could have a more meaningful impact. Based upon statistics from typical world class facilities on the Gulf of Mexico, a 619 ton per year ethylene facility could use as much as 27 Bcf per year. (Chapter 7, Table 7.3)

- All generating units in the state were examined to identify facilities those that could potentially shift their primary fuel to natural gas. Fuel oil and diesel facilities were the most attractive candidates. The highest concentration of these facilities were located in the Interior section of the state. There are approximately 200 MWs of capacity in this region that could shift from fuel oil to natural gas. Annual natural gas usage would be about 15 Bcf per year if all of the eligible facilities were to switch fuels. (Chapter 8, Tables 8.1 and 8.4)

- There is a supply side efficiency opportunity for new central station gas fired generation. The economics of a 250 MW combined cycle facility stack up favorably with the marginal costs of existing generating units. This new generation could account for about 12.5 Bcf of natural gas usage per year. However, prior studies of power markets performed on behalf of the Regulatory Commission of Alaska, have noted that Alaska does not have a potential capacity need until the year 2014. If a new generating unit were to be added prior to that time, older generation could be displaced. (Chapter 8, Tables 8.10 and 8.11)

- Supplying natural gas to concentrated opportunities for new in-state usage would require significant infrastructure investments. We examined a number of major concentrations of potential gas usage, and modeled the

typical costs of supplying natural gas to these potential applications. These results included:

- ***New Service to the Interior:*** Positive opportunities for natural gas service exist based on our initial analysis. This option warrants further study. Estimated household energy savings of shifting from fuel oil to natural gas were about 20 percent, while savings associated with shifting from electricity to natural gas were approximately 24 percent. (Chapter 9, page 120)

- ***Fuel Switching:*** Small, but positive economic opportunities for switching fuel oil fired power plants to natural gas in the Interior region. Net fuel savings ranged between a third to a fifth of a cent per kWh generated. (Chapter 9, page 124)

- ***Gas by Wire:*** There are competitive opportunities for new power generation. However, as noted earlier, the need for a major new power generation resource is questionable until the year 2014. (Chapter 9, page 128)

- ***Expanded Service to the Southcentral:*** Study results indicate that, in order to be competitive, spur line throughput must achieve volumes beyond levels that correspond to various individual and incremental gas usage applications considered in this study. Some portion of gas usage, 30-to-40 Bcf per year, currently supplied by producing fields in the Cook Inlet Basin would be required to generate sufficient economies of scale. The decline rates of existing Cook Inlet fields, combined with the steady progression of demand in the Southcentral and Interior regions suggest that, even with the near-term discovery of one Tcf of additional Cook Inlet reserves, a supply shortfall of 30-to-40 Bcf or more per year is likely to occur sometime between 2009 and 2015. Thus, a lateral spur pipeline that delivers gas into the Southcentral region could provide a long-term, economic solution to the supply-demand imbalance projected for this area. (Chapter 9, page 131)

CHAPTER 1: INTRODUCTION

1.1: Research Overview

The purpose of this report is to examine the future natural gas demand and supply for Alaska communities and businesses. The study was prepared in a manner that provides a host of quantitative information about natural gas usage to assist the Alaska Department of Natural Resources, as well as other important stakeholder groups, in evaluating the possibilities of meeting certain Alaska energy needs through Alaska North Slope (ANS) gas. Our study considers a number of opportunities including expanding natural gas service to retail customers, increased gas-fired power generation alternatives, and the addition of new industries to the Alaska economy.

A number of demand models have been developed throughout the course of this report. The primary set of models estimate customer class specific natural gas usage. These models have been developed to understand the important empirical determinants of natural gas demand, as well as forecasting potential in-state usage under a number of different economic scenarios.

The report uses a geographic information system (GIS) approach for identifying new regional sources of natural gas usage. Our GIS model identifies existing and potential sources of natural gas usage, and maps those locations to existing and future infrastructure development. Volumes by location and region are developed from this approach. Throughout the course of our report, we will define Alaska regions as identified below in Figure 1.1. These regions include: the Far North, the Interior, the Southwest, the Southcentral, and the South Eastern portions of the state.

Our GIS analysis was comprised of two approaches. First, we examine total regional in-state possibilities for expanded natural gas service regardless of distance and economics. This approach essentially defines the outer boundary of potential new natural gas usage in the state. Second, we examine the possibilities of expanding natural gas service within two major natural gas infrastructure systems: the existing local distribution networks in place in Alaska, and the proposed Alaska Highway Route (AHR).



Figure 1.1: Definition of Alaska Regions

We also examine the possibilities of new sources of natural gas usage. These include new natural gas power generation possibilities as well as a number of new commercial and industrial opportunities. The power generation options we consider can be broken into two classes. First, we estimate the opportunities for fuel switching at existing utility and non-utility fuel oil and diesel fired generation facilities. Second, we examine the possibilities of a "gas-by-wire" application where a larger central station power generation facility is located in close proximity to the AHR. Power generated from the gas-fired facility would then be moved by high voltage transmission lines to nearby communities.

We also analyze the possibilities of adding new energy intensive industries to the Alaska economy. These include: the development of an internet server farm; the possibilities of a new petrochemical facility in the state; as well as expansion of existing LNG and ammonia-urea production.

Lastly, no analysis of in-state demand would be complete without examining the cost implications of supplying natural gas to these identified possibilities. In a later chapter of our report, we examine the costs associated with stepping natural gas down from the high pressure AHR transmission line to potential regional natural gas usage applications.

1.2: Organization of Report

This report is organized into a total of ten chapters, three technical appendices, and a bibliography. The technical appendices and bibliography associated with this report are included in Volume 2.

The first chapter is this introduction that gives an overview of the report and its organization.

The second chapter of our report provides an overview of recent Alaska natural gas market trends. This chapter is a general overview over the past several years. A more detailed analysis, over a longer time period, can be found in Appendix 1 (Volume 2).

The third chapter of our report provides a general discussion of demand modeling and the techniques typically employed in this type of research. For those readers less interested in these technical details, this chapter of the report can be skipped without loss of context. For those readers looking for greater detail on natural gas demand modeling, Appendix 2 (Volume 2) has been provided for that purpose.

The fourth chapter of our report provides our baseline forecast of natural gas usage by major customer class: residential, commercial, industrial, and power generation. This chapter highlights the results of our forecast, with little discussion of our actual model and its statistical results. Those readers looking for greater empirical detail, in terms of the statistical models and their results, should refer to Appendix 3 (Volume 2).

The fifth chapter of our report subjects our baseline forecasts to a number of different assumptions about economic conditions in Alaska and how they could impact in-state natural gas usage.

The sixth chapter of our report examines new retail service opportunities for natural gas. This chapter highlights our GIS approach and maps out new usage opportunities on a regional and geographic proximity basis.

The seventh chapter of our report examines new natural gas opportunities through additions of new industries to the Alaska economy. This chapter provides some estimates of potential natural gas usage by the previously discussed internet server farm and the development of a new major petrochemical facility. We also consider expanded opportunities for natural gas usage at existing Alaska industries. In particular, expanded usage at existing LNG and urea production facilities.

The eighth chapter of our report examines new opportunities for natural gas fired power generation. This chapter identifies fuel switching applications, and

potential natural gas usage volumes that could result from a shift in primary fuel at certain power generation stations and locations. We also examine a gas-by-wire application in this chapter of our report.

The ninth chapter of our report examines the cost of supplying natural gas to a number of the opportunities identified in the earlier chapters of our report. Our primary emphasis has been on the new service opportunities in relatively concentrated areas, in addition to power generation applications.

The tenth chapter of our report presents our overall conclusions. Also included with this report, in Volume 2, is an exhaustive bibliography of the leading articles in natural gas industry supply and demand modeling.

CHAPTER 2: RECENT TRENDS IN ALASKA'S RETAIL NATURAL GAS MARKETS

This chapter of our report will examine some of the more recent trends associated with the major natural gas consuming sectors in Alaska. A more detailed, longer run historical analysis has been presented in Appendix 1.

2.1: Data Used in the Analysis of Alaska Natural Gas Usage

The following discussion, as well as the models that we will develop in subsequent chapters, utilizes data from the EIA 176 database published by the U.S. Department of Energy, Energy Information Administration (EIA). This database is developed and maintained from annual survey information collected by the EIA under EIA Form 176. All major interstate natural gas pipeline companies, intrastate natural gas pipeline companies, investor and municipally owned natural gas distributors, underground natural gas storage operators, synthetic natural gas plant operators, among other providers of natural gas service, are required to complete this form. The completion of this report is mandatory under the Federal Energy Administration Act of 1974.

For a typical LDC, the EIA Form 176 requirements include annual reporting on the disposition of all gas flows over the company's system. This includes accounting for all gas sales, prices (average revenues), and customers for residential, commercial, industrial, and any other retail customer class. In addition, LDCs must report any transportation services (and volumes) for non-core customers. Thus, if a commercial or industrial customer is within the city gate, but receives gas from a third party, the LDC is required to report the volumes it transports to these customers even though the LDC is only providing transportation services.

In the information reported for Alaska natural gas companies, two LDCs filed information on sales, customers, and transportation volumes. The majority of their disposition was associated with traditional retail sales (i.e., residential, commercial, industrial, etc.). However, starting in 1992, Enstar began reporting transportation volumes for one industrial customer.[1] In 1995, the Company began reporting transportation volumes for commercial customers as well. Since 1995, the number of non-core commercial customers for Enstar has grown significantly. In 1995, there were 62 commercial customers receiving transportation service only from Enstar. This increased to 187 in 1996; 401 in 1997; and 768 in 1998. By 1999, this number has grown to 883 commercial customers taking only transportation service.

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[1] In such a situation, if an LDC is transporting gas on behalf of a customer within the city gate, then that customer is being served by a competitive third party, presumable a competitive retail natural gas marketer. Thus, identifying transportation customers within an LDC's service can give some indication of the degree of competition within that particular area.

Other companies with pipeline assets are also required to report transportation and sales volumes even if they are not an LDC. According to the data included in the EIA 176 database, there were 6 non-LDCs reporting either transportation and/or direct sales. These included Arco Alaska, Inc., Chevron USA, Marathon Oil Company, Phillips Alaska Natural Gas Company, Ukpeaqvik Artic Slope, and Union Oil Company of California (UNOCAL). In 1999, these companies, collectively, served 11 commercial customers, of which 2 were transportation customers alone. In the same year, these companies collectively served 9 industrial customers. Enstar provided transportation service to three industrial customers.

The EIA database that we used in our historic trends analysis, as well as in the development of our forecasting models, excludes information from other natural gas uses that are reported separately to the DOE. These include field uses of natural gas in oil and gas production, internal company use of natural gas, pumping and compressor station use of natural gas, and liquefied natural gas (LNG). None of these gas usage activities are included in the commercial and industrial series analyzed in this chapter, nor were these natural gas uses included in commercial or industrial forecasting models. Gas Dispositions to the Kenai LNG Plant are excluded from the EIA data series because the LNG it is exported and not considered as an in-state requirement. However, the role of LNG in Southcentral Alaska is important since it accounts for close to 36 percent of total gas dispositions in the Cook Inlet area (see discussion in Chapters 7 and 9).

In addition to usage and price information included in the EIA Form 176, we compiled additional information to supplement the data we would use to specify our demand equation. This includes energy price information for alternative fuels such as diesel, fuel oil, and electricity. This information was also collected from the US Department of Energy, and is published every year in the Annual Energy Report. We also collected employment and state gross product information from the US Department of Commerce, Bureau of Economic Analysis (BEA).

2.2: Recent Trends in Retail Natural Gas Prices

Over the past several years, most Alaska customer classes have experienced price decreases for natural gas service. These trends have been presented in Figure 2.1. In this figure, customer class retail prices are measured as average revenues (expressed in non-inflation adjusted, money-of-the-day dollars).

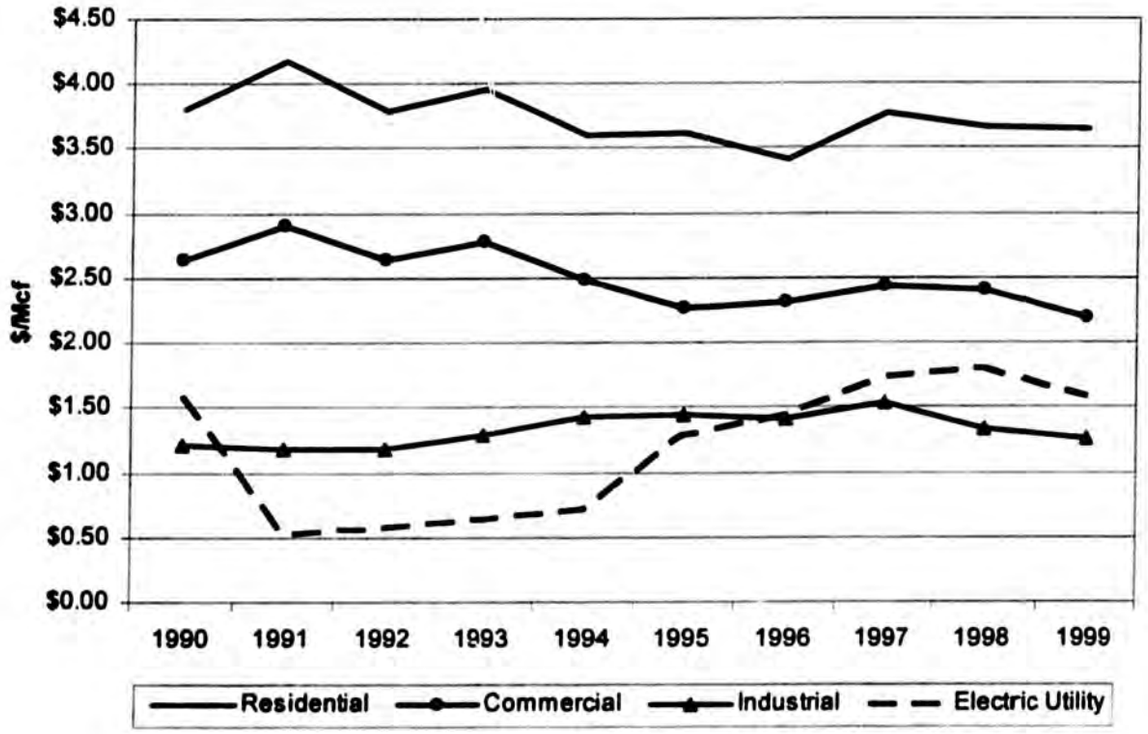

Figure 2.1: Recent Trends in Alaska Natural Gas Prices by Sector

Source: US Department of Energy, Energy Information Administration. *Natural Gas Annual*

As seen from the figure, residential rates tend to be the highest of all Alaska customer classes. Commercial rates are the next highest, with the differential between commercial and residential rates falling by close to 50 cents per Mcf over the past decade. Since 1990, the relative ranking of prices for electric utilities and industrial customers has shifted. Prior to 1996, electric utilities generally paid less on a Mcf basis for natural gas service than industrial customers. This changed in 1996, with electric utilities paying slightly higher rates. Since electric utilities in Alaska tend to sign longer term fuel agreements, this shift could reflect different contract terms and conditions.

Natural gas retail prices are usually composed of two parts: the base rate and the purchased gas acquisition (PGA) rate. The base rate covers the cost of providing service and return on, and of, investment for the local distribution company. The PGA, on the other hand, is the cost of obtaining natural gas, which is a pass-along to end-users. The different between the total retail rate and the PGA can be thought of as the cost of providing non-fuel related service. Figure 2.2 presents the relative changes of residential retail prices and PGA adjustments for Enstar, the state's largest natural gas local distribution company.

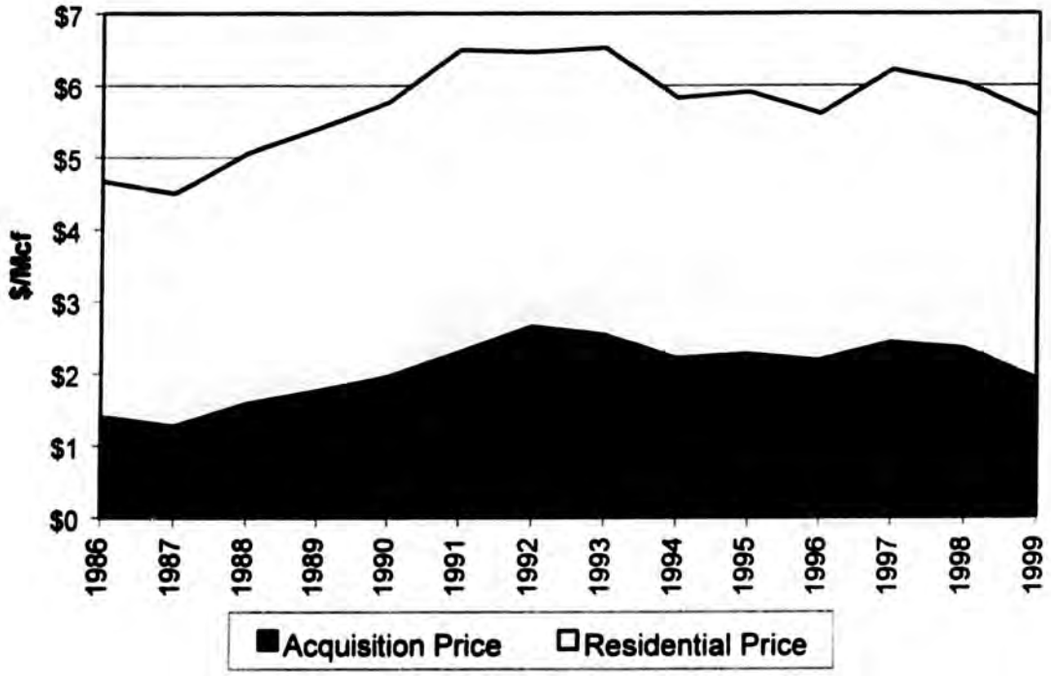

Figure 2.2: Residential Retail Rates and Gas Acquisition Costs -- Enstar

Source: U.S. Department of Energy, EIA Form 176.

As seen in Figure 2.2, retail prices have, in general, followed shifts in gas acquisition charges paid by LDCs. The lower area highlighted in the figure represents the acquisition cost of the LDC, while the higher area represents the total residential price. The difference between these two areas represents the non-fuel distribution charges associated with the residential rate, which has been relatively stable at an average of $1.50 per Mcf over the past five years.

A comparable analysis has been provided in Figure 2.3. This figure compares residential markups,[2] commercial markups, and the differentials between gas acquisition charges and wellhead prices. All three series tend to move in the same direction indicated that most of the recent trends in retail rates are driven by the cost of gas that is incurred by LDCs. The graph presented in Figure 2.3 compares relative price markups for Enstar.

[2]Residential mark-ups are defined as the residential retail price less the overall system gas acquisition cost. Commercial mark-ups are simply the commercial retail price less the same gas acquisition cost.

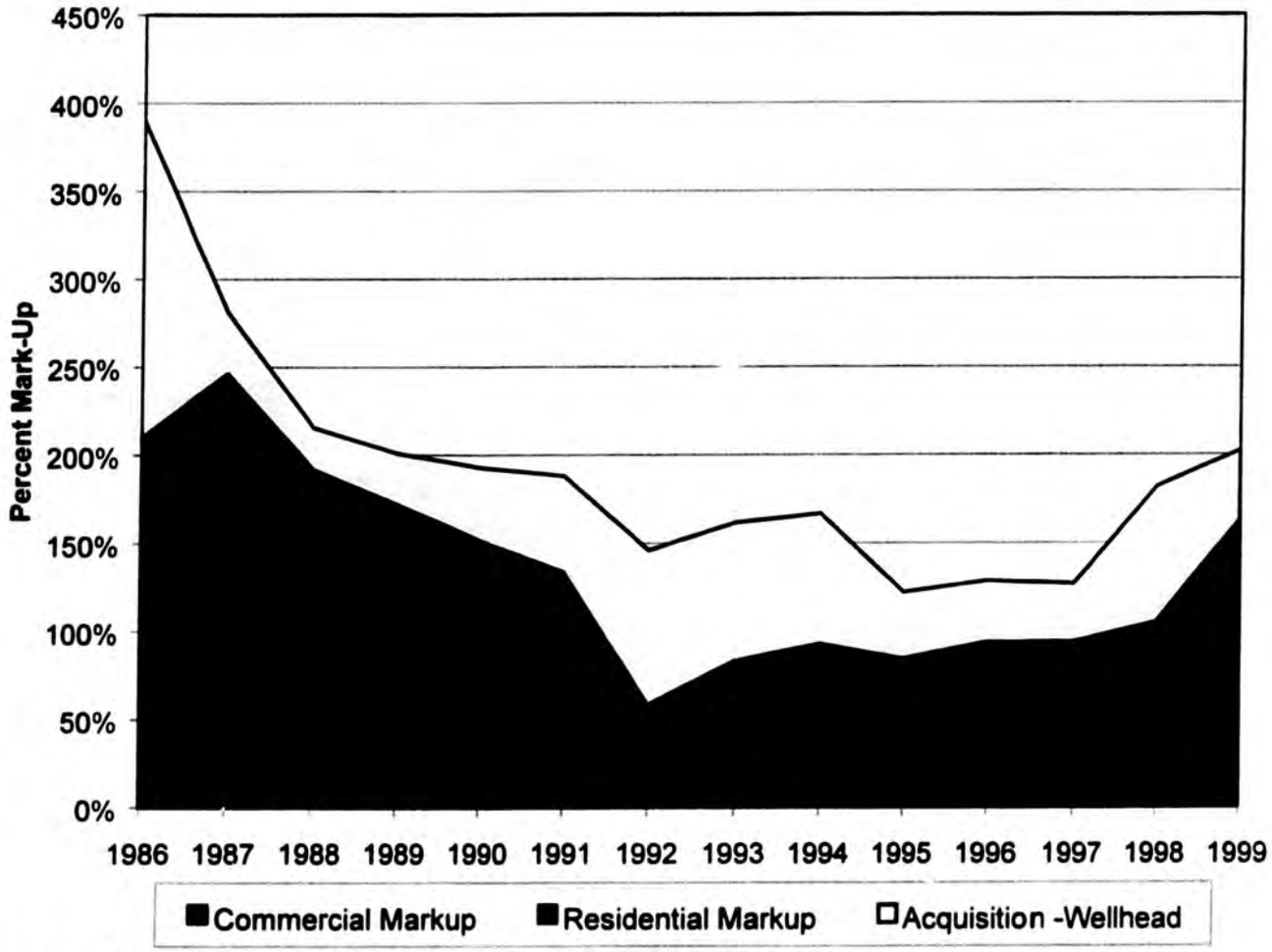

Figure 2.3: Comparison of Residential, Commercial, and Wellhead to PGA Markups – Enstar

Source: U.S. Department of Energy, EIA Form 176.

2.3: Recent Trends in Natural Gas Customer Growth

Over the past 10 years, residential natural gas customer growth has been relatively strong. Figure 2.4 presents annual number of residential and commercial customers while Figure 2.5 presents the annual number of industrial customers. Residential customer growth over the past decade has averaged at an annual rate of about 2.5 percent, while commercial customers have grown at an annual average rate of 1.3 percent. Industrial customer growth has been very limited, and over the past decade has hovered between 8 and 11 customers.

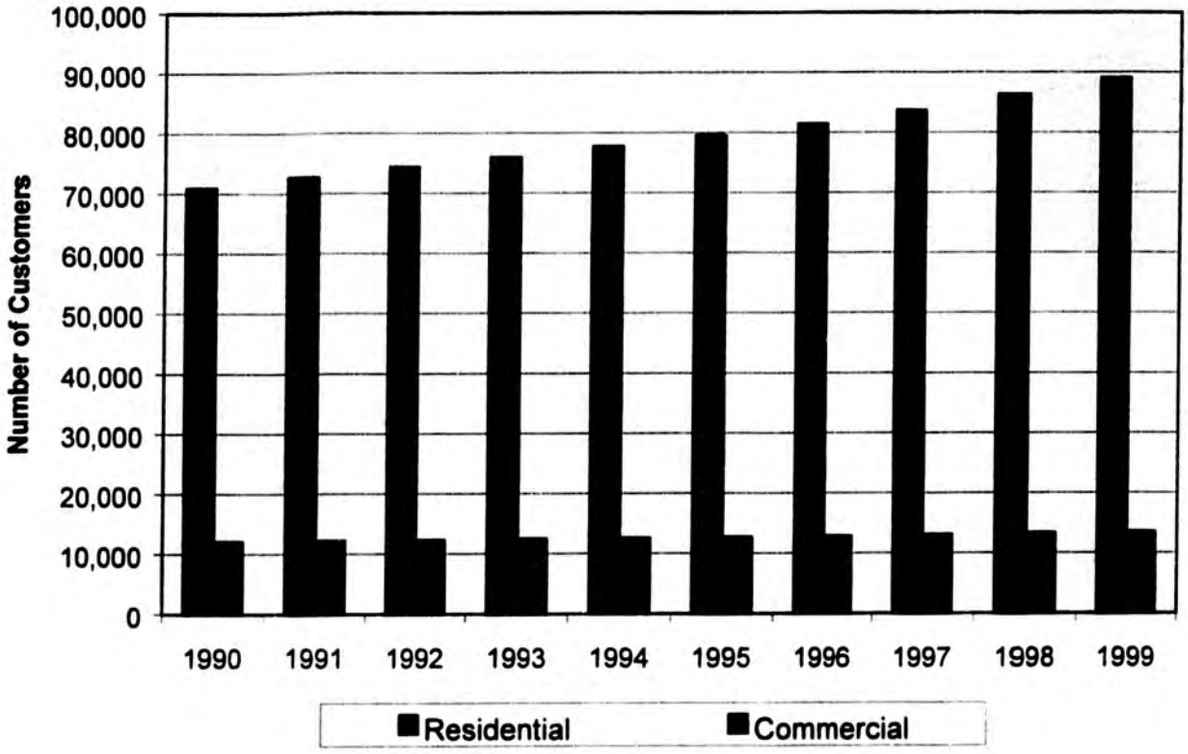

Figure 2.4: Annual Number of Residential and Commercial Customers

Source: US Department of Energy, Energy Information Administration. *Natural Gas Annual.*

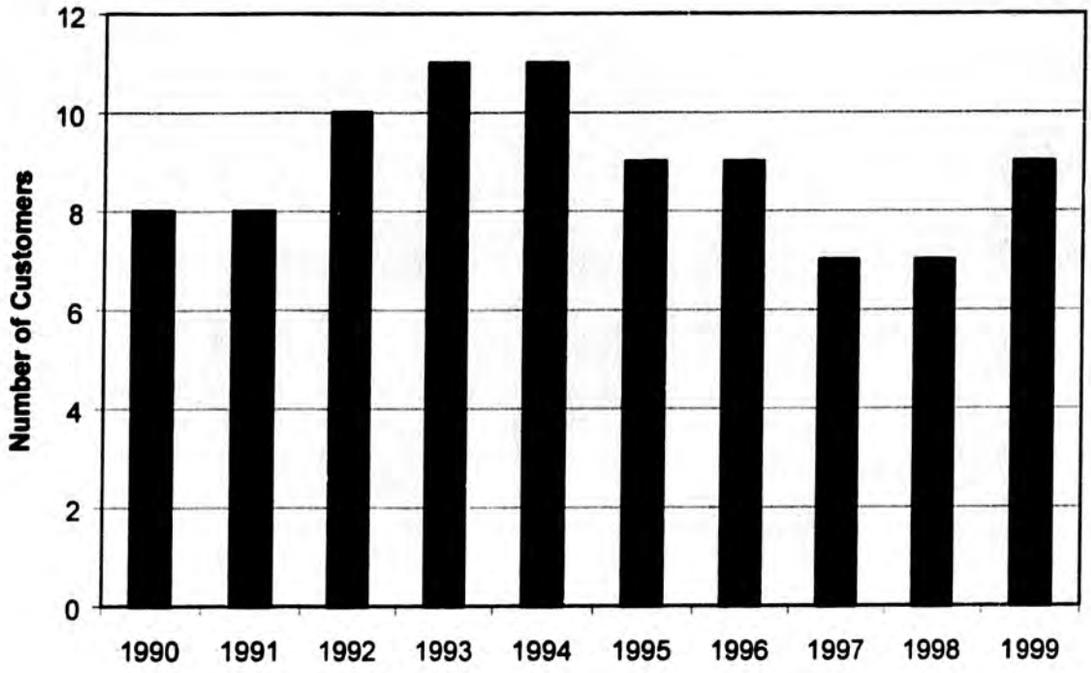

Figure 2.5: Annual Number of Industrial Customers

Source: US Department of Energy, Energy Information Administration. *Natural Gas Annual.*

2.4: Recent Trends in Natural Gas Usage

Industrial customers are the largest users of Alaska natural gas. Total industrial natural gas usage averaged around 73 Bcf annually during the past decade. Usage for these customers took a decided dip between 1996 and 1998, but has rebounded since that time. The same trend is noticeable for electric utility customers of natural gas who averaged about 30 Bcf per year over the past decade. Both customer classes have tended to have relatively flat usage growth throughout the 1990s.

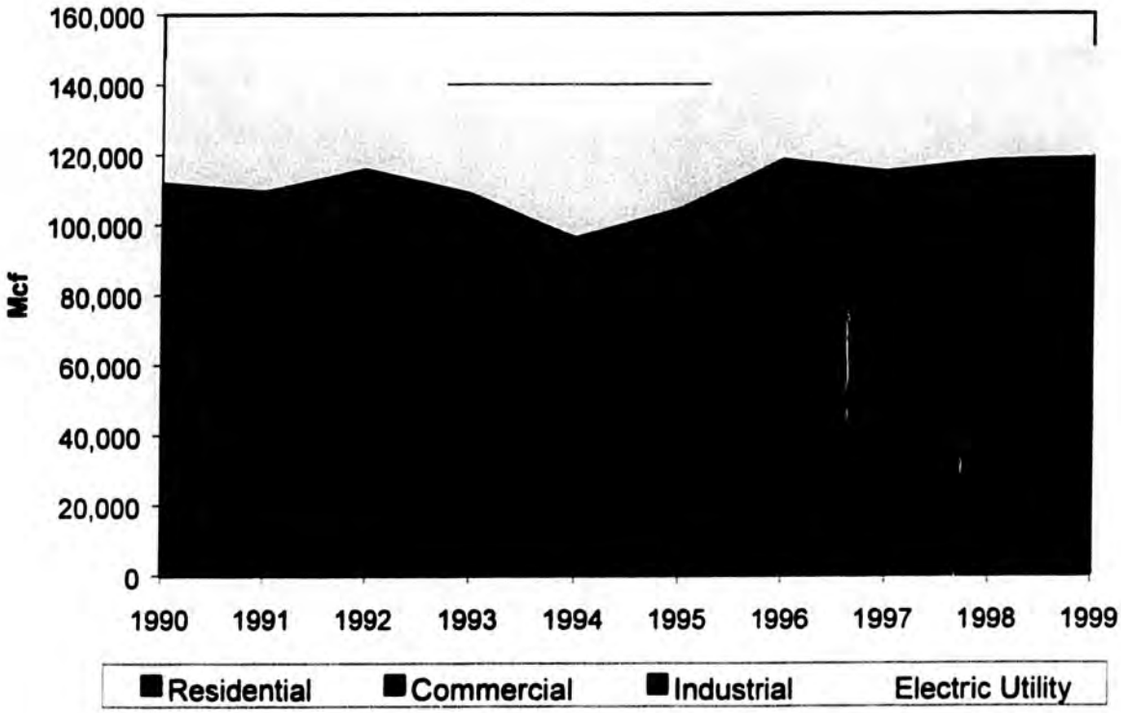

Figure 2.6: Recent Trends in Alaska Natural Gas Usage (Annual Mcf)

Source: US Department of Energy, Energy Information Administration. *Natural Gas Annual*

Residential and commercial customers, have both smaller, and more stable usage patterns than their larger industrial and electric utility counterparts. Over the past decade, residential usage has grown by an annual average rate of 2.8 percent, while commercial usage has grown by 2.7 percent over the same time period. In recent times, usage for residential customers has averaged around 15 Bcf per year, while commercial usage has averaged about 24 Bcf per year.

Figure 2.7 presents recent trends in residential average usage. As noted in earlier graphs, residential customer growth has been relatively steady and consistent over the past decade. Usage, on the other hand, has moved sporadically. In some years usage has been up dramatically, like the 12 percent increase in 1998-1999, while in other years it has fallen, like the 6.3 percent decrease in 1996-1997. As a consequence, average usage has tended to move in fits and spurts.

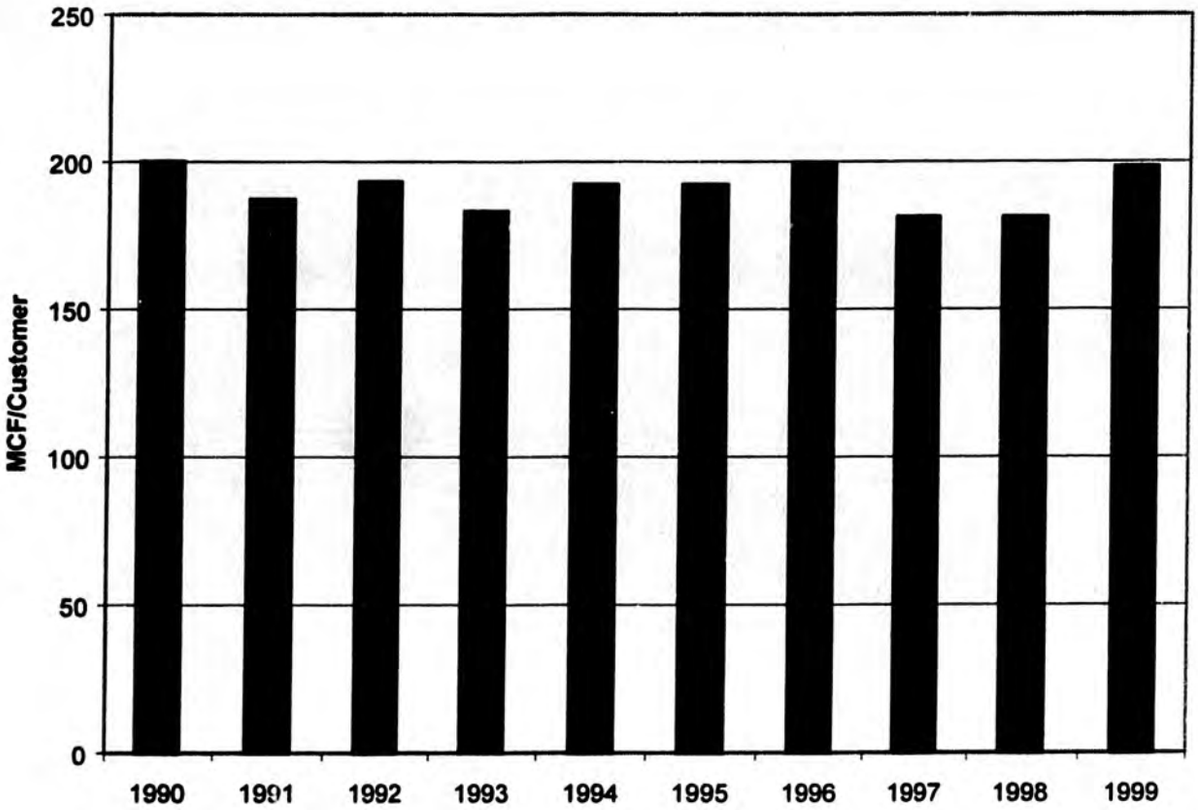

Figure 2.7: Residential Average Usage

Source: US Department of Energy, Energy Information Administration. *Natural Gas Annual*

Figure 2.8 presents average usage for commercial customers. Unlike the recent trends with residential customers, commercial customers have exhibit more stable average usage growth over the past decade. Average usage for commercial customers has grown at an average rate of about 1.4 percent over the past 10 years.

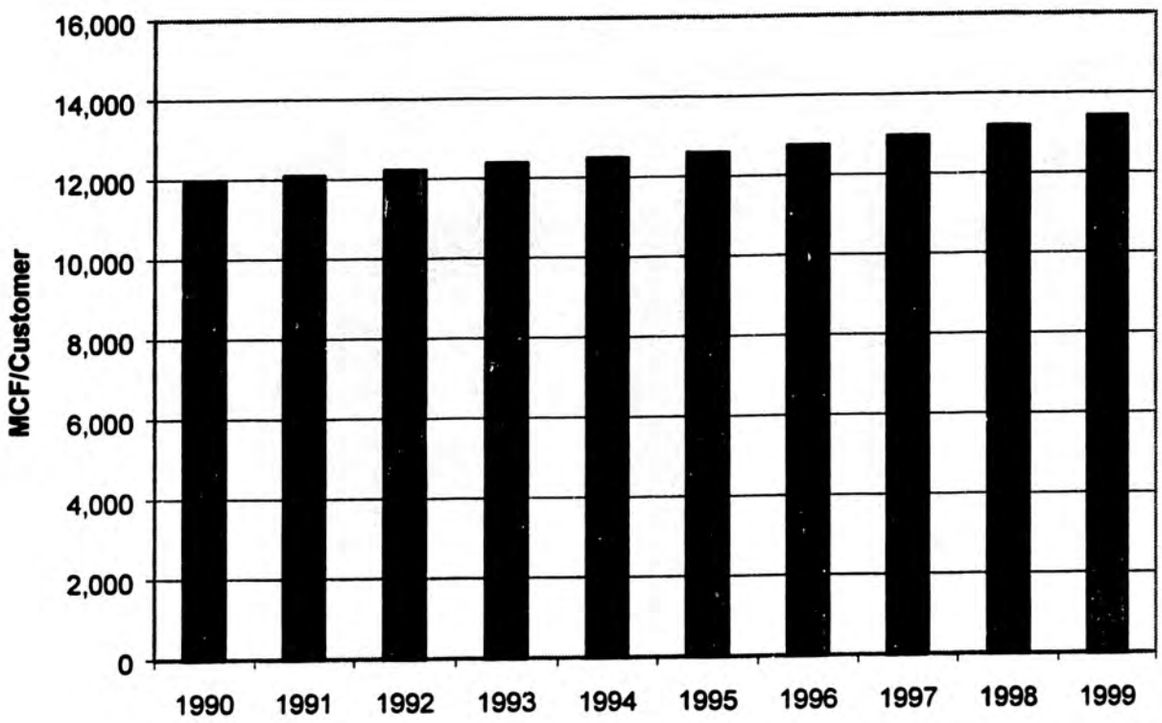

Figure 2.8: Commercial Average Usage

Source: US Department of Energy, Energy Information Administration. *Natural Gas Annual*

CHAPTER 3: REVIEW OF DEMAND AND SUPPLY MODELING LITERATURE

This chapter of our report presents an overview of general issues associated with demand modeling, an overview of various different approaches to modeling natural gas demand, as well as an overview of the methods that we will employ in the development of our baseline natural gas demand models.

For the more general reader, this chapter of the report can be skipped without loss of context of the overall study. For those readers looking for additional detail on the modeling of natural gas demand, Appendix 2 was prepared for this purpose.

3.1: General Issues in Modeling Demand

Modeling natural gas demand and supply in local, regional, and national markets is important for a number of reasons. These models give researchers and other market observers information about the structure and composition of demand and supply. Futhermore, the results of these models inform researchers about the magnitude of future demand and its sensitivity to key determinants such as energy prices and income. This information is used to understand:

- Past trends and the determinants of realized demand and supply;
- The responsiveness of demand and supply to changes in its important determinants; and
- Future demand and supply under different assumptions about future scenarios.

From its most basic perspective, the relationships of demand and supply can be summarized as:

- Demand is a function of prices, income, and tastes and preferences; and
- Supply is a function of input factor prices, technology, and other factors.

Transforming these theoretical relationships into measurable statistical equations is difficult. The way empirical data is measured may not conform with the structure implied by theory. For instance, theory suggests that the quantity demanded is a function of prices and other important variables. Yet the "appropriate" prices may not be readily available or easily generated. Furthermore, in many energy pricing situations, prices are set in a multitude of different manners (i.e, average rates, two-part tariffs, increasing block rates,

decreasing block rates, time of day and seasonal pricing, etc.) Data measurement problems in terms of definition, sampling, and aggregation complicate model specification and statistical estimation.

Most quantitative analyses of supply and demand are broken into two types: cross sectional and time series. Cross sectional models typically examine causal relationships across a collection of variables over a fixed period of time. As suggested by the nomenclature, time series models focus on time dependency.

Cross sectional models are used to examine existing determinants of either supply and demand. These models are structural in nature since they attempt to flush out causality and typicially employ many different determinants of demand or supply as independent (explanatory) variables. Thus, a model of the industrial demand for energy, could consider a number of different explanatory factors that include economic characteristics (i.e., relative energy prices, output levels, etc.) and technical characteristics of the facilities (i.e., number of boilers, fuel switching abilities, heat to power ratios, etc.).

Cross sectional models provide useful information on the relative statistical importance of these variables at a given period of time but are less useful in estimating how relationships change over time. Thus, their ability to serve as a springboard for forecasting is limited. In addition, these types of approaches usually require detailed disaggregate information (usually at the firm or production or consumption unit level), that can be difficult to acquire, particularly for independent research.

Time series models, on the other hand, are more useful in examining the dynamic determinants of demand or supply. The advantage of time series models is that they can convey information about how supply or demand relationships have varied historically, and where particular "structural breaks" in certain trends have occurred. These models are equally useful as a starting point for forecasting since most forecasts are developed from historical trend relationships. Their disadvantage is that data availability usually limits the range of the determinants measuring the supply or demand relationship.

Another consideration in time series models is that they can be developed in two different fashions. The first is traditionally referred to as a "structural econometric" approach while the second is commonly referred to more generally as a "time series" approach.[1] The structural econometric approach is concerned with the estimation of relationships suggested by economic theory across time. For instance, in demand analysis we might look at the relationship of energy demand relative to prices, income, weather, and other relevant variables. Such models serve two purposes. First, they allow economic hypotheses to be tested

[1]A seminal text on the econometric analysis of time series is Andrew Harvey. (1991) *The Econometric Analysis of Time Series*. Second Edition. Cambridge, Massachusetts: The MIT Press.

empirically.[2] Second, they provide a framework for making rational and consistent predictions (i.e., forecasting).

Pure time series approaches, on the other hand, are more generalized trend analyses based on statistical extrapolation techniques rather than theoretic relationships. Traditional time series analysis forecasts the time path of a variable with models that explicitly contain stochastic components to measure their dynamic relationships.[3] Difference equations, such as moving averages of either the error term, the dependent variable, or both, are at the core of these types of approaches. Uncovering the dynamic path of a series improves forecasts since the measurable components of the series can be extrapolated into the future.

There is a third modeling option known as cross-sectional/time series models. These approaches, as the name suggests, merge these two approaches to maximize the relative benefits, and minimize their relative shortcomings. The problem is that, in many instances, pooled cross sectional approaches require relatively advanced statistical techniques, as well as being very data intensive.

Another important question in measuring either supply or demand relationships is the determination of which of the two general approaches should be facilitated. In many instances, this is usually done by purpose of the study as well as the practical limitations of the data. If a researcher is interested in examining the price elasticity of the residential demand for natural gas, then a cross sectional analysis of account-specific information would be a useful approach. However, many researchers outside of natural gas local distribution companies usually have limited or no access to this type of information. The US Department of Energy, however, does report aggregate information by customer class across time, thus some type of time series approach may be more readily facilitated.

Lastly, determining the appropriateness of a particular model is an important specification issue. Often, applied modeling can emphasize goodness of fit of a particular model to the expense of all other considerations. However, more balanced consideration should include such factors as:

- *Consistency with theory.* Ensuring the quantitative estimates of model parameters exhibit mathematical signs and magnitudes consistent with economic theory (i.e., negative price elasticities and positive income elasticities).

- *Consistency with goals.* Obviously specifying and measuring time series models can be more important for forecasting goals, while cross sectional models can be more important for research

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[2] *Ibid.*, 1.

[3] Walter Enders. (1995). *Applied Econometric Time Series.* New York: John Wiley and Sons, Inc.

questions related to the relative importance of structural determinants.

- *Parsimony.* Ensuring that models that are not overly specified and are straightforward.

- *Robustness.* Ensuring that models are not overly dependent upon unique specifications or time periods under consideration.

The modeling of supply and demand for natural gas builds on a broad arena of industry-based energy modeling. Natural gas supply modeling, for instance, is conditioned by a number of earlier studies in petroleum supply modeling. Natural gas demand modeling is heavily linked to the electric power industry.

The study of natural gas supply and demand also is linked to technical-engineering models, sociological models, economic models, and hybrid models that employ varying combinations of these factors. Econometric analysis, as opposed to time series approaches, has dominated much of the supply and demand modeling literature. The preference for these econometric approaches is probably to be expected. First, econometric approaches are useful in explaining the changes in natural gas disposition that result from general changes in the industry—particularly, the response to shifts in price and the general degree of price volatility in the industry since the early 1970s.

Second, while data measurement and implementation is still a challenge in the analysis of energy demand and supply, accessibility of the information has improved considerably. Reporting requirements and data collection developed at the U.S. Department of Energy gives researchers a consistent source of information to examine and corroborate existing studies in the energy industry. With the advent of the internet, the electronic availability of the information enhances the ability to concentrated important efforts in understanding empirical relationships rather than collecting basic information on industry disposition and trends.

Third, over the past twenty years, econometric approaches have become more accessible to industry practitioners as software packages have reduced the programming work needed to do the earlier models by an exceptional order of magnitude. Today, many readily available statistical packages can estimate either supply or demand models in matter of seconds. The reduction in computational difficulty has helped facilitate the development of a large body of analysis related to important energy relationships.

3.2: Empirical Studies of Natural Gas Demand

One of the pioneering authors in demand modeling, for many sectors that go beyond just energy demand modeling, is Hendrick S. Houthakker. His studies in energy demand modeling were extensive, and provided some of the first insights into the importance many structural determinants of energy demand. His work is still commonly cited in principal textbooks of microeconomic theory.[4] Houthakker's work in energy demand modeling, developed in the early 1950s, was a basis for his broader work in overall demand modeling.[5]

On the more practical side, there is a considerable amount of work in natural gas demand modeling that rests outside the traditional academic literature. This work is associated with the modeling conducted within the process of regulated natural gas distribution companies, commonly referred to as local distribution companies or LDCs. These LDCs use forecasting models for internal planning process in meeting supply (commodity) and capacity (transportation and storage) needs.[6]

Many of the theoretic developments of natural gas demand modeling have come from the academic literature. A good portion of this analysis has focused on residential, and to a lesser degree commercial, demand for natural gas. These models are primarily econometric in nature since the purpose of many are to get accurate estimates of price, income, and weather related sensitivities of natural gas demand.

Another practical consideration in reviewing the literature on natural gas modeling is its relationship with its sister energy industry, electricity. A number of the earliest works in energy demand concentrated in the area of electricity (i.e., Houthakker) and not natural gas. It seems likely that one of the initial reasons for more comprehensive development of demand modeling in the electricity industry is associated with its greater degree of data availability. Thus, any survey of natural gas demand modeling will have to include some references to the development in the power industry as well.

There are a number of surveys in the literature dedicated to natural gas and energy demand modeling in general. One of the earliest and most comprehensive surveys of energy demand modeling was prepared by Douglas R. Bohi for the Electric Power Research Institute (EPRI).[7] While the overall

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[4]Hendrick S. Houthakker and Lester D. Taylor. (1966). *Consumer Demand in the United States, 1929-1970*. Cambridge: Harvard University Press.

[5]For instance see: Hendrick S. Houthakker. (1951), "Some Calculations of Electricity Consumption in Great Britain." *Journal of the Royal Statistical Society*. Series A, 114, Part III, 351-71.

[6]A general primer on the role of natural gas demand forecasting and how it relates to overall LDC planning can be found in: Charles Goldman, et al. (1993). *Primer on Gas Integrated Resource Planning*. Berkeley, California: Lawrence Berkeley Laboratories.

[7]Douglas R. Bohi. *Price Elasticities of Demand for Energy: Evaluating the Estimates*. Palo Alto: Electric Power Research Institute.

purpose of the study was to examine price elasticities, the study is an excellent overview of demand modeling since price elasticities are usually outputs derived from an overall analysis of demand determinants. An update to this study was prepared in 1984 by Bohi and Zimmerman.[8]

A more recent study, which emphasizes the development of the literature in residential energy demand modeling, was presented by Reinhard Madlener.[9] In the survey, Madlener attempts to update the earlier Bohi work, as well as breaking the existing econometric literature into a number of useful different categories. These include studies associated with log-linear functional forms, transcendental logarithmic (translog) functional forms, qualitative choice models (also know as discrete choice models), household production theory (end-use modeling), and pooled time series-cross sectional models.

Madlener presents a table associated with each of these types of models. This table has been replicated, with additional comments and analysis, in Appendix Table A.2.1. The following discussion provides a brief overview of the literature along the lines developed by Madlener. A more detailed discussion of each of the general demand modeling methods is provided in Appendix 2.

3.2.1: Log-Linear and Double Log Models: The typical log-linear and double log models are relatively straightforward and tend to be the model of choice, particularly for industry practitioners. The benefit of the log-linear and double log form is that coefficients can easily be translated into elasticities. In the double log form, the parameter for price is interpreted as the price elasticity of demand, while the parameter estimate for income can be interpreted as the income elasticity of demand.

3.2.2: Transcendental Logarithmic (Translog) Models: Translog models became popular in the 1970s with the advent of the Christensen, et al. (1973) approach of estimating industrial production, and later with cost functions and consumer-utility functions.[10] This approach was applied to the electric power

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[8]Douglas R. Bohi and Martin B. Zimmerman. (1984). "An Update on Econometric Studies of Energy Demand Behavior." *Annual Review of Energy*. 9: 105-54. The Bohi and Zimmerman (1984) elasticity estimates vary considerably but two general conclusions emerge. First, price elasticities for residential tend to be under 1.0. Two, elasticities are higher (in absolute value) as the analysis moves residential to commercial, to industrial customers. Elasticities increase in absolute value since larger customers tend to have more fuel substitution opportunities.

[9]Reinhard Madlener. (1996). Econometric Analysis of Residential Energy Demand: A Survey. *Journal of Energy Literature*. 2:3-32.

[10]Laurits Christensen, Dale Jorgenson, and Lawrence Lau. (1973) "Transcendental Logarithmic Production Frontiers." *The Review of Economics and Statistics*. 55:28-45. Laurits Christensen, Dale Jorgenson, and Lawrence Lau. (1975) "Transcendental Logarithmic Utility Functions." *The American Economic Review* 65: 367-83.

industry in 1976, and has become commonplace for a considerable amount of the energy economics research.[11]

The translog specification is a quadratic function with its elements expressed in terms of their natural logarithm. This specification is a second order approximation around a given point for the Cobb-Douglas production function. The Cobb-Douglas production function allows declining marginal products for all inputs, and also assumes that opportunities exist to substitute inputs in production without gaining or losing output.

The advantage of the translog approach is that it provides some structure on the assumed production/utility function under investigation. The parameters associated with the own and cross-price terms provide estimates of own and cross-price elasticities of demand. In additional, the translog approach allows for a more flexible functional form that enables empirical validation of utility-function properties. For example, while the Cobb Douglas function imposes unitary elasticity of substitution among inputs, the translog enables the data to determine the degree of input substitutability. In general, this flexible functional form enables the data to determine if the assumed functional form is correct, and imposes fewer a-priori restrictions on model specification.

The approach, however, is not without its potential problems. First, translog models require a significant amount of information, which can be difficult to attain. Second, these models can be relatively difficult to apply and interpret. This has led many practitioners to steer clear of these approaches. Third, the parameter estimates in many instances do not tend to be robust or stable, and can lead to some erroneous results. Last, the model tends to lend itself better to cross-sectional analyses, and, as a result, is not a very useful tool for forecasting.

3.2.3: Qualitative Choice and End Use Models: Most demand models prior to the early to mid 1970s, and even to this day, use continuous variables to measure energy consumption. There are equally interesting empirical applications, however, that examine not how much of a particular resource is utilized, but whether or not that resource is utilized at all. Such approaches are discrete in nature and have led to the development of qualitative choice, or discrete choice models of energy usage.

Discrete choice models are those in which the dependent variable is a discrete variable. The simplest application is one where the dependent variable is a binary choice variable that represents a simple positive or negative response. The dependent variable takes the value 1 if the choice is made, and 0 if the choice is not made. Independent variables are then used to estimate parameters influencing that choice.

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[11]Laurits Christensen and William Greene. (1976). "Economies of Scale in U.S. Electric Power Generation." *Journal of Political Economy*. 84 (4): 655-76.

Discrete choice models can be powerful tools to examine individual customer choice behavior and the factors influencing those decisions. Sensitivities, developed through the calculation of odds ratio statistics, can then be derived. These odds ratio statistics give some indication on how the probability of making a particular discrete energy consumption decision change as the independent variables change. In some natural gas and energy end use applications, these models provide interesting information on appliance usage and potential changes in penetration rates resulting from shifts in natural gas prices.

These qualitative based models, however, usually require specific and relatively comprehensive end use information. Typically, data used in these types of analyses are from individual consumer surveys. Thus, such empirical approaches are limited, if customer, or decision making unit information is not available. In addition, these types of models can tend to be more static in nature making it difficult to use for long forecasting and trend analysis.

3.3: Methods and Data Used to Develop the Baseline Demand Model

As noted above, there are a number of empirical modeling techniques that have been facilitated in the literature. However, one of the most common and successful approaches for examining natural gas demand are the log-linear and double log models first developed in the 1960s. Our baseline models of natural gas demand are based upon those approaches. There are a number of advantages associated with the traditional double-log models. These include:

- They are straightforward approaches that are parsimonious and easier to implement;
- They are general models that are applicable to a wide range of data;
- In the absence of detailed, account specific survey data, these models serve as the best approach for fitting demand curves for the broad customer classes we are examining (i.e., residential, commercial, and industrial);
- The majority of the past academic and trade literature has been based upon these approaches; and
- These approaches have the advantage of providing considerable descriptive information in addition for being good tools for developing forecasts.

This study has developed baseline models for each major consuming sector in Alaska's natural gas markets. These include residential, commercial, industrial, and electric utility.

In looking at natural gas demand, the goal was to find a consistent source of information that was documentable and widely accepted as authoritative. Based upon our past experience, we have found that the information provided by the Department of Energy, Energy Information Administration (EIA) provides the most comprehensive, and documentable source of information for natural gas usage. This information is compiled annual by the EIA in EIA Form 176. A discussion of EIA Form 176, and the data collected in this annual survey.

The descriptive statistics for all the variables that were utilized in the baseline demand models are presented in Table 3.1.

Table 3.1: Descriptive Statistics for Baseline Model Dataset (1986 – 1999)

Variable Name	Number of Observations	Mean	Standard Deviation	Minimum	Maximum
Residential NG Usage, Mcf/yr	14	14,364,367	1,561,998	12,090,998	17,633,864
Commercial NG Usage, Mcf/yr	14	23,010,401	3,015,288	20,002,655	27,667,159
Industrial NG Usage, Mcf/yr	14	70,717,120	7,004,328	59,341,410	80,937,950
Electric Utilities NG Usage, Mcf/yr	15	31,306,872	2,323,032	28,024,737	35,569,901
Number of Residential Customers	14	75,892	7,242	65,953	88,924
Number of Commercial Customers	14	12,290	643	11,243	13,409
Number of Industrial Customers	14	9.29	1.77	7.00	13.00
Average Revenue from Residential Customers (1999 $/Mcf)	14	4.20	0.42	3.58	4.88
Average Revenue from Commercial Customers (1999 $/Mcf)	14	2.91	0.45	2.18	3.51
Average Revenue from Industrial Customers (1999 $/Mcf)	14	1.38	0.16	0.99	1.58
Heating Degree Days at Fairbanks (Base 65 degrees F.)	14	13,605	802	12,244	15,142
Per Capita Income (1999 $)	14	27,383	713	25,966	28,629
Manufacturing Gross State Product (1999 $ MM)	14	1,226	199	684	1,457

Data Sources:	***Variables***
EIA-176 "Annual Gas Supply and Disposition Report", 1986-1999	Usage, number of customers, and average revenue for all customer classes except electric utilities.
EIA Electric Power Annual, 1986-2000	Industrial NG Usage
NOAA National Climatic Data Center website	Heating Degree Days
BEA website	Per Capita Income and Gross State Product

CHAPTER 4: BASELINE IN-STATE NATURAL GAS DEMAND FORECASTS

The results from our baseline in-state natural gas demand models are summarized in this chapter of the report. A more detailed description of the statistical models used in this forecast is presented in Appendix 3.

Our baseline in-state natural gas demand forecasts are developed under a set of "business as usual" assumptions. We have forecast in-state natural gas demand for each major customer class to the year 2020 under the assumption that trends over the past five years will be maintained into the forecast period. In the following chapter of our report, we will examine the sensitivities of these forecasts to changes in the underlying assumptions associated with these past trends.

We use a three-fold approach to forecast baseline natural gas demand. First, we estimate econometric time-series models. Natural gas usage in each major sector (residential, commercial, industrial and electric power generation) is the dependent variable to be explained. Explanatory variables include personal income, gross state product, prices, weather, and other important determinants of natural gas demand. The magnitude of these impacts (i.e., elasticities) and their statistical properties are presented in Appendix 3.

Second, we estimate traditional time series trend models. The time series approach extrapolates the underlying trend in natural gas usage over time for each sector. This approach is useful because it is simple to apply and straight forward to interpret. The detailed statistical results, along with a discussion of each of these types of methods, are also presented in Appendix 3.

Third, we average the results of the separate econometric and time-series trend models described above to form a combined forecast. This approach helps pick up the peaks, valleys, and underlying trends in data and is a useful tool for forecasting. The forecast information from each of these approaches has been provided in tables in this chapter of our report. The detailed results from each of the approaches, and their related statistical output, have been provided in Appendix 3.

4.1: Residential Baseline Forecast

The results from our residential in-state demand model are presented in Table 4.1.

Table 4.1: Residential Baseline Demand Forecast (2000-2020)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1986	12,090,998	12,198,225		12,198,225
1987	12,256,280	12,499,708	12,406,056	12,452,882
1988	12,529,140	12,808,641	12,540,566	12,674,604
1989	13,588,767	13,125,210	13,655,173	13,390,191
1990	14,164,886	13,449,602	14,151,008	13,800,305
1991	13,561,759	13,782,013	13,445,474	13,613,744
1992	14,349,944	14,122,639	14,537,644	14,330,141
1993	13,857,568	14,471,683	13,585,834	14,028,759
1994	14,895,199	14,829,354	14,873,428	14,851,391
1995	15,230,778	15,195,865	14,947,440	15,071,653
1996	16,179,216	15,571,435	15,908,103	15,739,769
1997	15,146,116	15,956,287	15,415,471	15,685,879
1998	15,616,617	16,350,651	15,926,681	16,138,666
1999	17,633,864	16,754,761	17,594,905	17,174,833
2000	--	17,168,859	17,867,599	17,518,229
2001	--	17,593,192	18,087,424	17,840,308
2002	--	18,028,012	18,310,890	18,169,451
2003	--	18,473,578	18,537,190	18,505,384
2004	--	18,930,157	18,766,257	18,848,207
2005	--	19,398,021	18,998,187	19,198,104
2006	--	19,877,448	19,232,955	19,555,201
2007	--	20,368,724	19,470,649	19,919,686
2008	--	20,872,142	19,711,255	20,291,698
2009	--	21,388,002	19,954,860	20,671,431
2010	--	21,916,612	20,201,450	21,059,031
2011	--	22,458,286	20,451,117	21,454,701
2012	--	23,013,349	20,703,866	21,858,607
2013	--	23,582,129	20,959,711	22,270,920
2014	--	24,164,967	21,218,750	22,691,858
2015	--	24,762,210	21,480,954	23,121,582
2016	--	25,374,215	21,746,434	23,560,325
2017	--	26,001,345	22,015,159	24,008,252
2018	--	26,643,974	22,287,242	24,465,608
2019	--	27,302,487	22,562,653	24,932,570
2020	--	27,977,274	22,841,498	25,409,386
Root Mean Square Error		0.01753		

The results from our in-state residential demand forecast show relatively healthy growth in natural gas usage from the existing residential customer base in Alaska. Overall, we forecast that natural gas demand will grow at an annual average rate of about 1.8 to 1.9 percent per year, under baseline conditions, until 2020. Baseline conditions included a half percent increase per year in per capita income and zero percent increase in real retail residential natural gas prices. In the next chapter of our report, we examine the sensitivity of this forecast to changes in those underlying assumptions.

Under our baseline forecast, residential in-state natural gas usage will grow from a 1999 level of 17 Bcf to 25 Bcf by the year 2020. A graph of this longer run trend is presented below in Figure 4.1

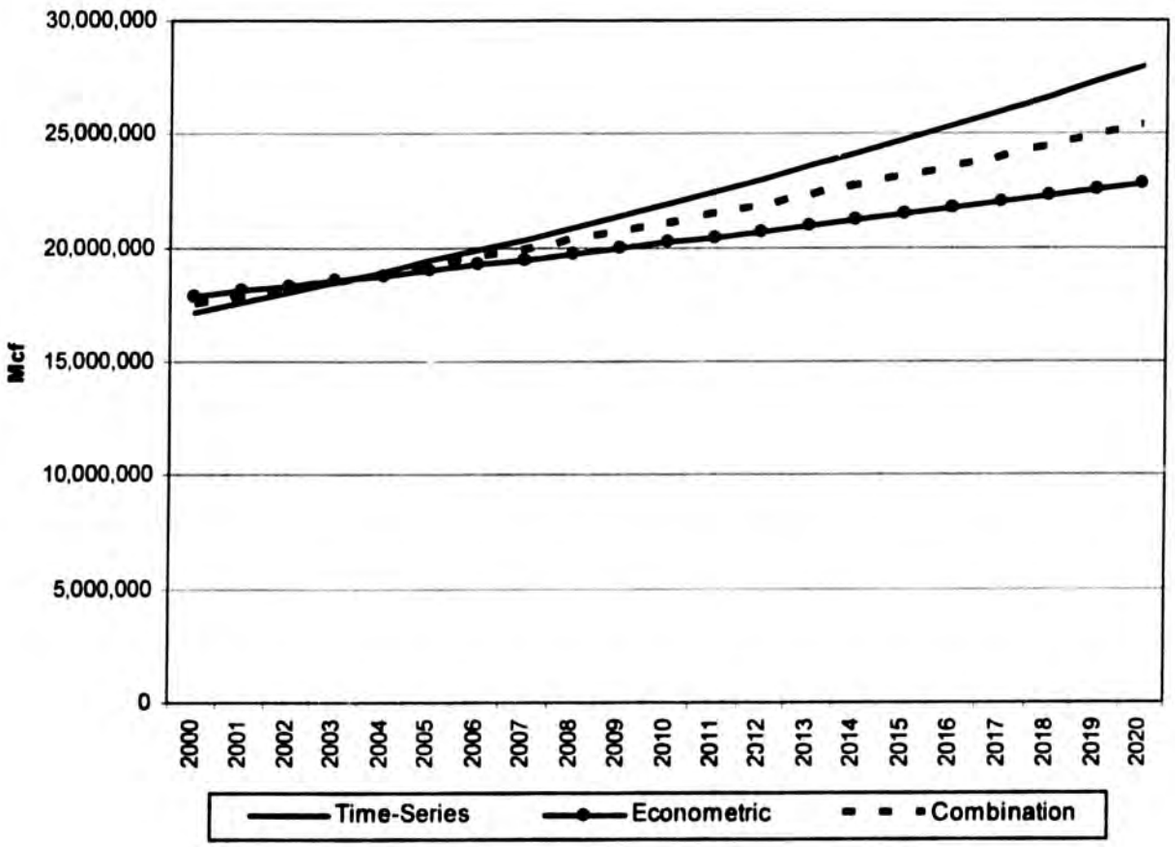

Figure 4.1: Residential Baseline Demand Forecast (2000-2020)

4.2: Commercial Baseline Forecast

Our commercial in-state demand forecast is presented in Table 4.2. A graph of these longer run trends is presented in Figure 4.2. Under business as usual conditions, we forecast long-term commercial natural gas usage to grow at a relatively moderate pace. The average annual rate of growth over the forecast period varies from a high of 1.7 percent in the 2003-2004 time period, to around 1.0 percent or less for the period 2010 onwards.

Commercial natural gas usage is forecast to grow from a 1999 level of 28 Bcf to a 2020 forecast level of 35 Bcf. This forecast assumes zero percent real changes in commercial natural gas prices and a half percent annual increase in per capita income. Deviations from this forecast assumption, and its implications for commercial natural gas usage, will be considered in the following chapter.

Table 4.2: Commercial Baseline Demand Forecast (2000-2020)

Date	Actual (Mcf)	Predicted Time Series (Mcf)	Predicted Econometric (Mcf)	Predicted Combination (Mcf)
1986	20,874,011	20,872,099		20,872,099
1987	20,224,143	21,459,238		21,459,238
1988	20,842,041	20,808,703	20,952,886	20,880,795
1989	21,738,412	21,424,696	21,111,727	21,268,211
1990	21,621,850	22,320,431	21,608,730	21,964,580
1991	20,897,429	22,203,516	20,147,636	21,175,576
1992	21,299,274	21,477,732	20,996,129	21,236,931
1993	20,002,655	21,877,606	20,617,698	21,247,652
1994	20,697,859	20,580,149	22,079,885	21,330,017
1995	24,978,977	21,272,817	24,597,540	22,935,179
1996	27,314,942	25,553,385	27,507,854	26,530,620
1997	26,908,231	27,892,388	27,310,569	27,601,479
1998	27,078,631	27,486,776	25,963,527	26,725,151
1999	27,667,159	27,655,530	27,727,955	27,691,742
2000	--	28,242,988	28,890,145	28,566,567
2001	--	28,818,167	28,999,111	28,908,639
2002	--	29,392,686	29,012,758	29,202,722
2003	--	29,966,545	29,338,263	29,652,404
2004	--	30,539,746	29,796,778	30,168,262
2005	--	31,112,288	30,016,438	30,564,363
2006	--	31,684,173	29,997,933	30,841,053
2007	--	32,255,402	29,832,200	31,043,801
2008	--	32,825,975	29,696,295	31,261,135
2009	--	33,395,893	29,666,724	31,531,308
2010	--	33,965,156	29,738,479	31,851,818
2011	--	34,533,766	29,843,132	32,188,449
2012	--	35,101,723	29,920,323	32,511,023
2013	--	35,669,028	29,946,149	32,807,588
2014	--	36,235,682	29,937,088	33,086,385
2015	--	36,801,685	29,923,989	33,362,837
2016	--	37,367,038	29,929,179	33,648,108
2017	--	37,931,743	29,955,787	33,943,765
2018	--	38,495,799	29,993,163	34,244,481
2019	--	39,059,207	30,028,044	34,543,626
2020	--	39,621,969	30,053,513	34,837,741
Root Mean Square Error		0.04907		

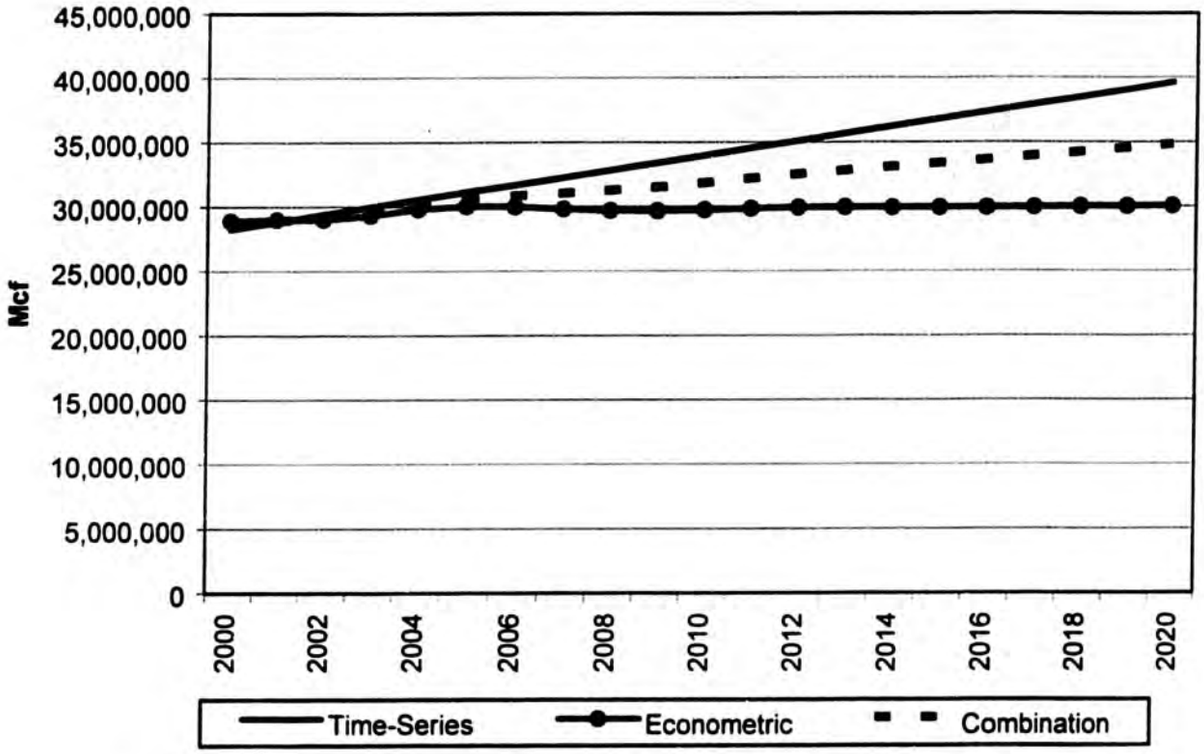

Figure 4.2: Commercial Baseline Demand Forecast (2000-2020)

4.3: Industrial Baseline Forecast

The results from the industrial in-state demand forecast are presented in Table 4.3. A graph of these longer run trends is presented in Figure 4.3. Our forecast assumes no greater than average growth in either the number of industrial customers, or their average usage. In addition, the baseline forecast assumes that current economic conditions and prices will hold relatively stable.

The average annual rate of growth for industrial natural gas usage over the forecast period is half of one percent. Industrial natural gas usage is forecast to grow from a 1999 level of 74 Bcf to a 2020 forecast level of 81 Bcf.

Given the relatively limited historic growth of industrial customers and usage, our forecast for future use is somewhat limited. We anticipate relatively constant growth, under baseline conditions, for industrial consumption. The addition of new industrial customers, however, could impact this forecast. In later chapters of this report, we examine the addition of new industries to Alaska and their implications for industrial and large volume customer usage. Sensitivities to our baseline forecast are also considered in the subsequent chapter.

Table 4.3: Industrial Baseline Demand Forecast (2000-2020)

Date	[illegible] (Mcf)	[illegible] (Mcf)	Predicted Econometric (Mcf)	Predicted Combination (Mcf)
1986	60,438,785	65,983,516	60,953,186	63,468,351
1987	67,467,489	66,711,763	70,090,074	68,400,918
1988	67,804,860	67,440,010	68,568,283	68,004,146
1989	59,341,410	68,168,256	73,723,646	70,945,951
1990	76,849,333	68,896,503	73,991,984	71,444,243
1991	75,637,177	69,624,750	74,064,575	71,844,662
1992	80,937,950	70,352,997	70,766,558	70,559,778
1993	75,794,979	71,081,244	69,802,135	70,441,689
1994	61,404,028	71,809,491	67,148,789	69,479,140
1995	64,977,342	72,537,737	71,056,370	71,797,053
1996	75,616,070	73,265,984	70,741,268	72,003,626
1997	73,599,299	73,994,231	71,538,235	72,766,233
1998	75,946,906	74,722,478	73,864,793	74,293,635
1999	74,224,056	75,450,725	70,231,772	72,841,248
2000	--	76,178,972	70,298,379	73,238,676
2001	--	76,907,218	70,365,044	73,636,131
2002	--	77,635,465	70,431,784	74,033,625
2003	--	78,363,712	70,498,588	74,431,150
2004	--	79,091,959	70,565,442	74,828,701
2005	--	79,820,206	70,632,373	75,226,290
2006	--	80,548,453	70,699,354	75,623,904
2007	--	81,276,699	70,766,412	76,021,556
2008	--	82,004,946	70,833,520	76,419,233
2009	--	82,733,193	70,900,705	76,816,949
2010	--	83,461,440	70,967,941	77,214,690
2011	--	84,189,687	71,035,253	77,612,470
2012	--	84,917,933	71,102,616	78,010,275
2013	--	85,646,180	71,170,057	78,408,118
2014	--	86,374,427	71,237,547	78,805,987
2015	--	87,102,674	71,305,116	79,203,895
2016	--	87,830,921	71,372,748	79,601,835
2017	--	88,559,168	71,440,431	79,999,800
2018	--	89,287,414	71,508,192	80,397,803
2019	--	90,015,661	71,576,003	80,795,832
2020	--	90,743,908	71,643,893	81,193,900
Root Mean Square Error		0.10026		

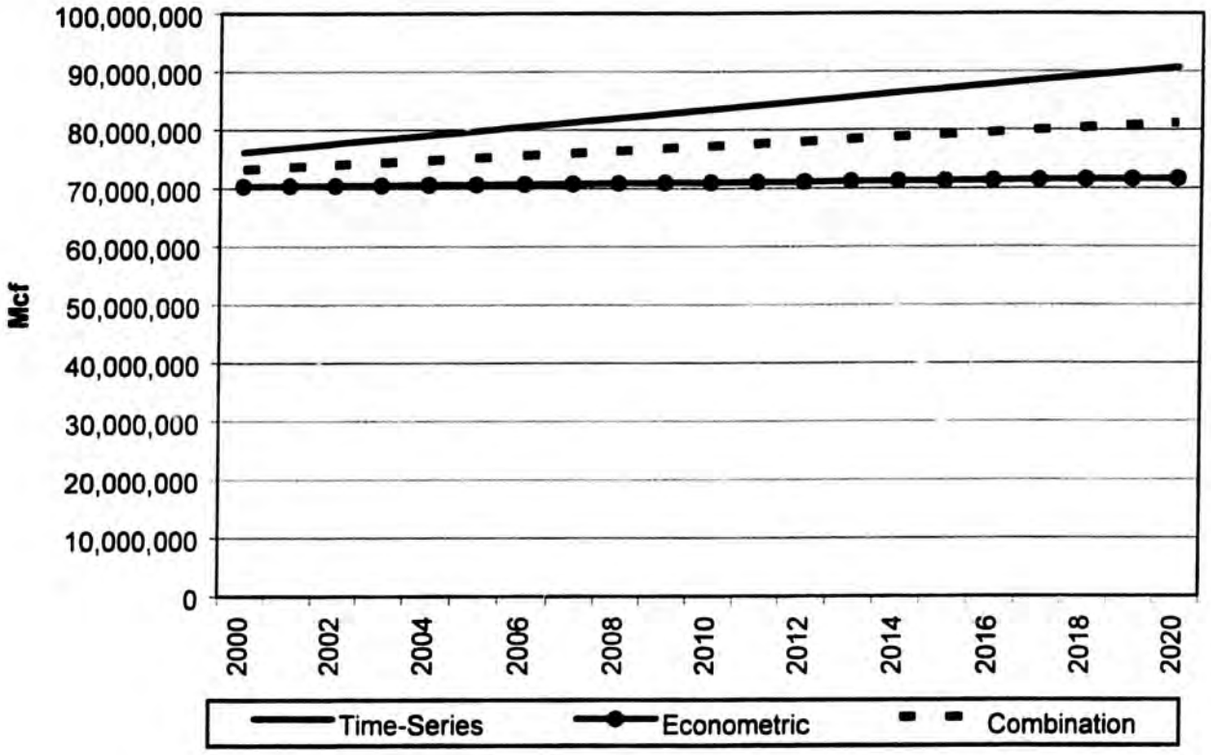

Figure 4.3: Industrial Baseline Demand Forecast (2000-2020)

4.4: Electric Utility Baseline Forecast

Our electric utility demand model was prepared in a manner different from than the other customer classes. First, we developed a long run trend forecast of power generation for Alaska's electric utilities. Second, we used the long run average trend for the gas-fired portion of the fuel mix to determine what proportion of that generation would come from gas-fired units. Third, we utilized the long run trend in power plant heat rates to estimate the future operating efficiency of total in-state power generation. This efficiency rating allows us to estimate the amount of natural gas that would be used for power generation under business as usual conditions. The forecast assumes that no new power generation facilities will be brought on line during the forecast period.

The results from the baseline electric utility demand forecast can be found in Table 4.4 while a graph of forecast electric utility natural gas usage has been provided in Figure 4.4. Baseline forecast electric utility usage is anticipated to grow from a level of 31 Bcf in 1999 to 41 Bcf by the year 2020. Sensitivities to this forecast are also considered in the following chapter of this report.

Table 4.4: Electric Utility Baseline Demand Forecast (2000-2020)

Date	Actual Data (Mcf)	Predicted Time-Series (Mcf)
1986	34,409,000	33,670,793
1987	30,530,000	31,234,619
1988	30,841,000	31,418,047
1989	32,746,000	32,312,018
1990	34,366,142	33,549,084
1991	31,329,758	32,470,899
1992	28,953,390	31,259,209
1993	28,024,737	27,867,045
1994	29,047,703	28,129,752
1995	29,808,627	28,661,334
1996	31,154,273	29,541,429
1997	33,509,748	31,362,521
1998	28,784,955	30,332,479
1999	30,527,841	32,409,397
2000	--	35,656,886
2001	--	32,949,652
2002	--	33,655,948
2003	--	34,119,758
2004	--	34,899,977
2005	--	35,406,497
2006	--	35,330,693
2007	--	35,813,699
2008	--	36,248,792
2009	--	36,677,751
2010	--	37,031,714
2011	--	37,353,364
2012	--	37,759,602
2013	--	38,149,476
2014	--	38,529,726
2015	--	38,899,627
2016	--	39,272,923
2017	--	39,657,179
2018	--	40,036,768
2019	--	40,414,176
2020	--	40,790,982

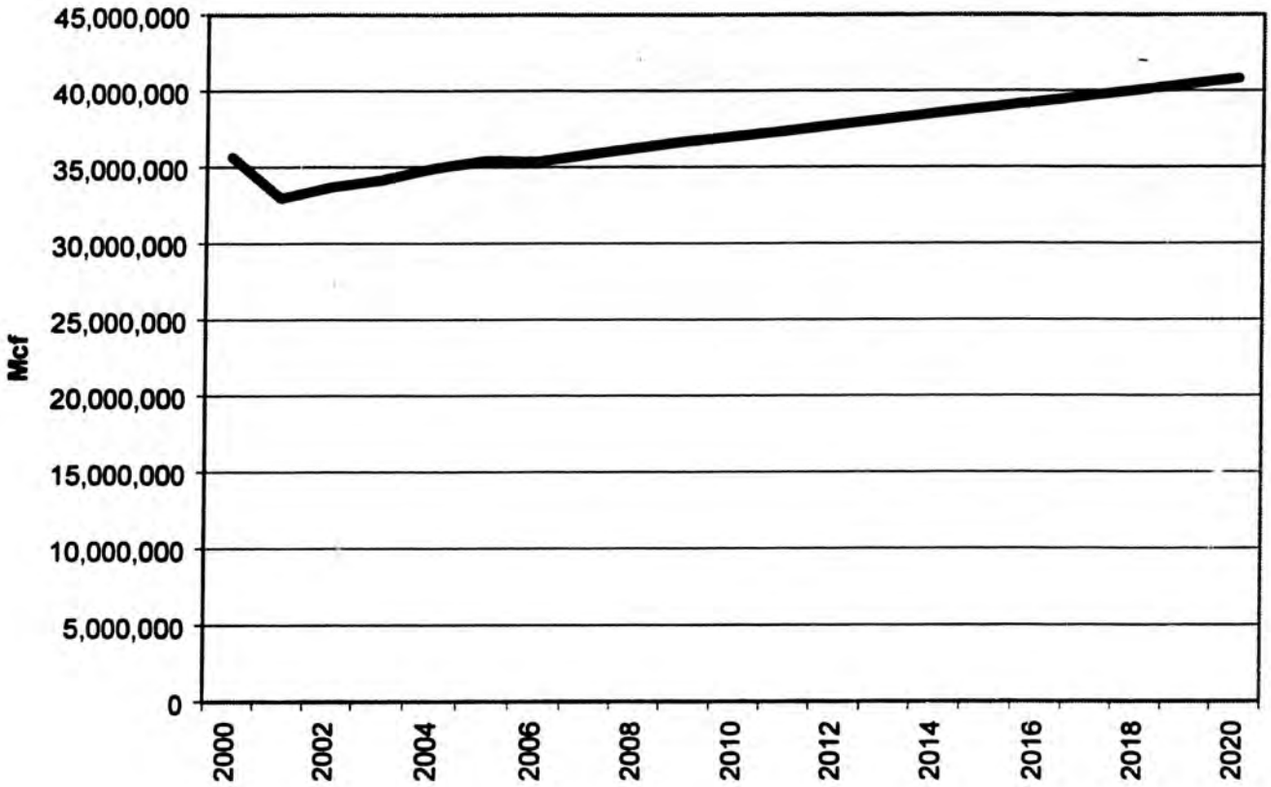

Figure 4.4: Electric Utility Baseline Demand Forecast (2000-2020)

4.5: Total Forecast Baseline In-State Demand

The aggregation of our baseline forecasts for each customer class can be summed to analyze total in-state demand until 2020 under business as usual conditions. The total baseline forecast is developed from our combination forecast. Total in-state, baseline usage, is presented in Table 4.5, while Figure 4.6 presents a graphical representation of annual baseline usage levels.

We anticipate that baseline forecast natural gas usage over the forecast period will grow by 27 Bcf. Residential customers will account for 24 percent of this growth, commercial customers will account for 22 percent of this growth, industrial customers will account for 22 percent of this growth, and electricity utilities will account for 32 percent of this growth. Sensitivities to the overall baseline forecast, and total forecast use by the year 2020, are explored in the next chapter of our report.

Table 4.5: Total In-State Baseline Demand Forecast (2000-2020)

Year	Actual Data (Mcf)	Baseline (Mcf)
1986	127,812,794	130,209,467
1987	130,477,912	133,547,658
1988	132,017,041	132,977,591
1989	127,414,589	137,916,372
1990	147,002,211	140,758,213
1991	141,426,123	139,104,881
1992	145,540,558	137,386,059
1993	137,679,939	133,585,145
1994	126,044,789	133,790,300
1995	134,995,724	138,465,219
1996	150,264,501	143,815,443
1997	149,163,394	147,416,112
1998	147,427,109	147,489,931
1999	150,052,920	150,117,221
2000	--	154,980,358
2001	--	153,334,730
2002	--	155,061,745
2003	--	156,708,696
2004	--	158,745,146
2005	--	160,395,253
2006	--	161,350,851
2007	--	162,798,743
2008	--	164,220,859
2009	--	165,697,439
2010	--	167,157,253
2011	--	168,608,985
2012	--	170,139,507
2013	--	171,636,103
2014	--	173,113,957
2015	--	174,587,941
2016	--	176,083,191
2017	--	177,608,996
2018	--	179,144,660
2019	--	180,686,203
2020	--	182,232,010

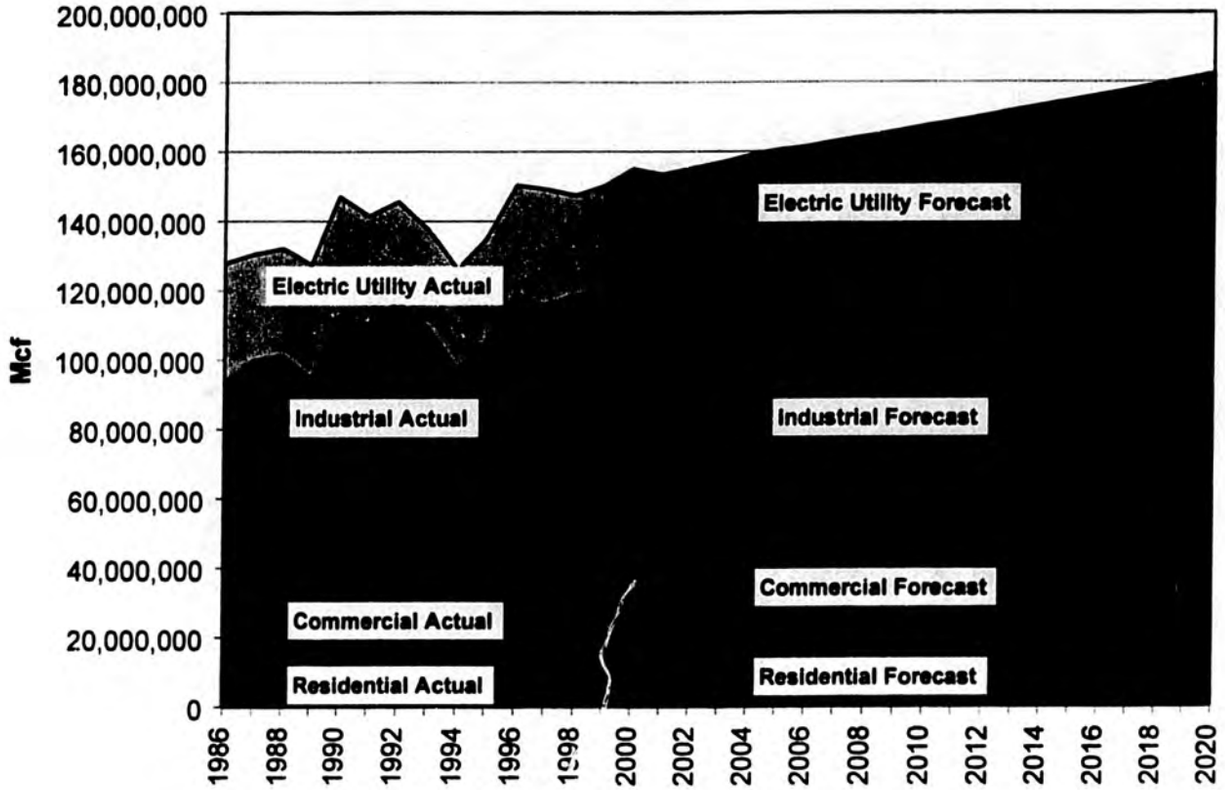

Figure 4.5: Total In-State Natural Gas Usage, Baseline Forecast (2000-2020)

CHAPTER 5: SENSITIVITY ANALYSIS OF BASELINE FORECAST

Our sensitivity analyses consisted of examining potential variations to our baseline forecast under varying economic assumptions. We examined two different scenario categories that could impact customer class natural gas usage: changes in prices; and changes in income. Specifically, each customer class baseline forecast was subject to the following scenarios:

(1) High Price Scenario: customer class natural gas prices were assumed to increase at an annual average rate of one percent, in real dollars, over the forecast period.

(2) Low Price Scenario: customer class natural gas prices were assumed to decrease at an annual average rate of one percent, in real dollars, over the forecast period.

(3) High Income Scenario: state personal income was assumed to increase at an annual average rate of one percent, in real dollars, over the forecast period. Gross state manufacturing product, the income proxy used for our industrial models, is assumed to increase by one percent per year as well.

(4) Low Income Scenario: state personal income was assumed to grow at an average annual rate of zero percent, in real dollars, over the forecast period. Gross state manufacturing product was also assumes to be constant in real dollars.

Our baseline assumptions are comparable to estimates prepared by the University of Alaska's Institute for Economic and Social Research (ISER). The most recent ISER base case forecast anticipates statewide average personal income growth of around one percent until the year 2020. Low personal income growth scenarios used in the ISER models utilize a 0.62 percent average annual growth rate, while the high personal income growth scenario is 2.13.[1]

5.1: Residential Baseline Forecast Sensitivity

Under our baseline forecast, we estimate that residential natural gas usage will increase from an annual level of approximately 17.5 Bcf in 2000 to a level of 21 Bcf in 2010. The increase at the end of the forecast period, 2020, is anticipated to be 25.4 Bcf. The total increase in residential natural gas usage over the ten year period is anticipated to be 3.5 Bcf and 7.9 Bcf for the twenty year period. This represents approximately a 20 percent increase over the ten year period

[1]Scott Goldsmith. *Economic Projects for Alaska and the Southern Railbelt: 2000-2025.* Anchorage: Institute of Social and Economic Research, October 3, 2001. Pages 2, 47, and 65.

and 45 percent increase over the twenty year period. The annual average rate of growth under the baseline forecast is 1.8 percent.

As noted earlier, we subjected each of our customer class forecasts to a number of sensitivities to measure the potential shift in usage that could result from either price or income swings. A comparison of the forecast residential usage levels under our various price scenarios are in Table 5.1.

Under our high natural gas price scenario, we estimate lower levels of residential natural gas usage (holding other variables constant). Under a high natural gas price scenario, residential annual natural gas usage will grow from a level of 17.5 Bcf in 2000 to a level of 20.7 Bcf in 2010 to a level of 24.7 Bcf in 2020.

Total residential usage during the forecast period is anticipated to grow at a slower rate than the baseline forecast. Overall, we anticipate a 1.7 percent annual average rate of growth if the longer run price decrease trend is dampened. Over a 10 year period (2000-2010) we anticipate residential natural gas usage to grow by 3.2 Bcf, and by 7.2 Bcf over the twenty year long run forecast period (2000-2020). This represents an 18.4 percent and 41.2 percent increase over the short run (2000-2010) and long run (2000-2020) forecast periods, respectively.

We also examined a scenario where natural gas prices fell at a greater rate than our baseline forecast. Under our low natural gas price scenario, there would be slightly greater residential natural gas usage. Under our low price scenario, we anticipate residential natural gas usage to grow at an annual average rate of 2 percent. During the short run period, this usage would grow by approximately 3.9 Bcf, and by 8.6 Bcf over the long run horizon.

Table 5.1: Forecast Residential Natural Gas Usage Under Different Price Scenarios

2000	17,518,229	17,500,093	17,536,585
2001	17,840,308	17,794,479	17,886,835
2002	18,169,451	18,095,331	18,244,930
2003	18,505,384	18,402,367	18,610,612
2004	18,848,207	18,715,675	18,983,999
2005	19,198,104	19,035,431	19,365,289
2006	19,555,201	19,361,751	19,754,627
2007	19,919,686	19,694,810	20,152,221
2008	20,291,698	20,034,739	20,558,223
2009	20,671,431	20,381,722	20,972,847
2010	21,059,031	20,735,890	21,396,261
2011	21,454,701	21,097,441	21,828,684
2012	21,858,607	21,466,526	22,270,300
2013	22,270,920	21,843,304	22,721,302
2014	22,691,858	22,227,984	23,181,928
2015	23,121,582	22,620,716	23,652,356
2016	23,560,325	23,021,717	24,132,845
2017	24,008,252	23,431,145	24,623,578
2018	24,465,608	23,849,231	25,124,821
2019	24,932,570	24,276,139	25,636,776
2020	25,409,386	24,712,105	26,159,711
Ten Year Increase	3,540,802	3,235,797	3,859,676
Twenty Year Increase	7,891,157	7,212,012	8,623,126

If state personal income were to increase above its past five year rates, we see significant opportunities for residential natural gas usage growth. Under our high income assumption, residential natural gas usage will increase from a level of 17.6 Bcf in 2000 to 21.9 Bcf in 2010 to 27.3 Bcf in 2020. This represents a 24.7 percent increase over the short run forecast period, and a 55.5 percent increase over the longer run forecast period. Under the high income scenario, residential natural gas usage would be approximately 1.9 Bcf above the long run baseline estimated growth levels. However, some caution should be given to these results. In order for these usage levels to be obtained, economic growth would have to remain uncharacteristically high over the entire forecast period.

The implication of low-income growth on residential natural gas usage over the different forecast periods is summarized in Table 5.2. Under the low-income assumptions, we anticipate much lower levels of natural gas usage. The average annual rate of growth during the forecast period would be approximately 1.6 percent. Total usage over the short run period (10 years) would increase by 2.8 Bcf, and by 6.3 Bcf over the long run forecast horizon.

The residential usage levels associated with different income levels are in Table 5.2.

Table 5.2: Forecast Residential Natural Gas Usage Under Different Income Scenarios

Year	Residential Base Case (Mcf)	Residential High Income Case (Mcf)	Residential Low Income Case (Mcf)
2000	17,518,229	17,584,947	17,451,674
2001	17,840,308	17,975,876	17,706,062
2002	18,169,451	18,376,091	17,966,365
2003	18,505,384	18,785,358	18,232,270
2004	18,848,207	19,203,831	18,503,889
2005	19,198,104	19,631,736	18,781,361
2006	19,555,201	20,069,301	19,064,823
2007	19,919,686	20,516,715	19,354,420
2008	20,291,698	20,974,220	19,650,301
2009	20,671,431	21,442,059	19,952,614
2010	21,059,031	21,920,440	20,261,517
2011	21,454,701	22,409,617	20,577,167
2012	21,858,607	22,909,852	20,899,726
2013	22,270,920	23,421,367	21,229,362
2014	22,691,858	23,944,434	21,566,245
2015	23,121,582	24,479,334	21,910,548
2016	23,560,325	25,026,305	22,262,453
2017	24,008,252	25,585,635	22,622,141
2018	24,465,608	26,157,632	22,989,802
2019	24,932,570	26,742,544	23,365,628
2020	25,409,386	27,340,683	23,749,813
Ten Year Increase	3,540,802	4,335,493	2,809,844
Twenty Year Increase	7,891,157	9,755,736	6,298,140

5.2: Commercial Baseline Forecast Sensitivity

Under our baseline forecast, we estimate that commercial natural gas usage will increase from an annual level of approximately 28.6 Bcf (2000) to 31.9 Bcf (2010) to 34.8 Bcf (2020). The total increase in commercial natural gas usage over this period is 3.3 Bcf (2000-2010) and 6.3 Bcf. Over the long run forecast period, we anticipate annual average growth to be one percent. This is consistent with historic trends when one out-lying year (1994-1995) is excluded from analysis.

Under our high price scenario, we estimate much lower levels of commercial natural gas usage. Our high commercial natural gas price scenario forecasts annual use to grow from a level of 28.5 Bcf in 2000 to 29.6 Bcf in 2010 and 30.7 Bcf in 2020. The annual average rate of growth during the period is less than one half percent. Total commercial usage over the forecast period, under our high natural gas price assumption, will grow by 1.1 Bcf over the short run forecast period (2000-2010) and by 2.2 Bcf over the longer run forecast period (2000-2020). For the year 2010, this would represent a 3.9 percent increase in commercial natural gas usage over the short run period and a 7.8 percent increase over the longer run period. Under our high price assumption, usage would be approximately 2.2 Bcf below the baseline short run forecast estimate and 4 Bcf over the longer run forecast period. The changes associated with each of our different price scenario forecasts are presented in Table 5.3.

Table 5.3: Forecast Commercial Natural Gas Usage Under Different Price Scenarios

Year	[illegible]	[illegible]	[illegible]
2000	28,566,567	28,451,442	28,683,799
2001	28,908,639	28,602,525	29,224,552
2002	29,202,722	28,671,009	29,760,330
2003	29,652,404	28,890,366	30,464,513
2004	30,168,262	29,170,069	31,249,292
2005	30,564,363	29,336,492	31,915,682
2006	30,841,053	29,395,288	32,457,978
2007	31,043,801	29,392,036	32,921,074
2008	31,261,135	29,407,258	33,402,273
2009	31,531,308	29,473,177	33,946,905
2010	31,851,818	29,585,393	34,555,030
2011	32,188,449	29,713,250	35,188,542
2012	32,511,023	29,831,304	35,811,692
2013	32,807,588	29,930,419	36,408,946
2014	33,086,385	30,018,098	36,989,250
2015	33,362,837	30,107,039	37,571,398
2016	33,648,108	30,205,861	38,169,861
2017	33,943,765	30,315,356	38,787,369
2018	34,244,481	30,431,127	39,417,553
2019	34,543,626	30,548,081	40,051,786
2020	34,837,741	30,663,720	40,685,286
Ten Year Increase	3,285,251	1,133,951	5,871,231
Twenty Year Increase	6,271,174	2,212,278	12,001,487

Under our low price forecast, commercial natural gas usage would increase considerably given this class' strong price sensitivity (i.e., price elasticity of demand). The average annual rate of growth under our low price scenario is well over 1.5 percent per year. Over the short run forecast period, commercial usage will grow by 5.9 Bcf and almost 12 Bcf over the longer run forecast period.

Table 5.4: Forecast Commercial Natural Gas Usage Under Different Income Scenarios

2000	28,566,567	28,576,984	28,532,498
2001	28,908,639	28,929,557	29,150,269
2002	29,202,722	29,234,126	29,474,563
2003	29,652,404	29,694,762	29,803,121
2004	30,168,262	30,222,057	30,103,978
2005	30,564,363	30,629,414	30,387,626
2006	30,841,053	30,916,930	30,668,380
2007	31,043,801	31,130,068	30,951,703
2008	31,261,135	31,357,778	31,237,019
2009	31,531,308	31,638,622	31,522,587
2010	31,851,818	31,970,191	31,807,560
2011	32,188,449	32,318,083	32,091,903
2012	32,511,023	32,651,874	32,375,815
2013	32,807,588	32,959,461	32,659,420
2014	33,086,385	33,249,113	32,942,736
2015	33,362,837	33,536,403	33,225,744
2016	33,648,108	33,832,619	33,508,427
2017	33,943,765	34,139,374	33,790,782
2018	34,244,481	34,451,290	34,072,809
2019	34,543,626	34,761,652	34,354,512
2020	34,837,741	35,066,944	34,635,893
Ten Year Increase	3,285,251	3,393,207	3,275,062
Twenty Year Increase	6,271,174	6,489,961	6,103,395

Table 5.4 presents our forecast sensitivity analysis for changes in commercial usage resulting from different assumptions of future economic activity. Higher sustained economic growth in the state could result in the growth of commercial natural gas usage, holding other factors constant. As seen in the table, under a high income scenario, commercial natural gas usage would increase by 22.7 percent over the long run forecast period and by approximately 22.4 percent under a low income scenario.

5.3: Industrial Baseline Forecast Sensitivity

Under our baseline forecast, we anticipate that industrial natural gas usage will grow at a relatively slow pace. Customer growth and usage in this class has been relatively constant over the recent past, and without the addition of new industries, it seems unlikely that there would be a significant relative shift in industrial usage. However, despite the relatively low percent growth for industrial use, it is a meaningful amount in absolute levels.

Table 5.5: Forecast Industrial Natural Gas Usage Under Different Price Scenarios

Year	Industrial Base Case (Mcf)	Industrial High Price Case (Mcf)	Industrial Low Price Case (Mcf)
2000	73,238,676	73,197,507	73,280,303
2001	73,636,131	73,553,767	73,719,514
2002	74,033,625	73,910,037	74,158,897
2003	74,431,150	74,266,303	74,598,436
2004	74,828,701	74,622,570	75,038,129
2005	75,226,290	74,978,844	75,477,994
2006	75,623,904	75,335,110	75,918,010
2007	76,021,556	75,691,388	76,358,194
2008	76,419,233	76,047,661	76,798,539
2009	76,816,949	76,403,938	77,239,049
2010	77,214,690	76,760,215	77,679,715
2011	77,612,470	77,116,500	78,120,555
2012	78,010,275	77,472,776	78,561,547
2013	78,408,118	77,829,065	79,002,711
2014	78,805,987	78,185,348	79,444,037
2015	79,203,895	78,541,636	79,885,529
2016	79,601,835	78,897,930	80,327,188
2017	79,999,800	79,254,219	80,769,008
2018	80,397,803	79,610,512	81,210,997
2019	80,795,832	79,966,805	81,653,146
2020	81,193,900	80,323,106	82,095,472
Ten Year Increase	3,976,015	3,562,708	4,399,411
Twenty Year Increase	7,955,225	7,125,599	8,815,169

Under our baseline forecast, we anticipate industrial usage to grow around 1 percent per year. For the short run forecast period (2000-2010), this would entail about a 5.4 percent increase or 4 Bcf. Over the long run forecast period we anticipate baseline growth of about 8 Bcf – or about an 11 percent increase. If prices increase, we forecast industrial natural gas usage growth would decrease slightly. Alternatively, should prices decrease, industrial natural gas usage would increase slightly.

We also considered the impact of changing economic conditions on industrial usage patterns in Alaska. Under most income scenarios, there are limited shifts in industrial usage over both the short run and longer run forecasting horizon. Given the relatively steady baseline forecast, changes in our differing income assumptions (as well as price) typically result in level shifts in usage.

Table 5.6: Forecast Industrial Natural Gas Usage Under Different Income Scenarios

Year	Industrial Base Case (Mcf)	Industrial High Income Case (Mcf)	Industrial Low Income Case (Mcf)
2000	73,238,676	73,271,847	73,205,269
2001	73,636,131	73,702,568	73,569,492
2002	74,033,625	74,133,416	73,933,615
2003	74,431,150	74,564,396	74,297,739
2004	74,828,701	74,995,497	74,661,862
2005	75,226,290	75,426,724	75,025,986
2006	75,623,904	75,858,085	75,390,109
2007	76,021,556	76,289,566	75,754,232
2008	76,419,233	76,721,175	76,118,356
2009	76,816,949	77,152,918	76,482,479
2010	77,214,690	77,584,783	76,846,603
2011	77,612,470	78,016,776	77,210,726
2012	78,010,275	78,448,903	77,574,849
2013	78,408,118	78,881,154	77,938,973
2014	78,805,987	79,313,533	78,303,096
2015	79,203,895	79,746,048	78,667,220
2016	79,601,835	80,178,686	79,031,343
2017	79,999,800	80,611,453	79,395,467
2018	80,397,803	81,044,357	79,759,590
2019	80,795,832	81,477,384	80,123,713
2020	81,193,900	81,910,542	80,487,837
Ten Year Increase	3,976,015	4,312,935	3,641,234
Twenty Year Increase	7,955,225	8,638,695	7,282,468

5.4: Electric Utility Baseline Forecast Sensitivity

We also examined a number of different scenarios for power generation. Our sensitivity analysis of power generation differed somewhat from the analysis done for retail natural gas usage for residential, commercial, and industrial customers. Our sensitivities were based upon changes that our economic drivers (price, income) had on electricity usage. From there we forecast the changes associated with gas fired power generation, and natural gas usage.

Table 5.7: Forecast Electric Utility Natural Gas Usage Under Different Price Scenarios

Year	Estimated Utility Base Case (Mcf)	Estimated Utility High Price Case (Mcf)	Estimated Utility Low Price Case (Mcf)
2000	35,656,886	35,569,901	35,569,901
2001	32,949,652	32,125,910	33,773,393
2002	33,655,948	32,814,549	34,497,347
2003	34,119,758	33,266,764	34,972,752
2004	34,899,977	34,027,477	35,772,476
2005	35,406,497	34,521,334	36,291,659
2006	35,330,693	34,447,426	36,213,961
2007	35,813,699	34,918,357	36,709,042
2008	36,248,792	35,342,572	37,155,012
2009	36,677,751	35,760,807	37,594,694
2010	37,031,714	36,105,921	37,957,507
2011	37,353,364	36,419,530	38,287,198
2012	37,759,602	36,815,612	38,703,592
2013	38,149,476	37,195,739	39,103,213
2014	38,529,726	37,566,483	39,492,969
2015	38,899,627	37,927,136	39,872,118
2016	39,272,923	38,291,100	40,254,746
2017	39,657,179	38,665,750	40,648,609
2018	40,036,768	39,035,849	41,037,687
2019	40,414,176	39,403,821	41,424,530
2020	40,790,982	39,771,208	41,810,757
Ten Year Increase	1,374,828	536,020	2,387,606
Twenty Year Increase	5,134,096	4,201,307	6,240,856

Table 5.7 presents the results from our electric utility baseline demand sensitivity analysis for changes in retail electricity prices. Under our baseline scenario, we

anticipate electric generation demand for natural gas to grow during the short run forecast period at approximately 3.9 percent. Over the longer run, we forecast generation use of natural gas to grow by about 14.4 percent.

If retail electricity prices increase by one percent, in real dollars, per year, we anticipate a slowing of electricity demand, and as a result, natural gas fired generation. The short run increase in power generation usage of natural gas falls to 1.51 percent under our high price scenario, and to 11.8 percent over the longer run forecast period.

Under a low retail electricity price scenario, we see moderate growth in the amount of natural gas fired generation. Over the short run period, this increase is about 6.7 percent, while over the longer run there is approximately at 17.5 percent increase in natural gas demanded by electric generators.

We have also examined the potential changes in natural gas fired power generation from shifts in our underlying economic output assumptions. If state income were to grow by one percent, in real dollars, per year, we forecast a relatively significant amount of gas fired power generation. Gas usage by power generation increase by about 14.5 percent over a ten year period, and 26.1 percent over the longer forecast period, assuming relatively strong economic growth.

Alternatively, if economic growth were to proceed on a relatively flat pace, we see power generation dipping in the short run, but rebounding slightly over the long run forecast period. In the short run, we forecast natural gas usage to fall by about 6.3 percent. Gas usage by power generation would increase over the longer run, but at a very moderate rate (3.2 percent).

Table 5.8: Forecast Electric Utility Natural Gas Usage Under Different Income Scenarios

Year	Estimated Utility Base Case (Mcf)	Estimated Utility High Income Case (Mcf)	Estimated Utility Low Income Case (Mcf)
2000	35,656,886	35,569,901	35,569,901
2001	32,949,652	36,244,617	29,654,687
2002	33,655,948	37,021,543	30,290,353
2003	34,119,758	37,531,734	30,707,782
2004	34,899,977	38,389,974	31,409,979
2005	35,406,497	38,947,146	31,865,847
2006	35,330,693	38,863,763	31,797,624
2007	35,813,699	39,395,069	32,232,329
2008	36,248,792	39,873,671	32,623,913
2009	36,677,751	40,345,526	33,009,975
2010	37,031,714	40,734,885	33,328,543
2011	37,353,364	41,088,701	33,618,028
2012	37,759,602	41,535,562	33,983,642
2013	38,149,476	41,964,424	34,334,529
2014	38,529,726	42,382,699	34,676,754
2015	38,899,627	42,789,590	35,009,664
2016	39,272,923	43,200,216	35,345,631
2017	39,657,179	43,622,897	35,691,462
2018	40,036,768	44,040,445	36,033,091
2019	40,414,176	44,455,593	36,372,758
2020	40,790,982	44,870,081	36,711,884
Ten Year Increase	1,374,828	5,164,984	-2,241,358
Twenty Year Increase	5,134,096	9,300,180	1,141,983

5.5: Total Usage Baseline Forecast Sensitivity

Under our baseline forecast, we estimate that total natural gas usage will increase from an annual level of approximately 155 Bcf (2000) to 182 Bcf (2020). The total increase in total natural gas usage over this period is 27 Bcf. For the year 2020, this increase represents a 17.6 percent increase from its 1999 levels under our baseline forecast.

If natural gas prices were to increase at an annual average rate of one percent, we estimate much lower levels of total natural gas usage. Our high price case

estimates annual use to grow from a level of 155 Bcf in 2000 to a level of 175 Bcf in 2020. Total usage over the forecast period, under our high natural gas price assumption, will grow by 20.8 Bcf over the forecast period. For the year 2020, this would represent a 13.4 percent increase in total natural gas usage. Under our high price assumption, usage would be approximately 6.5 Bcf below the baseline estimate.

If natural gas prices were to decrease at an annual average rate of one percent over the forecast period, we estimate higher total natural gas usage. Our low price forecast for total natural gas usage is 155 Bcf in 2000, and grows to a level of 191 Bcf by the year 2020. This represents an increase of 35.6 Bcf over 2000 total usage levels – or a 23 percent increase. Under our low price scenario, total natural gas usage will be approximately 8.4 Bcf above its baseline level.

Table 5.9: Forecast In-State Natural Gas Usage Under Different Price Scenarios

Year	Estimated Total [illegible] (Mcf)	Estimated Total High Price Case (Mcf)	Estimated Total Low Price Case (Mcf)
2000	154,980,358	154,718,943	155,070,588
2001	153,334,730	152,076,681	154,604,295
2002	155,061,745	153,490,926	156,661,503
2003	156,708,696	154,825,800	158,646,312
2004	158,745,146	156,535,791	161,043,895
2005	160,395,253	157,872,101	163,050,624
2006	161,350,851	158,539,575	164,344,576
2007	162,798,743	159,696,591	166,140,531
2008	164,220,859	160,832,230	167,914,047
2009	165,697,439	162,019,644	169,753,495
2010	167,157,253	163,187,419	171,588,512
2011	168,608,985	164,346,721	173,424,979
2012	170,139,507	165,586,218	175,347,131
2013	171,636,103	166,798,526	177,236,172
2014	173,113,957	167,997,914	179,108,184
2015	174,587,941	169,196,528	180,981,401
2016	176,083,191	170,416,609	182,884,641
2017	177,608,996	171,666,470	184,828,565
2018	179,144,660	172,926,720	186,791,058
2019	180,686,203	174,194,849	188,766,237
2020	182,232,010	175,470,138	190,751,225
Ten Year Increase	12,176,895	8,468,477	16,517,924
Twenty Year Increase	27,251,652	20,751,195	35,680,637

If state personal income were to increase at one percent per year, we forecast opportunities for total natural gas usage growth. Under our high income assumption, total natural gas usage will increase from a level of 155 Bcf in 2000 to 189 Bcf in 2020. This represents a 22.1 percent increase over the forecast period. Under the high income scenario, total natural gas usage would be approximately 6.9 Bcf above the baseline estimated growth levels.

If state personal income were to remain constant over the forecast period, total natural gas usage growth would grow by about 6.4 Bcf less than the baseline estimate. Under our low income assumption, total natural gas usage will grow from a level of 155 Bcf in 2000 to 176 Bcf in 2020. This represents a 13.5 percent increase over the forecast period.

Table 5.10: Forecast In-State Natural Gas Usage Under Different Income Scenarios

Year	Estimated Total Base Case (Mcf)	Estimated Total High Income Case (Mcf)	Estimated Total Low Income Case (Mcf)
2000	154,980,358	155,003,678	154,759,441
2001	153,334,730	156,852,618	150,080,509
2002	155,061,745	158,765,176	151,664,896
2003	156,708,696	160,576,250	153,040,912
2004	158,745,146	162,811,359	154,679,708
2005	160,395,253	164,635,020	156,060,819
2006	161,350,851	165,708,078	156,920,937
2007	162,798,743	167,331,417	158,292,685
2008	164,220,859	168,926,844	159,629,589
2009	165,697,439	170,579,124	160,967,656
2010	167,157,253	172,210,299	162,244,222
2011	168,608,985	173,833,176	163,497,824
2012	170,139,507	175,546,192	164,834,032
2013	171,636,103	177,226,405	166,162,283
2014	173,113,957	178,889,779	167,488,831
2015	174,587,941	180,551,375	168,813,176
2016	176,083,191	182,237,825	170,147,855
2017	177,608,996	183,959,360	171,499,851
2018	179,144,660	185,693,724	172,855,292
2019	180,686,203	187,437,174	174,216,611
2020	182,232,010	189,188,250	175,585,427
Ten Year Increase	12,176,895	17,206,621	7,484,781
Twenty Year Increase	27,251,652	34,184,572	20,825,986

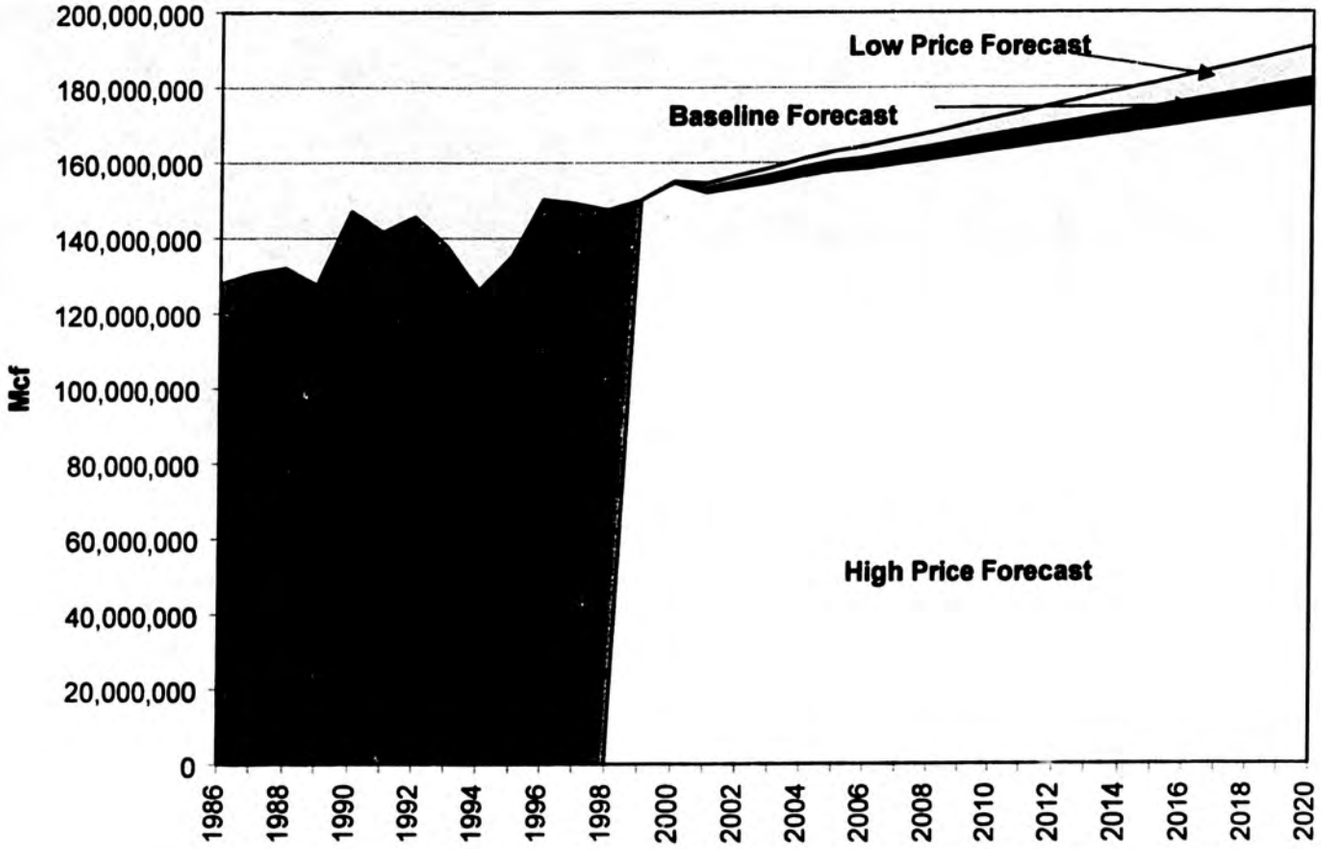

Figure 5.1: Forecast In-State Natural Gas Usage Under Different Price Scenarios

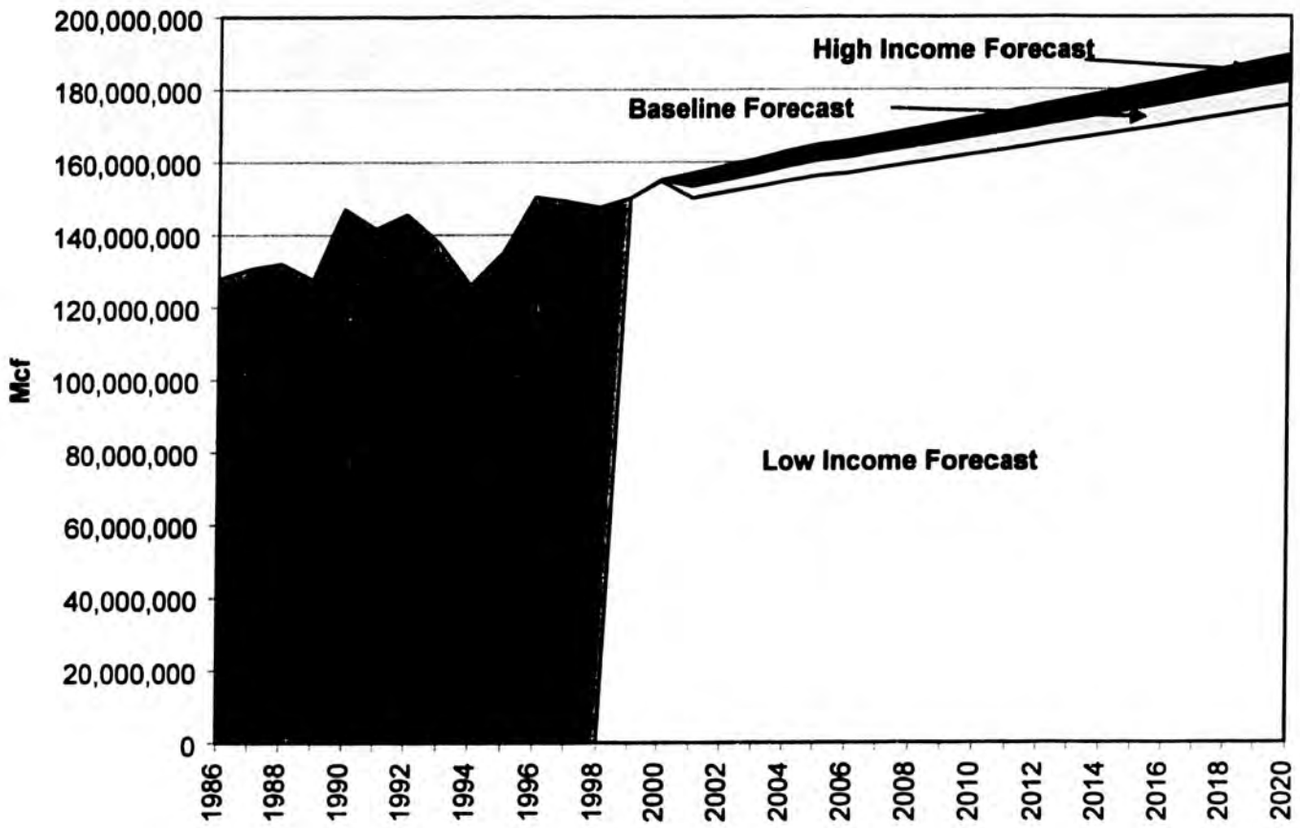

Figure 5.2: Forecast In-State Natural Gas Usage Under Different Income Scenarios

5.6: Conclusions

The sensitivity analysis for the baseline forecast was developed to examine a range of gas usage levels that could be realized under differing economic conditions. The main factor influencing these potential shifts in usage are the income and price elasticities of demand that have been estimated for each customer class. Overall, price impacts tend to have greater implications for usage relative to income impacts. This is particularly true for commercial customers that can exhibit price elasticities of –0.8 in the short run and –1.8 in the long run.

Sensitivity ranges (i.e, high, low) for price and income were developed from a fixed range over longer run 10 year averages. A given symmetrical range around this historic averages were developed for comparison purposes. The approach

is similar to that developed by ISER in its Alaska forecast. However, our ranges are admittedly smaller, and more conservation than some of the outer ranges considered in the ISER analyses. Our sensitivity analysis is designed to answer a "what if" question, i.e., explore changes in the dependent variable due to lower or higher levels of the independent variables. In that sense, the levels of the independent variables represent not so much a "forecasted" values, but rather certain discrete levels, which, in our view, correspond to a qualitative label of "high" and "low".

There are a number of other sensitivities to in-state usage that can be considered. These sensitivities include examining the implications of shifts in natural gas usage of large individual users. Currently, there are two significant industrial users of natural gas in Alaska: the LNG facility owned by Phillips and Marathon in Kenai, and the Agrium, Inc. ammonia-urea facility, located in neighboring Nikiski. Combined, these facilities account for close to 130 Bcf per year in natural gas usage. Expansions or closure of these facilities could have significant implications for in-state usage. The role that these facilities play in determining in-state usage trends is examined in greater detail in Chapter 7.

CHAPTER 6: EXPANDED RESIDENTIAL SERVICE

6.1: Regional Analysis of Expanded Residential Service Opportunities

In terms of the residential market, we examined two potential opportunities for increased natural gas usage:

(1) Expanding coverage of natural gas service to those remote areas that currently have no existing or proposed gas service.

(2) Increasing natural gas market penetration rates in areas that already have gas service.

In order to analyze these potential opportunities we used a geographic information system (GIS) to combine demographic geo-referenced information with information on existing and proposed natural gas service areas. This approach allowed us to establish a spatial framework for residential natural gas service in Alaska, which is required for the analysis.

According the 2000 U.S. Census of Population and Housing, Alaska has a population of 580 thousand people, which make up 205 thousand households. Approximately two thirds of the population reside in the Southcentral region. The Interior and the Southeast region account for 11 percent each, while the Far North region has only 4 percent. Anchorage, located in the Southcentral region, is the only large city in the state, it alone accounts for 45 percent of the total Alaskan population. Together, the cities of Juneau and Fairbanks, with populations of about 30,000 each, account for 10 percent of statewide population.

Figure 6.1 shows the geographic distribution of settlements within Alaska according to size. The distribution of population in the state is very uneven, with majority of the population concentrated in three major urban clusters: Anchorage; Juneau; and Fairbanks. The size of the dots in Figure 6.1 represents the size of the settlements throughout the state. Very small dots, for instance, represent settlements with less than 500 households (conventionally, population is measured in number of people; however, we are using number of households because a household represents a gas service customer). As can be seen on the map, Alaska has three major areas with population greater than 4,500 households: Juneau in the Southeast, Anchorage in the Southcentral area, and Fairbanks in Interior Alaska. There are a considerable number of settlements in Alaska with fewer than 500 households.

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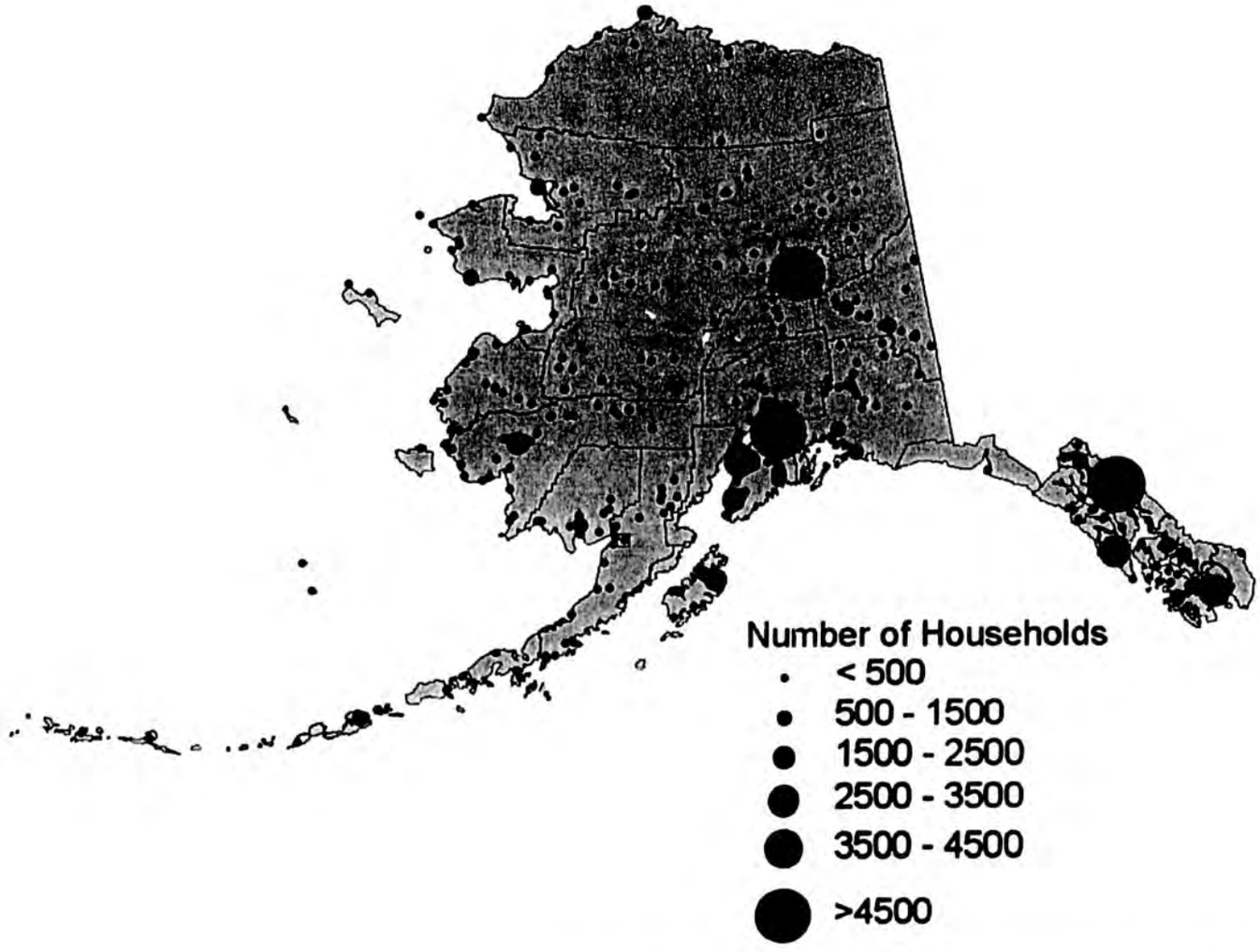

Figure 6.1 Geographical Distribution of Settlements in Alaska

Our next step after identifying settlement distributions and locations throughout the state was to identify those settlements that are currently being served by natural gas distribution systems. In addition to identifying current systems, we also identified those areas that have plans for future services. This information was collected from the Regulatory Commission of Alaska (RCA). The settlements with existing or proposed natural gas services are provided in Table 6.1. The geographic distribution of these settlements and their gas service status is presented in Figure 6.2.

Table 6.1 Settlements with Existing or Proposed Natural Gas Service

Community	Region	NG Provider	Population	Households
Angoon	Southeast	AIGC	572	184
Cordova	Southcentral	AIGC	2,454	958
Craig	Southeast	AIGC	1,397	523
Haines	Southeast	AIGC	1,811	752
Juneau	Southeast	AIGC	30,711	11,543
Kake	Southeast	AIGC	710	246
Ketchikan	Southeast	AIGC	7,922	3,197
Klawock	Southeast	AIGC	854	313
Klukwan	Southeast	AIGC	139	44
Kodiak	Southwest	AIGC	6,334	1,996
Metlakatla	Southeast	AIGC	1,375	469
Petersburg	Southeast	AIGC	3,224	1,240
Sitka	Southeast	AIGC	8,835	3,278
Skagway	Southeast	AIGC	862	401
Valdez	Southcentral	AIGC	4,036	1,494
Wrangell	Southeast	AIGC	2,308	907
Yakutat	Southeast	AIGC	680	261
Barrow	Far North	BUECI	4,581	1,371
Anchorage	Southcentral	ENSTAR	260,283	94,822
Big Lake	Southcentral	ENSTAR	2,635	971
Houston	Southcentral	ENSTAR	1,202	445
Kenai	Southcentral	ENSTAR	6,942	2,622
Nikiski	Southcentral	ENSTAR	4,327	1,514
Palmer	Southcentral	ENSTAR	4,533	1,472
Soldotna	Southcentral	ENSTAR	3,759	1,465
Sterling	Southcentral	ENSTAR	4,705	1,676
Wasilla	Southcentral	ENSTAR	5,469	1,979
Whittier	Southcentral	ENSTAR	182	86
Fairbanks	Interior	FNG	30,224	11,075
Prudhoe Bay	Far North	NORGASCO	5	1

Source: Regulatory Commission of Alaska and 2000 U.S. Census of Population and Housing.
AIGC = Alaska Interstate Gas Company.
BUECI = Barrow Utilities & Electric Cooperative, Incorporated.
FNG = Fairbanks Natural Gas, LLC.
Note: Not all the settlements receive residential gas service. AIGC is planning to provide gas service.

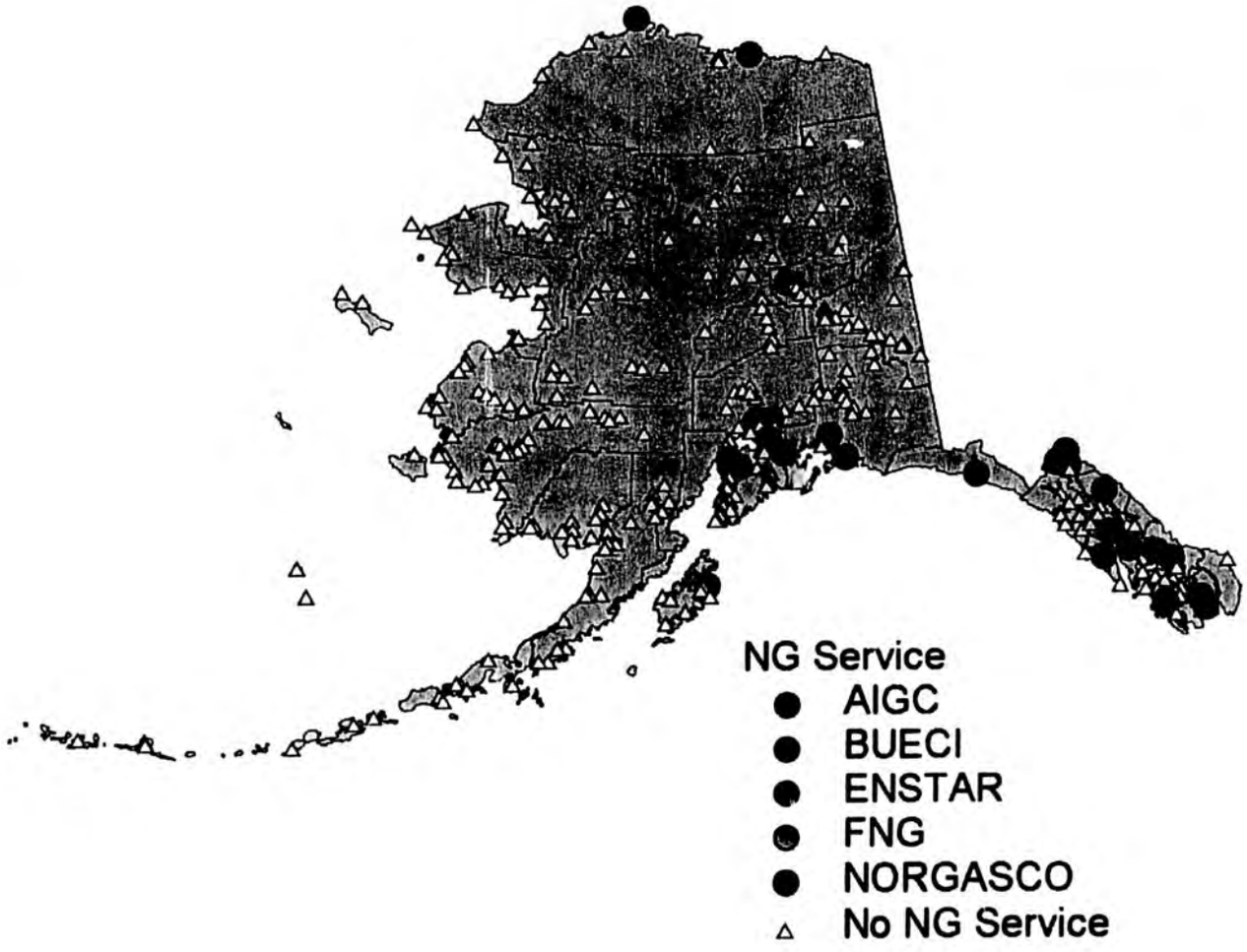

Figure 6.2: Geographical Distribution of Natural Gas Service in Alaska

Figure 6.2 shows that there are a large number of settlements that are currently not listed as having gas service. Areas covered by existing or proposed systems are restricted to Southcentral and Southeastern Alaska. Based upon publicly available information, there are other small pockets in northern Alaska and one in Interior Alaska.

Table 6.2 shows the distribution of Alaska population and households. The top portion of the table presents the numbers for each of the series, while the bottom half of the table shows the relative distribution. An important statistic reported in this table is that 30 percent of Alaska's population and 28 percent of its households are not being served by natural gas.

Table 6.2 Distribution of Alaska Population and Households by Existing or Proposed Natural Gas Service

NG Utility	Population	Households
No NG service	176,272	57,262
AIGC	74,224	27,806
BUECI	4,581	1,371
ENSTAR	294,037	107,052
FNG	30,224	11,075
NORGASCO	5	1
AK Total	579,343	204,567

NG Utility	Population	Households
No NG service	30.4%	28.0%
AIGC	12.8%	13.6%
BUECI	0.8%	0.7%
ENSTAR	50.8%	52.3%
FNG	5.2%	5.4%
NORGASCO	0.0%	0.0%

Alternatively, some 72 percent of Alaska's households currently reside in places with natural gas service. As seen in Table 6.3, 52 percent of all households in Alaska live within the Enstar's service zone. Enstar, the state's largest local distribution company (LDC), provides natural gas to residential and commercial customers in Anchorage, Big Lake, Chugiak, Eagle River, Eklutna, Girdwood, Houston, Kenai, Knik, Nikiski, Palmer, Peters Creek, Soldotna, Sterling, Wasilla, and Whittier. Enstar contemplates expanding gas distribution service to Ninilchik, Anchor Point, Homer and other lower Kenai Peninsula communities.

Table 6.3: Proposed Kenai Kachemak Pipeline Project

Community	Region	NG Planned Provider	Population	Households
Anchor Pt	Southcentral	ENSTAR	1,845	711
Clam Gulch	Southcentral	ENSTAR	173	67
Homer	Southcentral	ENSTAR	3,946	1,599
Kasilof	Southcentral	ENSTAR	471	180
Ninilchik	Southcentral	ENSTAR	772	320

Unocal Alaska and Marathon Oil Company have formed the Kenai Kachmak Pipeline, LLC and recently announced an open season for a 58-mile gas transmission pipeline between Kenai and Anchor Point near the southern end of the Kenai Peninsula. The KKPL initially would transport gas from new fields currently under exploration in the southern Kenai Peninsula into the existing pipeline distribution system operated by Enstar and Kenai-Nikiski Pipeline. Enstar eventually may construct a distribution segment between Anchor Point and Homer. The KKPL is expected to begin operation in 2004. Pipeline capacity is still unknown and will depend on exploration success. When all phases are completed, gas service could become available to the communities of Ninilchik, Anchor Point, Clam Gulch, Kasilof, and Homer. Collectively these southern Kenai Peninsula communities contain approximately 2,900 occupied households, representing about a three-percent addition to the existing 105,000 Enstar customer base. This would imply about 500 to 600 million cubic feet per year of potential residential gas service, not including commercial and electric power generation potential.

Alaska Interstate Gas Company (AICG) has proposed to develop a gas service, which would serve places containing 14 percent of all Alaska households, primarily in Southeast. According to the RCA 2000 Annual Report, AIGC was scheduled to begin serving Juneau, Ketchikan, and Sitka on July 1, 2001; Cordova, Craig, Klawock, Kodiak, Petersburg, Valdez, and Wrangell by July 1, 2005; and Angoon, Haines, Kake, Klukwan, Metlakatla, Skagway, and Yakutat by July 1, 2010. However it is important to point out that, except for Valdez, these relatively small and remote communities are located apart from the road- or rail-

connected energy belt and apart from known natural gas reserves or gas transmission lines.

Table 6.4 examines the distribution of settlement size and number of households with and without natural gas service. According to the information available to our study, there are some 297 settlements with fewer than 500 households that do not have access to natural gas service. The total number of households that live in these small, non-gas service areas is approximately 25,000. There are 26 settlements in Alaska that range between 500 and 2,400 households that do not have access to natural gas service. These places account for approximately 29,000 households. There is one settlement in Alaska that has a total of 4,100 households that is currently listed as not having access to natural gas service. This is an area around the campus of University of Alaska at Fairbanks, a census designated place (CDP), College, located just outside the corporate limits of Fairbanks.

Table 6.4: Distribution of Alaska Households by Settlement Size and Existing or Proposed Natural Gas Service

	Number of Places			Number of Households		
Settlement Size (000 households)	With NG Service	Without NG Service	All	With NG Service	Without NG Service	All
<0.5	10	287	297	2,450	24,599	27,049
0.5-1.4	10	19	29	11,153	15,199	26,352
1.5-2.4	4	7	11	7,165	13,360	20,525
2.5-3.4	3	0	3	9,097	0	9,097
3.5-4.4	0	1	1	0	4,104	4,104
> 4.5	3	0	3	117,440	0	117,440
All	30	314	344	147,305	57,262	204,567

Table 6.5. Cumulative Distribution of Alaska Households by Settlement Size and Existing or Proposed Natural Gas Service

	Number of Places			Number of Households			Percent w/o Gas Service	
Settlement Size (000 households)	With NG	Without NG	All	With NG	Without NG	All	Settlements	Households
<0.5	10	287	297	2,450	24,599	27,049	96.6%	90.9%
<1.5	20	306	326	13,603	39,798	53,401	93.9%	74.5%
<2.5	24	313	337	20,768	53,158	73,926	92.9%	71.9%
<3.5	27	313	340	29,865	53,158	83,023	92.1%	64.0%
<4.5	27	314	341	29,865	57,262	87,127	92.1%	65.7%
All	30	314	344	147,305	57,262	204,567	91.3%	28.0%

The next step in our analysis was to estimate the amount of natural gas that could be used if the identified unserved areas of Alaska were offered access to natural gas service. This estimate has been provided in Table 6.6. Our analysis of new potential residential in-state demand has been conducted in a "boundary" fashion. That is, we have identified the outer range of new residential growth possibilities. The outer range is estimated assuming that every household will use natural gas at current average consumption rate. The first two lines in Table 6.6 identify existing residential consumption and customers. Line 3 through line 5 estimate those households that currently have access to natural gas service, or have plans for service in the near future.

Line 6 and line 7, however, estimate those households that either do not have access to natural gas service or do not utilize their ability to access natural gas service. Line 7 divided by line 2, therefore, would give the current percent of customers not taking natural gas service (not shown). Lines 8 through 11 estimate natural gas usage (based on the observed average consumption per customer) for the various types of residential households: those with natural gas service; those with proposed natural gas service; and potential usage for those that currently do not have residential natural gas service.

Line 10 shows the potential residential gas usage levels in areas without access to natural gas if service were extended to these areas. The largest concentration of these volumes, seen as a percentage in the far right hand columns, is in the Southcentral region of Alaska. Nearly 50 percent of expanded service usage volumes could come from this region. The next two largest opportunities for regional development appear to be in the Southwest region (21 percent) and the Interior region (19 percent).

We also conducted a number of additional analyses that estimated potential residential usage if the penetration rates of existing, proposed, and potential regions were expanded to 100 percent. This estimate would reflect the maximum coverage of gas usage in Alaska if all households were served. These estimates have been provided on line 12 through line 16. Line 14, for instance, estimates total gas usage if existing and proposed regions expanded their penetration rates to 100 percent.

Table 6.6: Summary Analysis of Potential Residential In-State Natural Gas Usage

			Levels						Percents of Total					
Line No.	Calculation by Line No.		Far North	Interior	South Central	South East	South West	Total	Far North	Interior	South Central	South East	South West	Total
1	EIA	1999 Residential NG Consumption (Mcf)	215,126	0	17,418,738	0	0	17,633,864	1.2%	0.0%	98.8%	0.0%	0.0%	100.0%
2	EIA	1999 Number of Residential Customers	1,109	0	87,815	0	0	88,924	1.2%	0.0%	98.8%	0.0%	0.0%	100.0%
3	RCA, Census	Number of Households with Existing (as of 12/31/1999) Access to NG	1,371	11,075	107,052	0	0	119,498	1.1%	9.3%	89.6%	0.0%	0.0%	100.0%
4	RCA, Census	Number of Households with Proposed Access to NG (AIGS service area) [a]	0	0	2,452	23,358	1,996	27,806	0.0%	0.0%	8.8%	84.0%	7.2%	100.0%
5	3 + 4	Number of Households with Existing or Proposed Access to NG	1,371	11,075	109,504	23,358	1,996	147,304	0.9%	7.5%	74.3%	15.9%	1.4%	100.0%
6	RCA, Census	Number of Households without Existing or Proposed Access to NG	4,550	11,456	27,101	1,794	12,361	57,262	7.9%	20.0%	47.3%	3.1%	21.6%	100.0%
7	5 - 2	Number of Households not Using Existing Access to NG	262	11,075	19,237	0	0	30,574	0.9%	36.2%	62.9%	0.0%	0.0%	100.0%
8	4 x [1 / 2] x [2 / 3]	Expected Residential NG Consumption in Areas with Proposed Access to NG (MCF)	0	0	398,972	3,446,776	294,536	4,140,284	0.0%	0.0%	9.6%	83.2%	7.1%	100.0%
9	1 + 8	Expected Residential NG Consumption in Areas with Existing or Proposed Access to NG (Mcf)	215,126	0	17,817,710	3,446,776	294,536	21,774,148	1.0%	0.0%	81.8%	15.8%	1.4%	100.0%
10	6 x [1 / 2] x [2 / 3]	Expected Residential NG Consumption in Areas without Existing or Proposed Access to NG (Mcf)	713,948	1,690,482	4,409,681	264,728	1,824,026	8,902,866	8.0%	19.0%	49.5%	3.0%	20.5%	100.0%
11	9 + 10	Expected Residential NG Consumption in Alaska Assuming Universal Access to NG (Mcf)	929,074	1,690,482	22,227,391	3,711,504	2,118,562	30,677,013	3.0%	5.5%	72.5%	12.1%	6.9%	100.0%
12	3 x [1 / 2]	Potential Residential NG Consumption in Areas with Existing Access to NG Assuming 100% Market Saturation (Mcf)	265,949	2,196,173	21,234,536	0	0	23,696,657	1.1%	9.3%	89.6%	0.0%	0.0%	100.0%
13	4 x [1 / 2]	Potential Residential NG Consumption in Areas with Proposed Access to NG Assuming 100% Market Saturation (Mcf)	0	0	486,372	4,631,891	395,807	5,514,070	0.0%	0.0%	8.8%	84.0%	7.2%	100.0%
14	12 + 13	Potential Residential NG Consumption in Areas with Existing or Proposed Access to NG Assuming 100% Market Saturation (Mcf)	265,949	2,196,173	21,720,907	4,631,891	395,807	29,210,727	0.9%	7.5%	74.4%	15.9%	1.4%	100.0%
15	6 x [1 / 2]	Potential Residential NG Consumption in Areas without Existing or Proposed Access to NG Assuming 100% Market Saturation (Mcf)	882,618	2,271,725	5,375,679	355,750	2,451,186	11,336,958	7.8%	20.0%	47.4%	3.1%	21.6%	100.0%
16	14 + 15	Potential Residential NG Consumption in Alaska Assuming Universal Access and 100% Market Saturation (Mcf)	1,148,567	4,467,897	27,096,586	4,987,642	2,846,993	40,547,685	2.8%	11.0%	66.8%	12.3%	7.0%	100.0%

[a] Places with households include Cordova and Valdez (Southcentral); Angoon, Craig, Haines, Juneau, Kake, Ketchikan, Klawock, Klukwan, Metlakatla, Petersburg, Sitka, Wrangell and Yakutat (Southeast); and Kodiak (Southwest).

Currently, the Southcentral region dominates both the total number of households with access to natural gas service, and, as a result, total residential natural gas usage. Table 6.6, line 3 shows that this region currently accounts for close to 90 percent of all households with access to natural gas service. Line 4, however, reveals that new (proposed) service opportunities are being created in other regions. These new expansion plans are primarily in the Southeastern region (84 percent of new service proposed for this area).

Another focus of the analysis is to identify households in existing natural gas service areas that do not receive service. Overall, Alaska has an approximate residential natural gas service penetration rate of 80 percent, while the Southcentral region has a somewhat higher average residential penetration rate of 82 percent. We have identified some 11,075 households in the Interior region that are within a defined natural gas utility service area. This region includes the Fairbanks North Star Borough and is examined in greater detail at the end of this chapter.

Lines 8 through 11 of Table 6.6 estimates the natural gas usage associated with households in different Alaska regions. A large portion of the estimated natural gas usage is in the Southcentral region. In addition to identifying the existing distribution of regional natural gas usage, we have also identified new opportunities for natural gas service volumes that are presented on line 10. We have identified a potential for 8.9 Bcf if service were expanded to unserved areas of Alaska. This increased usage assumes that the currently unserved areas achieve a penetration rate comparable to the state-wide average.

As indicated above, close to 50 percent of our identified new sources of expanded residential natural gas usage are located in the Southcentral region. Approximately 40 percent of those potential expanded service usage is in the Interior (19.0 percent) and Southwest (20.5 percent) regions of the state. The remaining new expanded service usage opportunities are in the Far North (8 percent) and Southeast (3 percent) regions. Line 11 sums the existing gas usage and the new potential expansions, to estimate a new in-state residential natural gas usage level based upon 1999 average usage trends and levels.

The analysis also considers opportunities for expanding gas usage in areas that currently have natural gas service coverage through increasing the market penetration rates. Line 12 and line 13, for instance, estimate the levels of gas usage that could occur in existing and proposed service areas if service penetration rates were increased from their existing levels to 100 percent. These opportunities from service expansion have been summed on line 14. We estimate approximately 7.4 (29.2-21.8) Bcf of additional usage opportunities if service penetration levels were increased to their maximum.

Approximately 74 percent of the expanded service opportunities are located in Southcentral Alaska. Close to 16 percent of the expanded service opportunities

are located in Southeast Alaska. The total service expansion opportunities are much less in the remaining areas, primarily because these areas currently have no to little service to expand upon.

Line 15 examines new residential usage opportunities in currently unserved areas from a different perspective. Here, we estimate total usage opportunities if service were expanded in these regions, and penetration rates reached 100 percent. This estimate, therefore, is higher than that presented in line 10. We estimate the possibility of 11.3 Bcf of increased residential usage in currently unserved areas if 100 percent penetration rates were achieved.

Line 14 and line 15 can be compared to examine new residential natural gas usage opportunities in existing areas (line 14) with new growth opportunities in unserved areas (line 15). Both estimates assume 100 percent penetration, so the comparison, as well as the sum (line 16), represent the boundary, or outermost opportunities for expanded residential natural gas usage. Comparing lines 14 and 15, we see that increasing market penetration rates in areas with existing or proposed service (7.5 Bcf per year) yields slightly less additional consumption than expanding service into the unserved regions (8.9 Bcf per year).

We have presented three figures to try to simply the analysis presented in Table 6.6. Figure 6.3 presents a pie chart showing the break-out of the estimated usage potentials in unserved areas, versus the estimated usage in existing LDC service territories for the state. Usage in unserved areas would represent approximately 29 percent of the total (or 8.9 Bcf per year). The remaining usage is associated with areas that already have natural gas service opportunities. This figure is based upon the estimates that assumed new areas will achieve penetration rates comparable to the statewide average.

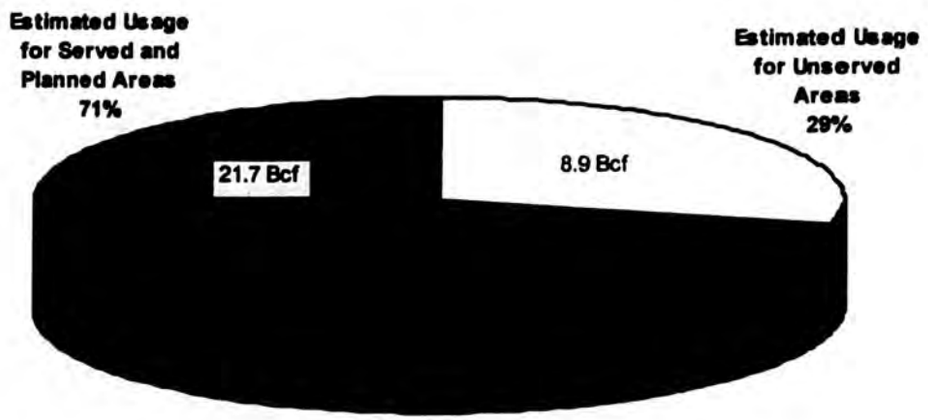

Figure 6.3: Estimated Usage in Served and Unserved Areas Assuming Statewide Average Penetration Rates

FIgure 6.4 is a similar representation, but shows total usage, and percentages, assuming 100 percent penetration of both unserved and served areas. Of the maximum total residential usage potential, usage in unserved areas represents about 28 percent of total, or 11.3 Bcf. Usage in areas currently served by LDCs increases to 29.2 Bcf, or 72 percent of total.

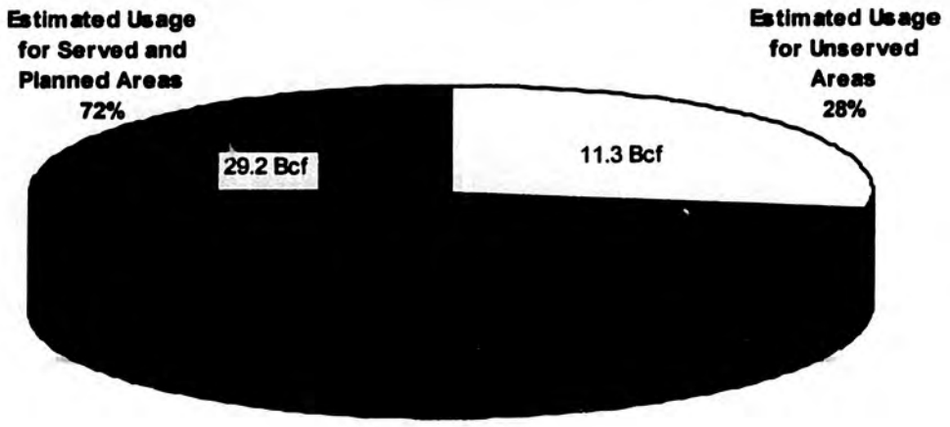

Figure 6.4: Estimated Usage in Served and Unserved Areas Assuming 100 Percent Penetration Rates

The last figure (Figure 6.5) we have presented compares the estimated usage in unserved areas with the estimated usage from expanding the statewide average penetration level from roughly 80 to 100 percent. As seen in the figure, the percentages and levels are roughly the same. Estimated usage in unserved areas could be approximately 8.9 Bcf while usage from expansion of current LDC penetration rates is 7.4 Bcf.

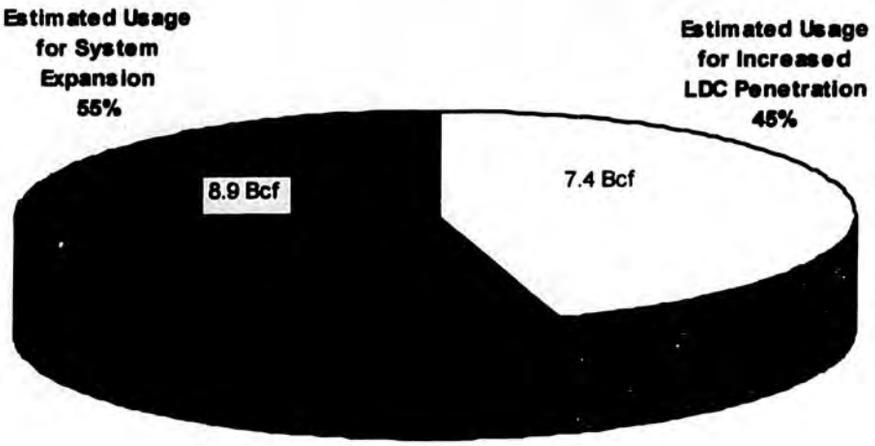

Figure 6.5: Comparison of Estimated Usage in Unserved Areas versus Increased Penetration Rates in Existing LDC Areas

The results of our detailed analysis reveal some interesting insights into new residential natural gas usage opportunities. Our analysis supports the two major conclusions:

(1) On a regional basis, Southcentral Alaska has the largest opportunities for expanding residential natural gas service beyond its current LDC service areas;

(2) On a statewide basis, potential growth in residential natural gas usage associated with increasing the penetration rates of existing local distribution systems almost equals potential growth associated with extending the service into remote areas.

6.2: Residential Proximity Analysis to Existing and Proposed Natural Gas Infrastructure

We also conducted an alternative analysis that examined the possibilities of expanding natural gas service to customers living within proximity to existing and proposed natural gas infrastructure of the state. The two sets of natural gas infrastructure that we examined included:

(1) Expansions to the existing natural gas utilities (LDCs);

(2) Service expansion opportunities in geographic proximity to the Alaska natural gas transportation pipeline.

In both cases, for any given area, physical proximity to sources of natural gas infrastructure becomes a critical factor in determining costs of the provision of natural gas. Our geographic proximity analysis proceeded along the following lines:

1. We used the geographic boundary files developed by the U.S. Census Bureau to produce a map of Alaskan settlements (cities, towns, villages, census designated places, etc.) in their administrative (or census-designated) boundaries.

2. We used the newly released STF1 file for Alaska from the 2000 U.S. Census of Population and Housing to identify the number of occupied households in each settlement.

3. We used information contained in the 2000 Annual Report of the Alaska Regulatory Commission to identify settlements with either existing or proposed natural gas service. As a result, we have classified all the settlement in Alaska as either having existing or proposed natural service (EPNGS) or as not having existing or proposed service (NOEPNG). These areas have been presented earlier in Figure 6.2.

4. For every EPNGS settlement we created four proximity zones in five-mile increments. For instance, a five-mile proximity zone is created by extending administrative borders of a settlement outward by five miles. A 10-mile zone, however, covers a territory around a settlement that is between 5 and 10 miles of its existing geographic definition. Thus, adding up the opportunities in each five-mile increment will result in the cumulative total new natural gas usage opportunities.

5. When buffers in each distance range had multiple EPNGS settlements, we merged each of these settlements into a single proximity zone. Given the concentration of many existing service areas, we created four proximity zones for Alaska. Thus, a five-mile Alaska zone covers all the territory

within five miles of the EPNGS area. These concentrations have been presented in Figure 6.6. The upper left hand side of this figure shows the state-wide concentrations. The upper right hand side is a zoomed-in view of the northern Alaska concentrations, while the lower part of the figure provides a zoomed-in view of the southern Alaska region.

6. Following the description of the proposed Alaska Highway Route (AHR) for the natural gas transportation pipeline, we developed a digital boundary for the proposed pipeline route (this region will be labeled "AHR").[1]

7. Similar to the procedure described above for EPNGS buffers, we developed four proximity zones in the increment of five miles around the AHR. These boundaries have been presented in Figure 6.7.

8. We overlaid boundaries of NOEPNGS settlements separately with EPNGS zones and with AHR zones. Thus, every NOEPNGS settlement was classified according to proximity (within 5 miles, within 10 miles, within 15 miles, within 20 miles, and beyond 20 miles) to the examined natural gas infrastructure.

9. Finally, we aggregated the number of occupied households living in NOEPNGS settlements by region and by proximity to sources of natural gas supply. Tables 6.7, 6.8, and 6.9 present the results of our analysis. We have also estimated usage associated with these household estimates and have presented them in Tables 6.10 and 6.11.

[1]For purposes of our analysis, the AHR includes spurs into the Southcentral region. These spurs, and our mapping of the AHR, is based upon the presentation provided by Alaska DNR Commissioner Pat Pourchot which is available on the Alaska Highway Natural Gas Council homepage: www.gov.state.ak.us/gascouncil

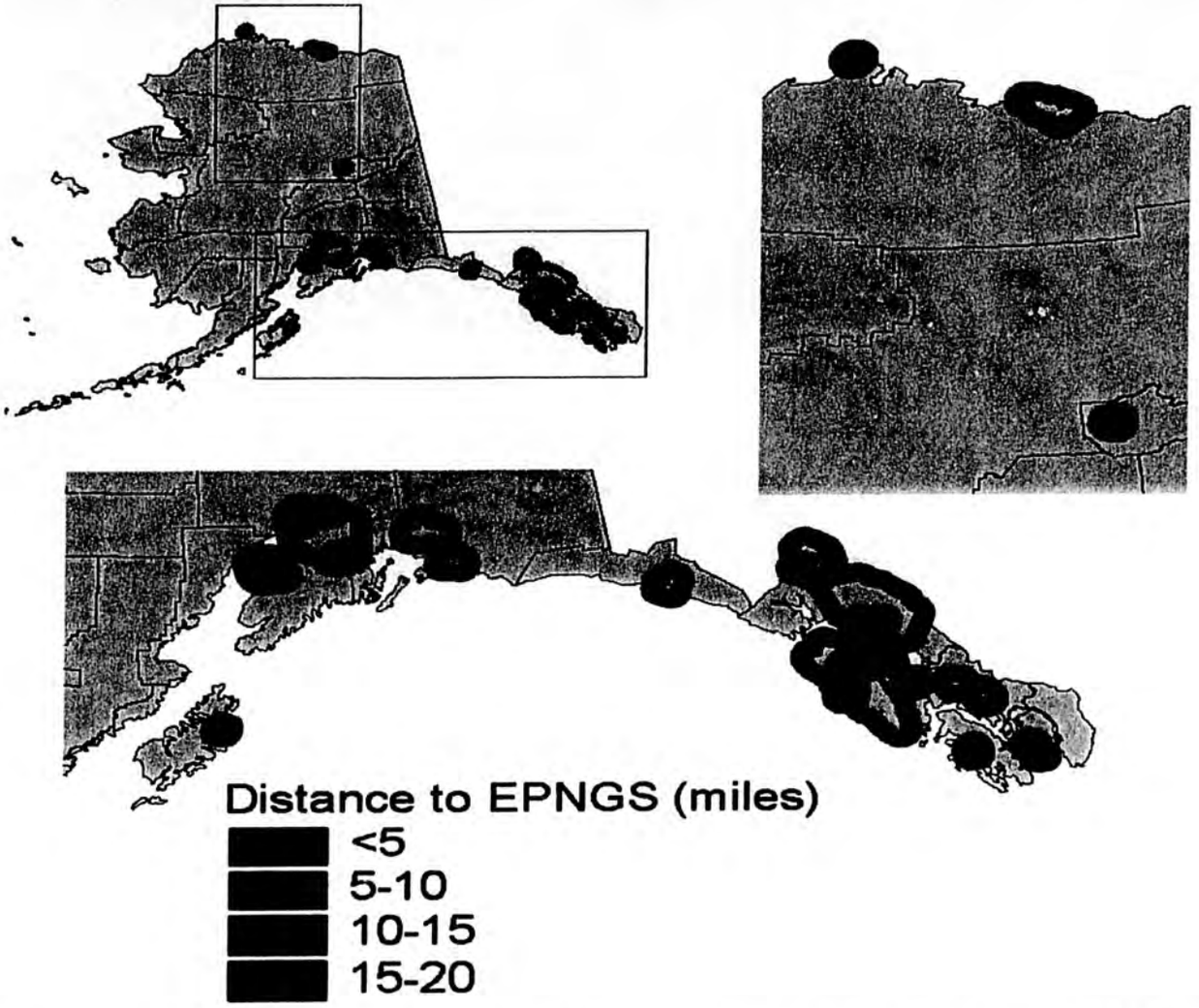

Figure 6.6: Proximity Zones around Existing and Proposed Natural Gas Systems in Alaska (EPNGS)

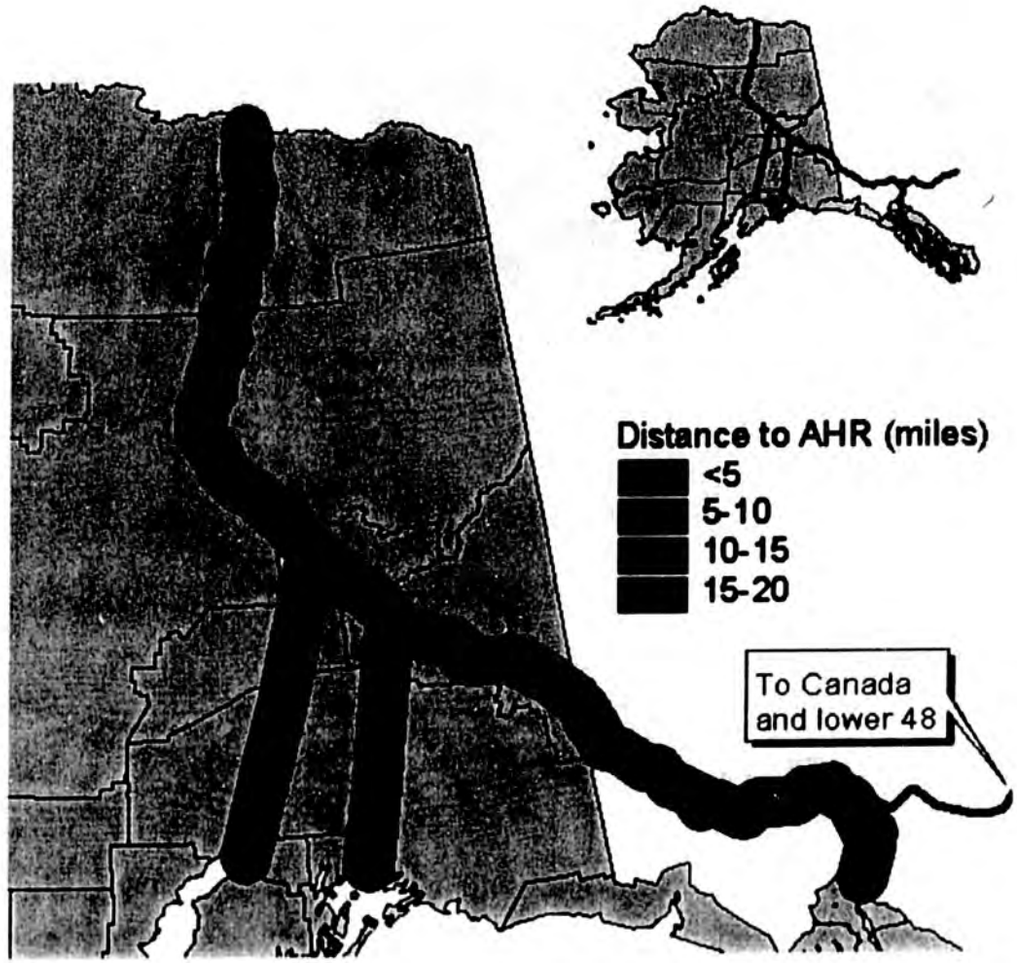

Figure 6.7: Proximity Zones Areas Around the Proposed Alaska Highway Route (AHR)

Table 6.7 reports the number of households in settlements without natural gas service (NOEPNGS), while Table 6.8 shows the frequency distribution of households within each region and for Alaska as a whole. In both tables, statistics for the proximity zones close to existing natural gas systems (EPNGS) are provided in the columns while the statistics for proximity zones close to Alaska Highway Route (AHR) are presented in the rows. These tables should be read in a cumulative and not incremental fashion.

For instance, Table 6.7 shows that in the lower most corner of the table, there are 57,262 households (intersection of "Row Total" and "Column Total") living in settlements that have no existing or proposed natural gas service. Of that amount, some 26,220 households do not live within 20 miles of either an existing natural gas distribution system (EPNGS) or the Alaska Highway Route (AHR) pipeline. These households (26,220) amount to some 45.8 percent of total non-served Alaska households. Thus, close to half of the households in Alaska reside within settlements that are not within 20 miles of neither the proposed major transportation route, nor an existing local distribution system.

On the other extreme, we have provided estimates of those households that are close to existing LDC systems and the AHR. Consider the bottom most section of Table 6.7 that has the Alaska totals. In the upper row (within 5 miles) we estimate that there are 10,325 households that are in settlements that are within both 5 miles of existing LDC systems (EPNGS) and the proposed highway route (AHR). Thus, some 18 percent of the non-served households reside in settlements that are within 5 miles of both the existing LDC systems and the AHR. The percentage can be found in the same cell on Table 6.8

We can also examine the geographic distribution of households within areas served by LDC systems and AHR separately. Consider the same section of Table 6.7 (the Alaska total section). We find that there are 11,934 households that are in settlements within 10 miles of the AHR and within 5 miles of an existing LDC system, representing 20.8 percent of the total unserved households in Alaska (Table 6.7 for cumulative percent). Moving to the right hand side of this section of bottom of Table 6.7 we find that there are 12,490 households that reside within 5 miles of the AHR and within 20 miles of an existing LDC system. This represents 21.8 percent of the unserved households (Table 6.7).

Table 6.9 presents summary of the major mileage categories and the households that fall into the proximity zones we have identified. Estimates for each region are provided in this table. In addition, to the right of the Alaska total is the sum of the households in the combined Interior and Southcentral regions.

We conclude from the geographic proximity analysis that approximately 19,000 occupied households, representing the potential for 3.8 Bcf per year of natural gas usage, are located within 20 miles of the proposed AHR and an existing gas

service area. These households are located primarily in the Southcentral and Interior regions and represent about one-third of all occupied households, statewide that currently are not served by natural gas distribution systems.

Table 6.7: Distribution of Alaskan Households without Existing or Proposed Access to Natural Gas Service by Proximity to Potential Sources of Natural Gas Supply

Region		Distance to EPNGS Settlements					
		Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Row Total
	Distance to AHR						
Far North	Within 5 miles	0	0	0	0	13	13
	Within 10 miles	0	0	0	0	13	13
	Within 15 miles	0	0	0	0	13	13
	Within 20 miles	0	0	0	0	25	25
	Beyond 20 miles	0	0	0	0	4,525	4,525
	Column Total	0	0	0	0	4,550	4,550
Interior	Within 5 miles	5,555	5,732	7,403	7,720	1,761	9,481
	Within 10 miles	5,555	5,732	7,403	7,939	1,761	9,700
	Within 15 miles	5,555	5,732	7,403	7,939	1,787	9,726
	Within 20 miles	5,555	5,732	7,403	7,939	1,822	9,761
	Beyond 20 miles	0	0	0	0	1,695	1,695
	Column Total	5,555	5,732	7,403	7,939	3,517	11,456
South Central	Within 5 miles	4,770	4,770	4,770	4,770	1,400	6,170
	Within 10 miles	6,379	6,417	6,417	6,417	1,409	7,826
	Within 15 miles	9,259	9,297	9,297	9,297	1,771	11,068
	Within 20 miles	11,162	11,219	11,219	11,219	2,150	13,369
	Beyond 20 miles	4,849	5,474	5,561	5,778	7,954	13,732
	Column Total	16,011	16,693	16,780	16,997	10,104	27,101
South East	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	19	19	19	19	0	19
	Beyond 20 miles	434	590	926	1,160	615	1,775
	Column Total	453	609	945	1,179	615	1,794
South West	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	0	0	0	0	0	0
	Beyond 20 miles	743	817	841	930	11,431	12,361
	Column Total	743	817	841	930	11,431	12,361
Alaska Total	Within 5 miles	10,325	10,502	12,173	12,490	3,174	15,664
	Within 10 miles	11,934	12,149	13,820	14,356	3,183	17,539
	Within 15 miles	14,814	15,029	16,700	17,236	3,571	20,807
	Within 20 miles	16,736	16,970	18,641	19,177	3,997	23,174
	Beyond 20 miles	6,026	6,881	7,328	7,868	26,220	34,088
	Column Total	22,762	23,851	25,969	27,045	30,217	57,262

Table 6.8: Relative Frequency Distribution of Alaskan Households without Existing or Proposed Access to Natural Gas Service by Proximity to Potential Sources of Natural Gas Supply

Region		Distance to EPNGS Settlements					
	Distance to AHR	Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Row Total
Far North	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%
	Within 20 miles	0.0%	0.0%	0.0%	0.0%	0.5%	0.5%
	Beyond 20 miles	0.0%	0.0%	0.0%	0.0%	99.5%	
	Column Total	0.0%	0.0%	0.0%	0.0%		100.0%
Interior	Within 5 miles	48.5%	50.0%	64.6%	67.4%	15.4%	82.8%
	Within 10 miles	48.5%	50.0%	64.6%	69.3%	15.4%	84.7%
	Within 15 miles	48.5%	50.0%	64.6%	69.3%	15.6%	84.9%
	Within 20 miles	48.5%	50.0%	64.6%	69.3%	15.9%	85.2%
	Beyond 20 miles	0.0%	0.0%	0.0%	0.0%	14.8%	
	Column Total	48.5%	50.0%	64.6%	69.3%		100.0%
South Central	Within 5 miles	17.6%	17.6%	17.6%	17.6%	5.2%	22.8%
	Within 10 miles	23.5%	23.7%	23.7%	23.7%	5.2%	28.9%
	Within 15 miles	34.2%	34.3%	34.3%	34.3%	6.5%	40.8%
	Within 20 miles	41.2%	41.4%	41.4%	41.4%	7.9%	49.3%
	Beyond 20 miles	17.9%	20.2%	20.5%	21.3%	29.3%	
	Column Total	59.1%	61.6%	61.9%	62.7%		100.0%
South East	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 20 miles	1.1%	1.1%	1.1%	1.1%	0.0%	1.1%
	Beyond 20 miles	24.2%	32.9%	51.6%	64.7%	34.3%	
	Column Total	25.3%	33.9%	52.7%	65.7%		100.0%
South West	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 20 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Beyond 20 miles	6.0%	6.6%	6.8%	7.5%	92.5%	
	Column Total	6.0%	6.6%	6.8%	7.5%		100.0%
Alaska Total	Within 5 miles	18.0%	18.3%	21.3%	21.8%	5.5%	27.4%
	Within 10 miles	20.8%	21.2%	24.1%	25.1%	5.6%	30.6%
	Within 15 miles	25.9%	26.2%	29.2%	30.1%	6.2%	36.3%
	Within 20 miles	29.2%	29.6%	32.6%	33.5%	7.0%	40.5%
	Beyond 20 miles	10.5%	12.0%	12.8%	13.7%	45.8%	
	Column Total	39.8%	41.7%	45.4%	47.2%		100.0%

Table 6.9: Summary of Distribution of Alaskan Households without Existing or Proposed Access to Natural Gas Service by Proximity to Potential Sources of Natural Gas Supply

	Far North	Interior	South Central	South East	South West	Alaska Total	Interior and South Central
Within 5 miles of EPNGS	0	5,555	16,011	453	743	22,762	21,566
Within 5 miles of AHR	13	9,481	6,170	0	0	15,664	15,651
Within 5 miles of EPNGS and AHR	0	5,555	4,770	0	0	10,325	10,325
Within 10 miles of EPNGS	0	5,732	16,693	609	817	23,851	22,425
Within 10 miles of AHR	13	9,700	7,826	0	0	17,539	17,526
Within 10 miles of EPNGS and AHR	0	5,732	6,417	0	0	12,149	12,419
Within 15 miles of EPNGS	0	7,403	16,780	945	841	25,969	24,183
Within 15 miles of AHR	13	9,726	11,068	0	0	20,807	20,794
Within 15 miles of EPNGS and AHR	0	7,403	9,297	0	0	16,700	16,700
Within 20 miles of EPNGS	0	7,939	16,997	1,179	930	27,045	24,936
Within 20 miles of AHR	25	9,761	13,369	19	0	23,174	23,130
Within 20 miles of EPNGS and AHR	0	7,939	11,219	19	0	19,177	19,518
Beyond 20 miles of both EPNGS and AHR	4,525	1,695	7,954	615	11,431	26,220	9,649

Table 6.10: Potential Natural Gas Usage by Alaskan Households without Existing or Proposed Access to Natural Gas Service by Proximity to Potential Sources of Natural Gas Supply, Mcf

		Distance to EPNGS Settlements					
		Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Row Total
Region	Distance to AHR						
Far North	Within 5 miles	0	0	0	0	2,578	2,578
	Within 10 miles	0	0	0	0	2,578	2,578
	Within 15 miles	0	0	0	0	2,578	2,578
	Within 20 miles	0	0	0	0	4,958	4,958
	Beyond 20 miles	0	0	0	0	897,308	897,308
	Column Total	0	0	0	0	902,265	902,265
Interior	Within 5 miles	1,101,557	1,136,656	1,468,015	1,530,876	349,206	1,880,082
	Within 10 miles	1,101,557	1,136,656	1,468,015	1,574,304	349,206	1,923,510
	Within 15 miles	1,101,557	1,136,656	1,468,015	1,574,304	354,362	1,928,666
	Within 20 miles	1,101,557	1,136,656	1,468,015	1,574,304	361,303	1,935,606
	Beyond 20 miles	0	0	0	0	336,119	336,119
	Column Total	1,101,557	1,136,656	1,468,015	1,574,304	697,421	2,271,725
South Central	Within 5 miles	945,891	945,891	945,891	945,891	277,620	1,223,511
	Within 10 miles	1,264,956	1,272,491	1,272,491	1,272,491	279,405	1,551,896
	Within 15 miles	1,836,060	1,843,595	1,843,595	1,843,595	351,189	2,194,784
	Within 20 miles	2,213,425	2,224,728	2,224,728	2,224,728	426,345	2,651,073
	Beyond 20 miles	961,557	1,085,494	1,102,746	1,145,777	1,577,278	2,723,056
	Column Total	3,174,981	3,310,222	3,327,474	3,370,505	2,003,623	5,374,128
South East	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	3,768	3,768	3,768	3,768	0	3,768
	Beyond 20 miles	86,062	116,997	183,626	230,028	121,955	351,983
	Column Total	89,830	120,765	187,394	233,796	121,955	355,750
South West	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	0	0	0	0	0	0
	Beyond 20 miles	147,337	162,011	166,770	184,419	2,266,767	2,451,186
	Column Total	147,337	162,011	166,770	184,419	2,266,767	2,451,186
Alaska Total	Within 5 miles	2,047,448	2,082,547	2,413,906	2,476,767	629,404	3,106,171
	Within 10 miles	2,366,512	2,409,147	2,740,506	2,846,795	631,189	3,477,984
	Within 15 miles	2,937,616	2,980,251	3,311,610	3,417,899	708,129	4,126,028
	Within 20 miles	3,318,749	3,365,151	3,696,510	3,802,799	792,605	4,595,404
	Beyond 20 miles	1,194,956	1,364,502	1,453,142	1,560,224	5,199,426	6,759,650
	Column Total	4,513,705	4,729,653	5,149,653	5,363,024	5,992,031	11,355,055

Table 6.11: Summary of Potential Natural Gas Usage by Alaskan Households without Existing or Proposed Access to Natural Gas Service by Proximity to Potential Sources of Natural Gas Supply, Mcf

	Far North	Interior	South Central	South East	South West	Alaska Total	Interior and South Central
Within 5 miles of EPNGS	0	1,101,557	3,174,981	89,830	147,337	4,513,705	4,276,538
Within 5 miles of AHR	2,578	1,880,082	1,223,511	0	0	3,106,171	3,103,593
Within 10 miles of EPNGS	0	1,136,656	3,310,222	120,765	162,011	4,729,653	4,446,878
Within 10 miles of AHR	2,578	1,923,510	1,551,896	0	0	3,477,984	3,475,406
Within 15 miles of EPNGS	0	1,468,015	3,327,474	187,394	166,770	5,149,653	4,795,489
Within 15 miles of AHR	2,578	1,928,666	2,194,784	0	0	4,126,028	4,123,450
Within 20 miles of EPNGS	0	1,574,304	3,370,505	233,796	184,419	5,363,024	4,944,809
Within 20 miles of AHR	4,958	1,935,606	2,651,073	3,768	0	4,595,404	4,586,679
Beyond 20 miles of both EPNGS and AHR	897,308	336,119	1,577,278	121,955	2,266,767	5,199,426	1,913,397

6.3: Gas Opportunities in the Interior Region

One of the nearest concentrations of potential gas usage in Alaska is in the Interior section of the state. Table 6.7 shows that of the 15,664 unserved households in the state, some 5,555 (35 percent) are in the Interior region. Over 50 percent of all the unserved households in the state that are within 10 miles of the proposed AHR project are in the Interior region of the state. Some 41 percent of all households in the state living within 20 miles of both types of infrastructure (distribution and proposed transmission) are in the Interior region.[2] We explore the degree of residential geographic concentration, and its implications for potential gas demand in this section.

6.3.1: Overview of the Greater Fairbanks Region: The Fairbanks North Star Borough (FNSB) encompasses nearly 7,500 square miles of interior Alaska near the confluence of the Tanana and Chena Rivers and is located in the proximity of the Alaska Highway route for the proposed gas pipeline. As seen in Table 6.12, Borough population was 82,840 in 2001. Some 53,300 people reside in the ten communities and two military bases in the NSB region. The remaining 29,500 FNSB inhabitants reside in unincorporated places in the greater Fairbanks North Star Borough area. The City of Fairbanks, with a population of 30,224 is Alaska's second largest community and the Borough hub. College, a separate community located three miles northwest of Fairbanks, is the location of the University of Alaska at Fairbanks and includes an additional 11,400 residents.

The greater FNSB area has been inhabited by Koyukon Athabascans for thousands of years. During the gold rush era of the 1890s, Fairbanks began a steamboat landing. The University of Alaska Fairbanks was established in 1915. Eielson Air Force Base, established during Worth War II, is 26 miles south of Fairbanks, near the City of North Pole (1,570 population) and accounts for an additional 5,400 Borough residents. The area continued to grow with construction of the Alcan Highway and with the Trans-Alaska oil pipeline.

The FNSB contains 29,800 occupied housing units plus an additional 3,500 vacant or seasonal dwellings. Approximately one third of these are located in unincorporated places. Average occupied household size in the borough is 2.68, down from 2.70 in 1990.

Average temperatures in the greater FNSB range from –22 degrees Fahrenheit during winter to 72 degrees Fahrenheit during summer. Seasonal extremes can far exceed these this temperate range. According to the Stone and Webster *Railbelt Intertie Reconnaissance Study* (1989, Intertie Study), heating degree days in the Fairbanks area are approximately 40 percent greater than

[2]There are 7,939 unserved households in the Interior region compared to a state-wide total 19,777. See Table 6.1 for details.

Anchorage. The average occupied household would consume approximately 235 Mcf of natural gas per year.[3]

[3]Stone and Webster Engineering Corporation. *Railbelt Intertie Reconnaissance Study,* 1989.

Table 6.12: Fairbanks North Star Borough Population and Housing Characteristics, 2000-2001

		Population			Housing Units				Average Household Size[2]
					Occupied	Vacant		Total	
Item		In Occ HHs	In Group Qs	Total		Total	Seasonal		
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	College	10,651	751	11,402	4,104	397	54	4,501	2.60
2	Ester	1,600	80	1,680	727	87	22	814	2.20
3	Fairbanks[1]	28,325	1,899	30,224	11,075	1,282	121	12,357	2.56
4	Fox	300	-	300	119	40	2	159	2.52
5	Harding Lake	216	-	216	98	391	371	489	2.20
6	Moose Creek	541	1	542	223	57	-	280	2.43
7	North Pole	1,561	9	1,570	605	48	1	653	2.58
8	Pleasant Valley	623	-	623	219	27	13	246	2.84
9	Salcha	854	-	854	317	71	36	388	2.69
10	Two Rivers	482	-	482	177	15	7	192	2.72
11	Subtotal	45,153	2,740	47,893	17,664	2,415	627	20,079	2.56
12	Eileson AFB	5,090	310	5,400	1,448	83	-	1,531	3.52
13	Subtotal	50,243	3,050	53,293	19,112	2,498	627	21,610	2.63
14	Unincorporated	29,517	30	29,547	10,665	1,016	366	11,681	2.77
15	Fairbanks NSB	79,760	3,080	82,840	29,777	3,514	993	33,291	2.68
16	Fairbanks NSB (1990)	74,139	3,581	77,720	26,693	5,130	-na-	31,823	2.70

[1] Includes Fort Wainwright.

[2] Equal to ratio of population in occupied households (a) to occupied housing units (d).

6.3.2: Residential Sector Gas Usage: Residential space heating is accomplished primarily with fuel oil. Electricity, and to a lesser extent, coal and wood, provide only modest baseload space heating requirements.[4] The high incidence of population in unincorporated places, and general lack of population density in the FNSB, is a barrier to widespread gas utility service throughout the area. The authors and expert reviewers of the 1989 Intertie Study determined that a subset equal to 38 percent of the Borough, representing the areas of Fairbanks, North Pole, Farmers Loop, and Beaver Loop comprise the "gas service area" that may be economically served by a gas utility.[5] The number of households in the Fairbanks North Star borough gas service area in 2001 is estimated to be approximately 11,300.

Fairbanks Natural Gas, LLC has operated as a local distribution company for residential and commercial natural gas service in the city of Fairbanks since 1998. Gas from the Enstar system is liquefied in a small facility near Wasilla and transported by cryogenic tanker trailers to its local distribution pipeline system in Fairbanks. As shown in Table 6.13, the residential and commercial natural gas customer base has expanded from 50 in 1999 to 300 in 2001. Average gas usage per customer is about 560 Mcf per year. Retail prices varied from $6.29 to $7.59 per Mcf, depending on customer class and volume of gas usage. The average retail price of gas was $7.19 over the three-year period, 1999-2001.

Table 6.13: Fairbanks Natural Gas, LLC Customers and Gas Usage, 1998-2002

	Customers				Gas Usage			
	Residential	Commercial		Total	Total	Average	Receipts	Price
Year		Large	Small		Mcf/Year	Mcf/Year	$/Year	$/ Mcf
1998				18	3,511	195.1	$ 24,555	$ 6.99
1999				50	29,684	593.7	203,906	6.87
2000				130	73,418	564.8	497,304	6.77
2001	152	10	205	367	157,776	429.9	1,179,208	7.47
2002[a]					275,000		2,400,000	8.73
				Average (1999-2001)		529.4		$ 7.21

The 1989 Intertie Study projected households to grow on average 2 percent annually from the year 2000 to 2010. The statewide annual average household growth used for base case projections by the Institute of Social and Economic Research (2001)[6] is 1.19 percent during the period 2000-2009. The upper range of growth assumes a set of optimistic conditions such as an increase in the real price of ANS Crude, development of ANWR, and the construction of the gas

[4]U.S. Department of Energy, Energy Information Administration. *Residential Energy Consumption Survey.*

[5]Ibid, Vol. 10.

[6]Institute for Social and Economic Research, *Economic Projections: Alaska and the Southern Railbelt 2000-2025,* October ,2001.

pipeline, among other large projects. While the success of the other events is not assured, the construction of the gas pipeline is a necessary condition for the delivery of ANS gas to Fairbanks. Given its location on the pipeline route, Fairbanks is assumed to grow at the forecasted statewide rate of 1.5 percent through 2009. At this rate, occupied households in the gas service area would grow to 12,558 in 2009 (Table 6.14).

The 1989 Intertie Study used historical residential gas usage in Anchorage, adjusted for 40 percent more heating degree-days, to forecast average annual residential gas utility usage in Fairbanks. This forecast was based on the demand for each existing fuel source and an assumed gas market penetration factor. In turn, this penetration rate is driven largely by the difference between the price of natural gas and its substitutes. As shown in Table 6.14, the penetration rate used for the Fairbanks gas service area residential sector varies from 25 percent to 83 percent. The high penetration rate is based on the assumption that the price of gas will be half that of fuel oil, per million BTUs. This rate is lower than Enstar's experience in the Southcentral region, which is ranges from 90 percent, 95 percent, and 98 percent for electricity, fuel oil and propane substitutes, respectively.

Table 6.14: Summary of Potential Natural Gas Usage in the Fairbanks North Star Borough Area by Sector in 2009

Line No.		Formula		Low	Medium	High
1	**Residential Sector**					
2	Projected Total Occupied HHs in 2009[1]		33,048			
3	Proportion of HHs in Gas Service Area[2]		38.0%			
4	Number of HHs in Gas Service Area		12,558			
5	Penetration Rate in 2009[2]			25.0%	50.0%	83.0%
6	Number of HHs Obtaining Gas Service	Line 4 x Line 5		3,140	6,279	10,423
7	Average Annual Household Gas Usage (Mcf/Yr)[2]		235			
8	**Potential Residential Gas Usage in 2009 (Bcf/Yr)**	(Line 6 x Line 7)/1,000,000		**0.7**	**1.5**	**2.4**
9	**Commercial Sector**					
10	FNSB Commercial Space in 1997 (Million Sq Ft)[3]		18.5			
11	Non-Residential Commercial Space to be Heated (Million Sq Ft)[3]		13.3			
12	Projected Non-Res Commercial Space in 2009 (Million Sq Ft)		15.9			
13	Average Commercial Gas Usage (Mcf per Square Foot)[2]		206			
14	Penetration Rate in 2009[2]			25.0%	50.0%	83.0%
15	**Potential Commercial Gas Usage in 2009 (Bcf/Yr)**	(Line 12 x Line 13 x Line 14)/ 1,000		**0.8**	**1.6**	**2.7**
24	**TOTAL FNSB AREA (Bcf per Year)**	Sum (Lines 8 and 15)		**1.6**	**3.1**	**5.2**

Table Notes:

1 Annual average growth is assumed to equal to 1.5% based on the analysis in Institute for Social and Economic Research, *Economic Projections: Alaska and the Southern Railbelt 2000-2025*, October 2001.

2 83% based on Stone and Webster Engineering Corporation. *Railbelt Intertie Reconnaissance Study,* 1989.

3 Special tabulation by Carl McManus, Deputy Appraiser for FNSB (1997).

It is important to remember that a key factor in energy mode switch is recovery of upfront investment cost of heating system conversion to the alternate fuel. The rule-of-thumb for gas utilities' market planning is that if a customer can recoup their cost of conversion within three years then the penetration rate will be over 95 percent, at increments of 30 percent to 35 percent each year over a three to five year period.[7] Although wood heat is not exactly homogenous with thermostat-controlled central heating furnaces, they serve the same ultimate purpose. The 1989 Intertie Study concluded that only 10 percent of all the residences currently burning wood in the greater Fairbanks gas service area would switch to natural gas.

As shown in Table 6.14, potential residential gas usage for space heating and projected in 2009 in the greater Fairbanks area varies from between 0.7 to 2.4 Bcf per year, depending on the rate of gas service penetration. By comparison current gas usage for space heating in the Enstar system in Southcentral is approximately 36 Bcf.[8]

6.3.3: Commercial Sector Gas Usage: The potential for gas consumption by commercial users in the FNSB, such as office buildings and hospitals is summarized in Table 6.14. Commercial energy consumption of gas is assumed to depend on the amount of commercial square footage in use. In 1997, Fairbanks North Star Borough has 18.5 million commercial square feet on their tax roles.[9] Of that total, 13.3 million square feet represent nonresidential space to be heated. The 1989 Intertie Study assumed that commercial building square footage would increase in step with increases in population. This rate will cause commercial, heated square footage to grow to approximately 15.9 million square feet by 2009 and require between 0.8 and 2.7 Bcf per year, depending on the rate of gas service penetration (Table 6.14).

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[7]Communication between ADNR and Dan Dieckgraeff of Enstar, July 1997.

[8]This figure is for residential and commercial usage only. DOE reported total retail sales by Enstar for 1999 is 45.6 Bcf (includes some direct served utility and industrial usage). Gas usage for the region, including the Agrium plant, LNG production, other utility generation, and lease use of natural gas is 213 Bcf.

[9]Special tabulation provided to ADNR by Carl McManus, Deputy Appraiser for FNSB, (1997).

CHAPTER 7: NEW AND EXISTING INDUSTRIAL USAGE OPPORTUNITIES

This chapter investigates the natural gas requirements for new and existing industries in Alaska's economy. The two new industries that we examined included the addition of a major Internet server facility as well as a major petrochemical facility. We also consider the possibilities for expanded natural gas use in the LNG plant operated by Phillips and Marathon and the ammonia-urea plant, recently acquired from Unocal by Agrium, Inc., both located near Kenai, Alaska.

7.1: New Natural Gas Usage Opportunities: Internet Server Facility

Data centers, also referred to as "server farms" or "dot-com hotels" are buildings that house computer equipment to support information and communication systems.[1] It is commonly recognized that these data centers have energy usage requirements that are generally higher than most residential or commercial buildings. The exact usage levels of the facilities, however, are much disputed given how new this sector is to the economy, as well as some common misunderstandings about the energy requirements of the different types and sizes of these facilities.

A recently released report prepared at the University of California, Berkeley and the Lawrence Berkeley Livermore (LBL) Laboratories, has offered a number of new insights into these facilities and their energy usage levels. One of the considerable contributions of this study has been to define a set of common metrics upon which to estimate Internet server energy usage. A brief digression on these matrices is helpful in terms of understanding how we estimated the potential energy needs of a new Internet facility in Alaska. This discussion will focus on the power requirements of the new facilities. Later, these power requirements will be translated into new natural gas usage opportunities.

Power requirements in data centers are commonly referred to as the "power density" of the facility as measured in watts per square foot (W/sq.ft). What is commonly not clarified is exactly what square feet of an internet server facility is the most relevant. Data centers, for instance, can vary considerable in both size and composition.

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[1]This chapter of our report borrows heavily from recently completed research conducted at the University of California, Berkeley and the Lawrence Berkeley Livermore (LBL) Laboratory. This recent research provides an excellent analysis of Internet server farm energy requirements and debunks many recent estimates showing considerable energy demand growth from Internet facilities. This chapter of our report will refrain from repeated citations, however, the reader is encouraged to review the following report for analysis and energy usage estimates that we have used to estimate new Internet natural gas usage opportunities: Jennifer D. Mitchell-Jackson. *Energy Needs in an Internet Economy: A Closer Look at Data Centers.* M.S. Thesis. University of California, Berkeley, 2001.

A data center, like many commercial establishments, can be characterized by its gross floor space. Multiplying this gross floor space by a given power density factor can lead overestimates of power requirements for these facilities. In order to get an accurate representation of these uses, data center building compositions need to be disaggregated into its component parts. Understanding the uses and decomposition of an Internet server facility highlights the need for two important distinctions:

> ***Computer power density:*** the power drawn by the computer equipment divided by the central computer room floor area; and
>
> ***Building power density:*** the total facility power requirements divided by the building gross square feet.

The recent LBL study found that close examination of these characteristics are important since energy usage at these facilities is often overstated due to the usable size of a given facility and the utilization of the equipment within a given relevant space. The LBL study, using actual data from Internet facilities and building information found that actual power density for a typical facility was much less than commonly accepted estimates. For the facility under investigation in the LBL study, researchers found that actual power requirements were 1.4 MWs compared to the "misinformed forecast" of 7.5 MW.[2]

Our analysis uses the LBL ranges of computer floor power densities to estimate ranges of potential power and gas requirements for a typical facility. In addition to three potential power density factors, we used a range of computer floor sizes (in square feet) to estimate the potential total energy requirements. Our analysis assumes that all new Internet power requirements will be generated with natural gas fired generators. Thus, our estimates are an outer boundary of the potential gas usage that could result from a new internet facility.

Lastly, our analysis assumes that power requirements will be generated on-site. We examine three different types of small-scale power generation technologies: a small gas turbine; a reciprocating engine; and a fuel cell. Various heat rate assumptions were used to convert power requirements to natural gas usage requirements. The summary results from our findings are presented in Table 7.1

[2]The misinformed forecast took total design power density and multiplied this by total building square feet. Thus size and utilization were overestimated.

Table 7.1: Summary of Internet Server Power and Gas Usage

Facility Size, Power Density	Generator Capacity (kW)	Gas Turbine		Reciprocating Engine		Fuel Cell	
		Annual Generation (kWh)	Annual Gas Usage (Mcf)	Annual Generation (kWh)	Annual Gas Usage (Mcf)	Annual Generation (kWh)	Annual Gas Usage (Mcf)
Small Facility, Low Power Density	420	3,495,240	34,952	3,495,240	45,438	3,495,240	20,971
Small Facility, Medium Power Density	720	5,991,840	59,918	5,991,840	77,894	5,991,840	35,951
Small Facility, High Power Density	1,020	8,488,440	84,884	8,488,440	110,350	8,488,440	50,931
Medium Facility, Low Power Density	1,050	8,738,100	87,381	8,738,100	113,595	8,738,100	52,429
Medium Facility, Medium Power Density	1,800	14,979,600	149,796	14,979,600	194,735	14,979,600	89,878
Medium Facility, High Power Density	2,550	21,221,100	212,211	21,221,100	275,874	21,221,100	127,327
Large Facility, Low Power Density	1,680	13,980,960	139,810	13,980,960	181,752	13,980,960	83,886
Large Facility, Medium Power Density	2,880	23,967,360	239,674	23,967,360	311,576	23,967,360	143,804
Large Facility, High Power Density	4,080	33,953,760	339,538	33,953,760	441,399	33,953,760	203,723

The Internet facility usages presented in Table 7.1 are comparable to a recently announced Internet server farm that is considering development in Alaska. Netricity, L.L.C. has proposed to develop an Internet server farm that would provide web-hosting services and be connected to clients and users by the fiber optic system that runs the length of the trans-Alaska crude pipeline.[3] According to the proposal, the $1 billion facility would house 500,000 Internet servers in a one billion square foot building, with gas usage of approximately 120 MMcf/d. The facility would generate approximately 400 MW of electricity. Assuming that all of this electricity is used on site, this level of power usage (400 watts per square foot) is considerably higher than the high power density example illustrated above (85 watts per square foot).[4]

7.2: New Natural Gas Usage Opportunities: Petrochemical Facility

The potential gas usage opportunities associated with new petrochemical industries in Alaska is the subject of this section. In part, this analysis was stimulated by the opportunities that are currently being explored by Williams Energy Company. In a presentation before the Alaska Highway Natural Gas Policy Council, Williams announced that it was initiating a study of the petrochemical opportunities within the state. One potential option that has been discussed is the development of a project producing ethylene and propylene.

The Williams proposal is based upon a facility that would use over one Bcf/d of natural gas. The plant would take ethane from the natural gas stream to crack ethylene. The ethylene, in turn, is used to develop polyethylene pellets, which would be shipped by rail to Anchorage or Seward for tanker shipment to global markets. Most of the residual gas (methane) would be re-injected back into the natural gas pipeline serving the facility. The plant would employ close to 350 full time personnel and a potential payroll of $18 million per year, with as much as $15 million a year paid to the Alaska Railroad for transportation services.[5] This petrochemical facility opportunity, according to company spokespeople, is still under investigation.

Almost all ethylene produced is consumed as feedstock for manufacturing other petrochemicals. Although some ethylene is shipped across the oceans in large quantities, the preference is usually to ship first-generation products such as polyethylene, or ethyl benzene.[6] The economics for the production of ethylene depends to a large extent on the prices for feedstocks and co-products and transportation charges. In the U.S., the feedstocks of choice have been the

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[3] *Petroleum News Alaska*, Volume 7, Number 101-1, August 1, 2001

[4] The Netricity proposal is not clear on exactly what square feet are being presented in its overall proposed project size. As noted earlier, power density is higher when concentrated on core computer room density.

[5] Kay Cashman. "Williams Wants To Operate Gasline. *Petroleum News Alaska*. (December 2, 2001): 11.

[6] *Kirk-Othmer Encyclopedia of Chemical Technology*. Fourth Edition, Volume 9. New York: John Wiley and Sons: 908.

lighter feeds of ethane and propane. Approximately 70 percent of U.S. ethylene production is from ethane, propane, and butane. Ethane feed generally gives the lowest cost of production and the lowest capital investment relative to other feedstocks.[7] Cheaper alternative feedstocks, in some instances, can offset this advantage.

In the U.S., the Gulf Coast produces and consumes the majority of the ethylene production. In fact, six of the 10 largest plants in the U.S. are in Texas and Louisiana. These plants are served by an extensive system of pipelines connecting the production and consuming plants. Currently operational U.S. ethylene plants, their locations, and typical feedstocks are provided in Table 7.2. These facilities are provided in the annual International Survey of Ethylene From Steam Crackers, *Oil and Gas Journal*, April 2001.

[7] *Ibid.*, 910.

Table 7.2: Major Ethylene Facilities in the U.S.

Facility	Location	Total Capacity (TPY)	Typical Feedstock or Feedstock Mixture on Which Listed Capacity is Based				
			Ethane	Propane	Butane	Naphtha	Other
BP	Chocolate Bayou, TX	1,451,000	50%	35%		15%	
Chevron Phillips Chemical Co	Cedar Bayou, TX	794,000	30%	20%	25%	25%	
Chevron Phillips Chemical Co	Port Arthur, TX	794,000	70%	30%			
Chevron Phillips Chemical Co	Sweeny, TX	181,000	80%	20%			
Chevron Phillips Chemical Co	Sweeny, TX	318,000	100%				
Chevron Phillips Chemical Co	Sweeny, TX	680,000	80%	20%			
Chevron Phillips Chemical Co	Sweeny, TX	907,000	38%	37%	25%		
Condea Vista Co	Westlake, LA	447,000	100%				
Dow Chemical Co	Freeport, TX	590,000	50%	50%			
Dow Chemical Co	Freeport, TX	950,000	10%	70%		20%	
Dow Chemical Co	Plaquemine, LA	500,000	80%	20%			
Dow Chemical Co	Plaquemine, LA	680,000	20%	30%		50%	
Dow Chemical Co	Seadrift, TX	440,000	100%				
Dow Chemical Co	Taft, LA	590,000	25%	25%		50%	
Dow Chemical Co	Taft, LA	410,000	25%	25%		50%	
Dow Chemical Co	Texas City, TX	680,000	95%	5%			
DuPont	Orange, TX	590,000	100%				
Eastman Chemical Co	Longview, TX	684,000	25%	67%	7%	1%	
Equistar Chemical Co	Channelview, TX	875,000	5%			95%	
Equistar Chemicals, LP	Chocolate Bayou, TX	875,000	5%			95%	
Equistar Chemicals, LP	Clinton, IO	544,000				100%	
Equistar Chemicals, LP	Corpus Christi, TX	476,000	80%	20%			
Equistar Chemicals, LP	Lake Charles, LA	771,000	10%	30%		60%	
Equistar Chemicals, LP	LaPorte, TX	385,000	80%	20%			
Equistar Chemicals, LP	Morris, IL	789,000	60%	20%		20%	
ExxonMobil Chemical Co	Baton Rouge, LA	550,000	80%	20%			
ExxonMobil Chemical Co	Baytown, TX	882,000					
ExxonMobil Chemical Co	Beaumont, TX	1,890,000	50%	15%	35%		
ExxonMobil Chemical Co	Houston, TX	816,000	90%	10%			
Formosa Plastics Corp	Point Comfort, TX	356,000	33%	33%		34%	
Hunstman Corp	Odessa, TX	714,000					
Hunstman Corp	Port Arthur, TX	230,000				60%	40%
Hunstman Corp	Port Neches, TX	551,000					
Javelina Co	Corpus Christi, TX	136,000					
Shell Chemicals Ltd	Deer Park, TX	151,000	15%		5%	50%	30%
Shell Chemicals Ltd	Norco, LA	952,000	45%	5%	5%	45%	
Shell Chemicals Ltd	Norco, LA	626,000	5%			35%	60%
Sunoco Inc	Marcus Hook, PA	225,000	50%	50%			
Westlake Petrochemicals Corp	Calvert City, KY	181,000		100%			
Westlake Petrochemicals Corp	Sulphur, LA	590,000	65%	35%			
Westlake Petrochemicals Corp	Sulphur, LA	436,000	100%				
Williams Energy Services	Geismar, LA	567,000	90%	10%			

Estimating the amount of natural gas used by a typical petrochemical facility like an ethylene plant is a very complicated process. These plants, which are constructed at what is referred to as "world class scale," can amount to billions of dollars of investment. Thus, prior to development, a substantial amount of work is conducted in optimizing plant design, including the use of feedstocks. Critical to this analysis is the liquids composition of the ANS gas stream, which is under the producers' control and would be influenced by requirements for gas cycling for EOR as well as by relative prices for various components in the gas stream.

While large ethylene plants can use a significant amount of natural gas, it is important to keep in mind that only the ethane, propanes, and butanes of the gas are actually used for production. One of the byproducts of the cracking process is methane – often referred to as residual gas. In some instances, this unused methane can actually be injected back into the natural gas pipeline.[8]

Given the myriad number of variables associated with estimating natural gas use at a "typical" ethylene plant, we have opted to use a "comparable facilities" approach to estimating potential natural gas usage at facilities located in Louisiana. These facilities and their typical annual natural gas consumption are presented in Table 7.3. These facilitates are all of "world class scale." In addition, one of these facilities is an ethylene and propylene facility owned and operated by Williams Energy.

[8]It is common industry practice to refer to ethylene "crackers" when referring to the production process of converting ethane to ethylene. However, this is a misnomer. Ethylene is not cracked by rather is a product of the cracking process. For a straightforward description of the ethylene production process, see Donald L. Burdick and William L. Leffler. *Petrochemicals in Non-Technical Language*. Houston, Pennwell Books: 1990.

Table 7.3: Typical Gas Usage at Major Ethylene Facilities in Louisiana

Facility	Location	Total Nameplate Capacity (TPY)	Typical Feedstock or Feedstock Mixture on Which Listed Capacity is Based					Gas Usage MMcf	Gas Usage MMcf/d	Gas Usage (Mcf/TPY)
			Ethane	Propane	Butane	Naptha	Other			
Condea Vista Co	Westlake, LA	447,000	100%					3,528	9.67	7.89
Dow Chemical Co	Plaquemine, LA	500,000	80%	20%						
Dow Chemical Co**	Plaquemine, LA	680,000	20%	30%		50%		50,000	136.99	42.37
Dow Chemical Co	Taft, LA	590,000	25%	25%		50%				
Dow Chemical Co**	Taft, LA	410,000	25%	25%		50%		7,908	21.67	19.29
ExxonMobil Chemical Co	Baton Rouge, LA	550,000	80%	20%				20,020	54.85	36.40
Shell Chemicals Ltd	Norco, LA	626,000	5%			35%	60%	13,540	37.10	21.63
Williams Energy Services	Geismar, LA	567,000	90%	10%				6,200	16.99	10.93

** *Combined Plant Totals*

7.3: Expanding Natural Gas Usage at Existing Industrial Facilities

Currently, there are two significant industrial users of natural gas in Alaska: the LNG facility owned by Phillips and Marathon in Kenai, and the Agrium, Inc. ammonia-urea facility, located in neighboring Nikiski. A graph of the historic natural gas consumption for each industrial facility is presented in Figure 7.1.

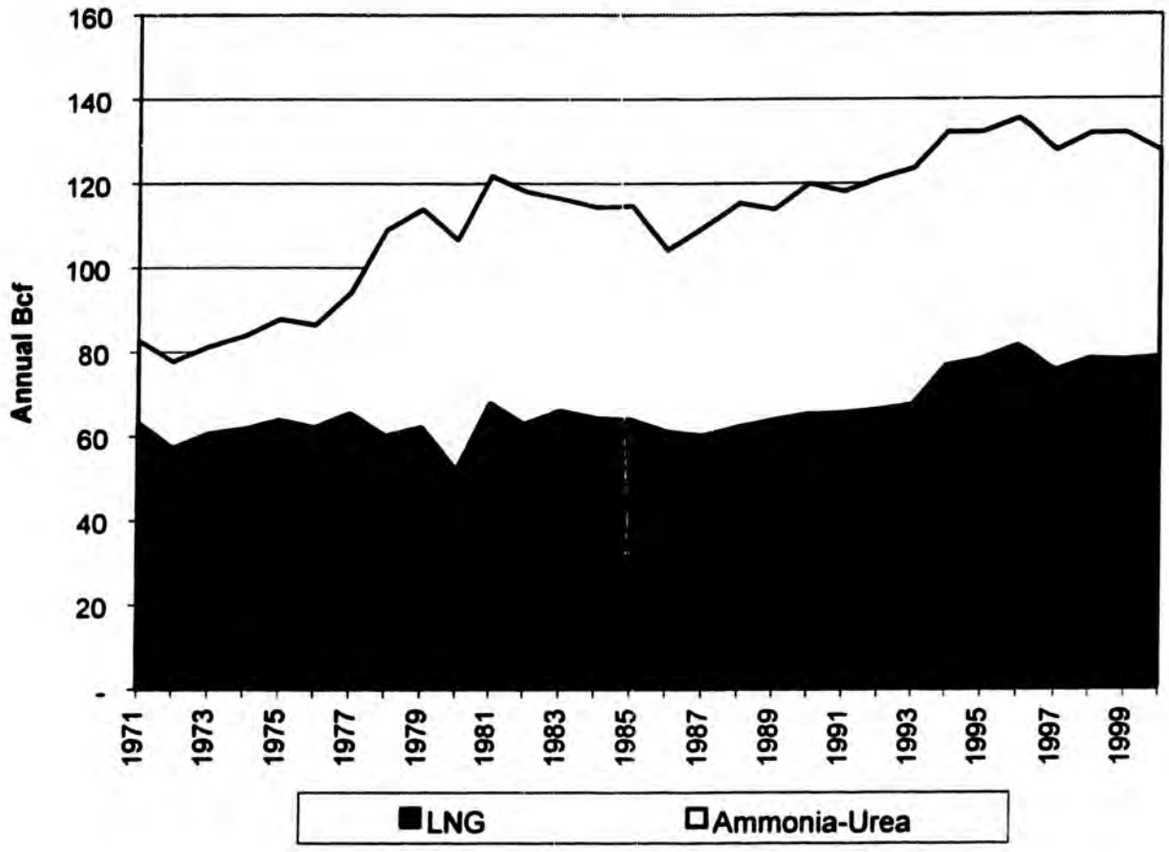

Figure 7.1: Annual LNG and Ammonia-Urea Use of Natural Gas

Source: Alaska Department of Natural Resources.

Phillips and Marathon share ownership in the LNG liquefaction facility and tankers located in Kenai, Alaska. The LNG facility began operating in 1969. The plant consumes 220 million cubic feet of natural gas per day (78 Bcf per year). The facility produces about 1.5 million metric tons of high-methane LNG per year. The LNG is sold to Tokyo Electric and Tokyo Gas companies. Today, the Phillips-Marathon LNG plant supplies approximately one percent of Japan's LNG consumption. The Kenai plant is a baseload LNG facility. Most other U.S. commercial LNG plants are peak saving operations, meaning small LNG plants typically located near utilities. Peak-shaving LNG plants liquefy and store gas

delivered by pipeline at low demand periods for later use during peak periods. Baseload plants like the Phillips-Marathon plant in Kenai serve markets that are located far away from sufficient supplies to enable economic deliveries by pipeline. As seen in Figure 7.1, the use of natural gas at the LNG facility has been relatively constant since 1996. Given the steady, long term nature of these contracts, this relatively steady use of natural gas is not unexpected.

The economics of LNG are complicated and dependent upon a number of factors, not the least of which is forecasting the demand for LNG in Asian and world markets, as well as the direction of cost trends in other competing areas around the world. There have been a number of studies of expanded LNG production opportunities in Alaska over the past several years. Developing an alternative to these comprehensive studies was beyond the scope of this study.

However, we have examined the trends in past LNG natural gas usage over the past several years to see if few additional production opportunities exist. As we noted above, the trends in gas usage are relatively stable, and outside year-to-year variations, we see little opportunities to expand production beyond its current levels. Currently, the Kenai LNG facility is operating slightly below its all-time high level of usage of natural gas of 81 Bcf that occurred in 1996. In 2000, LNG uses of natural gas were at 78.5 Bcf, so conceivably, there may be an additional 2.8 Bcf of additional usage at the facility.

We have also examined the potential use of natural gas by the state's other large industrial natural gas user: The Agrium ammonia-urea plant in Southcentral Alaska. This plant produces anhydrous ammonia (NH_3) and urea fertilizer based on technology dating back to the 1960s. Plant output capacity is approximately two million tons per year, divided roughly between ammonia and urea. Natural gas (methane) is combined with nitrogen at high temperatures to produce NH_3 plus carbon dioxide and sulfur by-products. NH_3 is the feedstock for many other products, including nitrogen-based urea fertilizer. Ammonia is sold in separate markets and is an intermediate product used to make urea. Sometimes the relative price of urea is low. In such cases, it many be profitable to intensify ammonia production and reduce or completely halt urea production. Nearly all plant output is exported to markets in Southeast Asia, primarily Thailand.

Based upon information included in the Manufacturing and Industrial Plant Database (MIPD), published by The HIS Energy Group, at about 49 Bcf per year, the Agrium plant currently operates at about 80 percent of capacity. The high point for natural gas usage for the facility, as seen in Figure 7.1, was in 1996 when the facility used about 56 Bcf for that year. The facility consumed less natural gas from year to year since 1993. Hence, there appear to be short run opportunities for increased gas usage of up to 7.2 Bcf per year.

In a recent article published by *Petroleum News Alaska*, Agrium noted that they were interested in expanding its Cook Inlet operations, which could translate into

additional annual usage of 30 Bcf per year.[9] Chris Tworek, Vice President of Supply for Agrium noted that, in order for the facility to expand production, its natural gas input prices would have to be competitive with global prices, which range between 75 cents to $1.00 per MMBtu. The potential for Agrium to increase natural gas usage by 30 Bcf per year is unlikely to occur a prices prevailing in the Cook Inlet Basin today but should be considered in a long run forecast of new industrial uses of natural gas in Alaska.

[9]Kristen Nelson. "Agrium Would Like to Grow Cook Inlet Operation." *Petroleum News Alaska*. (November 25, 2001): A14.

CHAPTER 8: NEW POWER GENERATION OPPORTUNITIES

The Alaska power system can be segregated into three categories: (1) interconnected utilities in the Railbelt; (2) small, isolated, non-interconnected utilities in the Bush; and (3) mid-size, non-interconnected utilities like Kodiak Electric Association and Copper Valley Electric Association, Inc.

The Alaska Systems Coordinating Council (ASCC) provides oversight and coordination of statewide electric utility operations for reliability purposes. The ASCC is comprised of 17 electric utilities, three state agencies, and a federal agency. Nine ASCC members are interconnected in the railbelt region to serve the Anchorage Bowl, Fairbanks area, and the Kenai Peninsula. These members account for approximately 75 percent of the utility generating capacity in Alaska.

The ASCC notes that, "the Alaska electric system is truly isolated and does not have a transmission grid as normally defined." The transmission systems that do exist are commonly referred to as "isolated radial single lines." There is no connection with transmission grids outside of Alaska. Many of the transmission system issues associated with the lower 48 simply do not exist in Alaska.[1]

Power transmission interties on the northern and southern ends of the railbelt system between Fairbanks and Kenai Peninsula improve reliability by providing a second set of transmission links between Healy and Fairbanks in the north and between Anchorage and the Kenai Peninsula to the south. The Northern Intertie route selection process is complete and construction plans are finalized. This line will be constructed for 230 kilovolts (kV), but operated at 138 in the near term. The line is expected to be fully operational within three years. The Southern Intertie route selection process, including its associated environmental impact statement and findings, is underway.

The majority of Alaska's 250 rural towns and villages are not interconnected. The rural town and village power systems typically rely on a single local diesel or fuel oil generating plant. For these areas of the state, power cost and generator reliability (as opposed to transmission reliability) are of the greatest importance. According to the ASCC, maintenance programs, system upgrades, and applying new small-scale power generation technologies are a high priority.

One of the more recent investigations of the potential for new power generation in Alaska, as well as increasing the efficiency of existing power generation stations, was conducted by CH2M Hill in a report prepared for the Regulatory

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[1]These include issues associated with interconnection rules and costs, transmission governance and pricing, long term transmission planning for wholesale competition, and the development of Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs).

Commission of Alaska (RCA) and the Alaska Legislature.[2] This report, hereafter referred to as the CH2M Hill report, is a comprehensive examination of electric restructuring issues, how they relate to Alaska's power industry, and the potential costs and benefits of moving forward with greater competition. The study notes that "...there is no restructuring model in existence today that would work in rural Alaska among the villages and cities that are not interconnected to the Railbelt system."

The report offers three alternative pathways for the future development of Alaska's power system:

(1) The State can "fix the potholes" in its current system;

(2) The State can choose a scenario that focuses on rapidly "commoditizing kilowatts" in an effort to capture wholesale power market benefits; or

(3) The State can choose a course of "controlled evolution," transitioning the current regulated system into a more competitive and diverse marketplace.

The empirical analysis conducted in the CH2M Hill report included a "least cost dispatch" model for the state's railbelt utilities. Least cost multi-area dispatch models are common tools that are used in the lower 48 to examine the efficiency opportunities for coordinated least cost dispatch of power generation facilities. The approach, in its most simple form, stacks each generator by the least cost generation facility to its most expensive. The intersection of demand to this least-cost developed supply curve represents the amount of power generation that would be dispatched to the market, as well as the market clearing price for power.

While the CH2M Hill report findings were modestly in favor of moving forward with a limited form of competition in Alaska, the RCA Staff was somewhat more critical of the idea. In comments attached to Order 7 in Docket Number R-97-10, the Commission Staff recommended that "... the gains from restructuring appear to be modest, while risks are potentially considerable. Accordingly, Staff recommends that no policy action be taken at this time to restructure Alaska's Railbelt utility system."[3]

With regards to the costs of moving forward with restructuring, the Staff comments noted that:

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[2]Karl Robago, Tom Feiler, Floyd Damron, and Deanana Gamle. *Study of Electric Utility Restructuring in Alaska.* Report to the Alaska Public Utilities Commission and the Alaska State Legislature. June 30, 1999.

[3]Comments of the RCA Staff, Attachment to Order No. 7, Docket R-97-10, *In the Matter of Regulations Defining the Future Market Structure of Alaska's Electric Industry.* June 22, 2001.

> The Railbelt at present does not appear to have the infrastructure – either in diversity of generator ownership, or in transmission redundancy – to support robust competition. The presence of long-term fuel supply contracts may predetermine competitive outcomes if retail competition is introduced in the near term. It appears that Alaska has little gain, and potentially much to lose, by any quick movement to retail competition. The next five to ten years will see resolution of a number of important issues that will profoundly affect the economics of electricity production in the Railbelt.[4]

The issue of electric restructuring is important to the future in-state opportunities for increased gas consumption. In the lower 48, the advent of wholesale and retail competition has resulted in an explosion of new merchant power plant construction. These merchant facilities are typical simple cycle (CT) or combined-cycle[5] (CC) gas generating units. According to a U.S. Department of Energy study, about 50 percent of the future growth in natural gas demand will come from serving the fuel requirements of the power generation facilities.[6]

However, there are a number of factors that dampen the possibilities that Alaska could experience an explosion in new gas fired generation resulting from competition. The RCA Staff raise a number of important issues with regards to both competition and the need for new power generation. Some of the factors that limit the possibilities of competition and new competitive power generation include:

- Large reserve capacity margins that considerably delay when new units to the Railbelt need to be added;
- Utilities that are primarily customer-owned; and
- The prevalence of long term wholesale electricity and fuel contracts.[7]

Referencing an earlier Black and Veatch study on power generation in Alaska, the RCA Staff notes that the State does not have a forecast power generation capacity addition need until the year 2014.[8]

Given the RCA Staff comments and our own analysis of past power demand trends in Alaska, we have limited our analysis of new potential gas generation to

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[4]Commission Staff Comments at 2.

[5]A combined cycle generator is one that includes initial-stage turbine generation with a heat recovery unit for additional generation to enhance overall power generation efficiency.

[6]US Department of Energy, Annual Energy Outlook to 2020. Washington: Energy Information Administration, Table A.13.

[7]Commission Staff Comments at 10.

[8]Commission Staff Comments at 11, referencing the Black and Veatch Power Pooling Study at 5-1 conducted on the behalf of the RCA, 1998.

two sources: first, fuel switching by the Bush utilities and larger non-interconnected systems in Alaska; and second, a new power generation facility located in close proximity to the proposed Alaska Highway Route (AHR). We will assume that the AHR example could be translated into a "gas by wire" application, where power generated from this facility could be moved to neighboring areas to displace existing on-site power generation.

8.1: Fuel Switching Opportunities for Bush and Larger Non-Interconnected Systems

Our analysis of fuel switching opportunities for power generation facilities is similar to that in our residential geographic proximity analysis. There is, however, a difference in how the power plant information is referenced to geographic locations. Due to the unavailability of specific geo-referencing information on many of the smaller power generating units, we aggregated generators (oil and diesel) by ZIP codes and used the U.S. Census-developed SIP code digital boundaries in the overlay procedures. Figure 8.1 maps all power generation facilities in Alaska based upon this method, while Figure 8.2 highlights those facilities that are currently being fired by fuel oil or diesel fuel. The quantitative results of the proximity analysis have been presented in Tables 8.1, 8.2, and 8.3 (capacity by region). The natural gas usage associated with switching these units are provided in Table 8.4 and 8.5.

The geographic distribution of oil and diesel fired generators are different from those conducted earlier for residential customers. In particular, 34.2 percent of the potential fuel switching generating capacity is located within five miles of the proposed AHR (see Table 8.2). Some 202 MWs of capacity are located in the Interior section, 12.9 MWs of capacity is located within the Southcentral region, and 2.5 MWs are located in the Southeastern region (see Table 8.1).

The largest opportunities for fuel switching through power generation are in the interior region – primarily in Fairbanks. Some 96 percent of the capacity available for fuel switching is located in this region, and within 5 miles of the AHR.

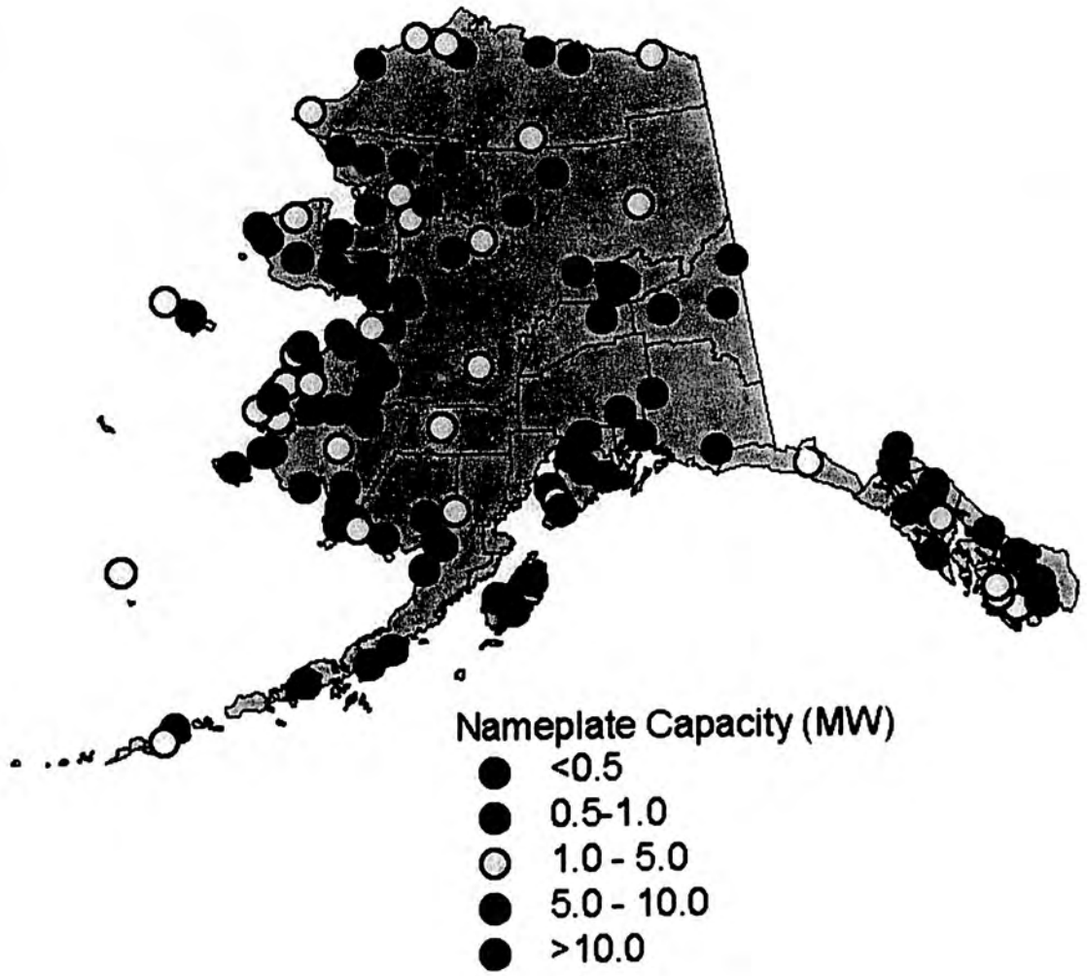

Figure 8.1: Total Power Generation Capacity by Location

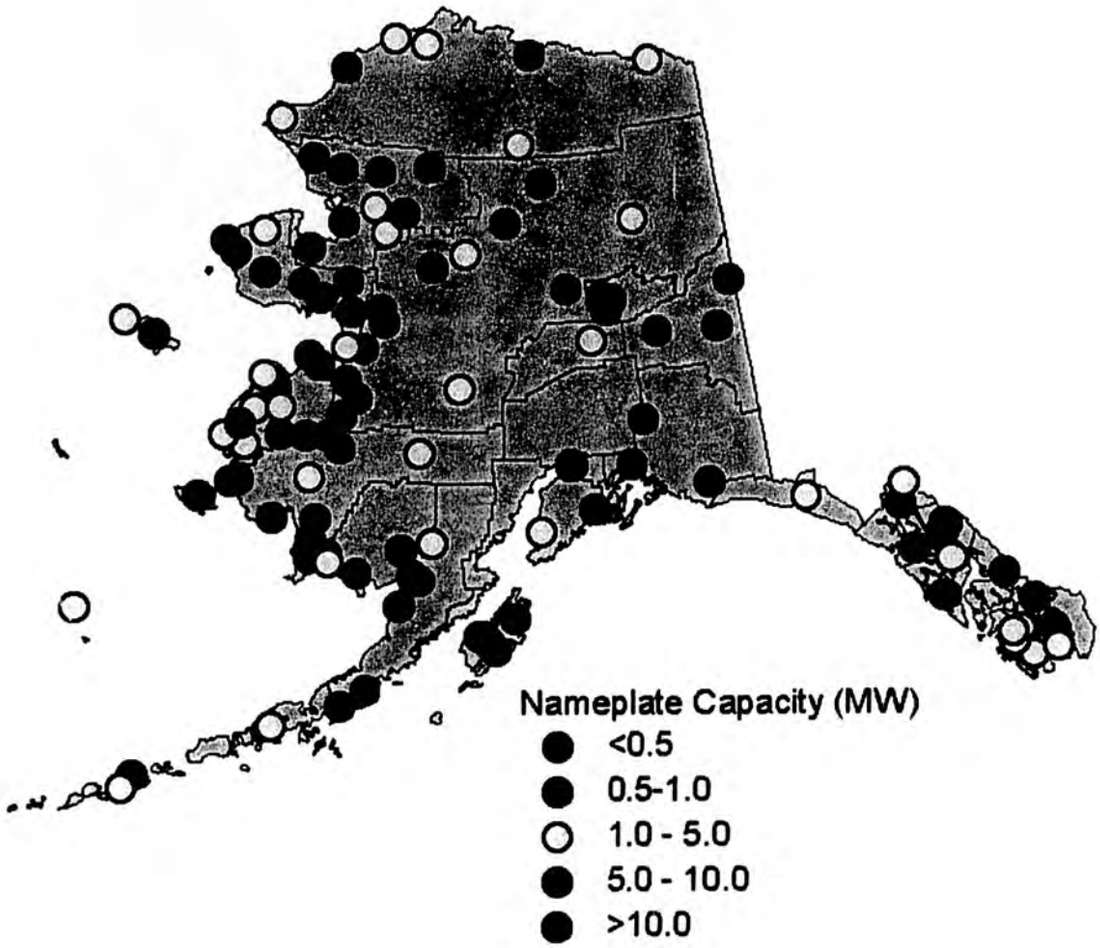

Figure 8.2: Oil and Diesel Fired Generation Capacity by Location

Table 8.1: Distribution of Oil and Diesel Fired Power Generation Capacity by Proximity to Potential Sources of Natural Gas Supply (kW Capacity)

Region		Distance to EPNGS Settlements					
		Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Total
	Distance to AHR						
Far North	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	0	0	0	0	760	760
	Beyond 20 miles	0	0	0	0	48,228	48,228
	Total	0	0	0	0	48,988	48,988
Interior	Within 5 miles	0	0	192,900	192,900	9,275	**202,175**
	Within 10 miles	0	0	192,900	192,900	9,275	202,175
	Within 15 miles	0	0	192,900	192,900	9,275	202,175
	Within 20 miles	0	0	192,900	192,900	9,275	202,175
	Beyond 20 miles	0	0	0	0	9,294	9,294
	Total	0	0	192,900	192,900	18,569	211,469
South Central	Within 5 miles	0	0	0	2,536	10,456	**12,992**
	Within 10 miles	0	0	10,102	15,138	10,456	25,594
	Within 15 miles	0	0	10,102	15,138	10,456	25,594
	Within 20 miles	0	0	10,102	15,138	48,366	63,504
	Beyond 20 miles	0	10,403	10,403	10,403	12,600	23,003
	Total	0	10,403	20,505	25,541	60,966	86,507
South East	Within 5 miles	2,500	2,500	2,500	2,500	0	**2,500**
	Within 10 miles	2,500	2,500	2,500	2,500	0	2,500
	Within 15 miles	2,500	2,500	2,500	2,500	0	2,500
	Within 20 miles	2,500	2,500	11,130	11,130	0	11,130
	Beyond 20 miles	97,600	136,058	162,178	166,008	3,586	169,594
	Total	100,100	138,558	173,308	177,138	3,586	180,724
South West	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	0	0	0	0	0	0
	Beyond 20 miles	0	0	28,775	29,205	78,755	107,960
	Total	0	0	28,775	29,205	78,755	107,960
Alaska Total	Within 5 miles	2,500	2,500	195,400	197,936	19,731	217,667
	Within 10 miles	2,500	2,500	205,502	210,538	19,731	230,269
	Within 15 miles	2,500	2,500	205,502	210,538	19,731	230,269
	Within 20 miles	2,500	2,500	214,132	219,168	58,401	277,569
	Beyond 20 miles	97,600	146,461	201,356	205,616	152,463	358,079
	Total	100,100	148,961	415,488	424,784	210,864	635,648

Table 8.2: Relative Frequency Distribution of Oil and Diesel Fired Power Generation Capacity by Proximity to Potential Sources of Natural Gas Supply (Percent of Total)

		Distance to EPNGS Settlements					
		Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Row Total
	Distance to AHR						
Far North	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 20 miles	0.0%	0.0%	0.0%	0.0%	1.6%	1.6%
	Beyond 20 miles	0.0%	0.0%	0.0%	0.0%	98.4%	
	Column Total	0.0%	0.0%	0.0%	0.0%		100.0%
Interior	Within 5 miles	0.0%	0.0%	91.2%	91.2%	4.4%	**95.6%**
	Within 10 miles	0.0%	0.0%	91.2%	91.2%	4.4%	95.6%
	Within 15 miles	0.0%	0.0%	91.2%	91.2%	4.4%	95.6%
	Within 20 miles	0.0%	0.0%	91.2%	91.2%	4.4%	95.6%
	Beyond 20 miles	0.0%	0.0%	0.0%	0.0%	4.4%	
	Column Total	0.0%	0.0%	91.2%	91.2%		100.0%
South Central	Within 5 miles	0.0%	0.0%	0.0%	2.9%	12.1%	15.0%
	Within 10 miles	0.0%	0.0%	11.7%	17.5%	12.1%	29.6%
	Within 15 miles	0.0%	0.0%	11.7%	17.5%	12.1%	29.6%
	Within 20 miles	0.0%	0.0%	11.7%	17.5%	55.9%	73.4%
	Beyond 20 miles	0.0%	12.0%	12.0%	12.0%	14.6%	
	Column Total	0.0%	12.0%	23.7%	29.5%		100.0%
South East	Within 5 miles	1.4%	1.4%	1.4%	1.4%	0.0%	1.4%
	Within 10 miles	1.4%	1.4%	1.4%	1.4%	0.0%	1.4%
	Within 15 miles	1.4%	1.4%	1.4%	1.4%	0.0%	1.4%
	Within 20 miles	1.4%	1.4%	6.2%	6.2%	0.0%	6.2%
	Beyond 20 miles	54.0%	75.3%	89.7%	91.9%	2.0%	
	Column Total	55.4%	76.7%	95.9%	98.0%		100.0%
South West	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 20 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Beyond 20 miles	0.0%	0.0%	26.7%	27.1%	72.9%	
	Column Total	0.0%	0.0%	26.7%	27.1%		100.0%
Alaska Total	Within 5 miles	0.4%	0.4%	30.7%	31.1%	3.1%	**34.2%**
	Within 10 miles	0.4%	0.4%	32.3%	33.1%	3.1%	36.2%
	Within 15 miles	0.4%	0.4%	32.3%	33.1%	3.1%	36.2%
	Within 20 miles	0.4%	0.4%	33.7%	34.5%	9.2%	43.7%
	Beyond 20 miles	15.4%	23.0%	31.7%	32.3%	24.0%	
	Column Total	15.7%	23.4%	65.4%	66.8%		100.0%

Table 8.3: Summary of Distribution of Oil and Diesel Fired Power Generation Capacity by Proximity to Potential Sources of Natural Gas Supply (kW Capacity)

	Far North	Interior	Southcentral	Southeast	Southwest	Alaska
Within 5 miles of EPNGS	0	0	0	100,100	0	100,100
Within 5 miles of AHR	0	202,175	12,992	2,500	0	217,667
Within 10 miles of EPNGS	0	0	10,403	138,558	0	148,961
Within 10 miles of AHR	0	**202,175**	25,594	2,500	0	230,269
Within 15 miles of EPNGS	0	192,900	20,505	173,308	28,775	415,488
Within 15 miles of AHR	0	202,175	25,594	2,500	0	230,269
Within 20 miles of EPNGS	0	192,900	25,541	177,138	29,205	424,784
Within 20 miles of AHR	760	202,175	63,504	11,130	0	277,569
Beyond 20 miles of both	48,228	9,294	12,600	3,586	78,755	152,463

Tables 8.4, 8.5, and 8.6 present the gas usage associated with each of the power generation facilities identified in earlier capacity tables. As presented in the bottom right hand corner of Table 8.4, the total increase in gas usage, associated with switching power generation fuels, is 32.8 Bcf per year. The majority of the new gas usage opportunity rests within the Interior section of Alaska, primarily Fairbanks (30.28 Bcf).

Table 8.4: Distribution of Potential Gas Usage of Oil and Diesel Fired Generation Units by Proximity to Sources of Natural Gas Supply (MMcf)

Region		Distance to EPNGS Settlements					
		Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Total
	Distance to AHR						
Far North	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	0	0	0	0	95	95
	Beyond 20 miles	0	0	0	0	4,348	4,348
	Total	0	0	0	0	4,443	4,443
Interior	Within 5 miles	0	0	28,896	28,896	1,388	**30,284**
	Within 10 miles	0	0	28,896	28,896	1,388	30,284
	Within 15 miles	0	0	28,896	28,896	1,388	30,284
	Within 20 miles	0	0	28,896	28,896	1,388	30,284
	Beyond 20 miles	0	0	0	0	1,185	1,185
	Total	0	0	28,896	28,896	2,574	31,469
South Central	Within 5 miles	0	0	0	565	1,666	2,231
	Within 10 miles	0	0	1,670	2,732	1,666	4,398
	Within 15 miles	0	0	1,670	2,732	1,666	4,398
	Within 20 miles	0	0	1,670	2,732	6,398	9,130
	Beyond 20 miles	0	1,488	1,488	1,488	2,103	3,592
	Total	0	1,488	3,158	4,220	8,502	12,722
South East	Within 5 miles	285	285	285	285	0	285
	Within 10 miles	285	285	285	285	0	285
	Within 15 miles	285	285	285	285	0	285
	Within 20 miles	285	285	1,315	1,315	0	1,315
	Beyond 20 miles	14,207	19,582	23,444	23,947	407	24,354
	Total	14,492	19,867	24,759	25,262	407	25,669
South West	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	0	0	0	0	0	0
	Beyond 20 miles	0	0	5,161	5,215	10,140	15,355
	Total	0	0	5,161	5,215	10,140	15,355
Alaska Total	Within 5 miles	285	285	29,181	29,746	3,054	**32,800**
	Within 10 miles	285	285	30,850	31,912	3,054	34,967
	Within 15 miles	285	285	30,850	31,912	3,054	34,967
	Within 20 miles	285	285	31,880	32,942	7,881	40,823
	Beyond 20 miles	14,207	21,071	30,094	30,650	18,184	48,834
	Total	14,492	21,355	61,974	63,592	26,065	89,657

Table 8.5: Relative Frequency Distribution of Potential Gas Usage of Oil and Diesel Fired Generation Units by Proximity to Sources of Natural Gas Supply (Percent of Total)

Region		Distance to EPNGS Settlements					
		Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Row Total
	Distance to AHR						
Far North	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 20 miles	0.0%	0.0%	0.0%	0.0%	2.1%	2.1%
	Beyond 20 miles	0.0%	0.0%	0.0%	0.0%	97.9%	
	Column Total	0.0%	0.0%	0.0%	0.0%		100.0%
Interior	Within 5 miles	0.0%	0.0%	91.8%	91.8%	4.4%	96.2%
	Within 10 miles	0.0%	0.0%	91.8%	91.8%	4.4%	96.2%
	Within 15 miles	0.0%	0.0%	91.8%	91.8%	4.4%	96.2%
	Within 20 miles	0.0%	0.0%	91.8%	91.8%	4.4%	96.2%
	Beyond 20 miles	0.0%	0.0%	0.0%	0.0%	3.8%	
	Column Total	0.0%	0.0%	91.8%	91.8%		100.0%
South Central	Within 5 miles	0.0%	0.0%	0.0%	4.4%	13.1%	17.5%
	Within 10 miles	0.0%	0.0%	13.1%	21.5%	13.1%	34.6%
	Within 15 miles	0.0%	0.0%	13.1%	21.5%	13.1%	34.6%
	Within 20 miles	0.0%	0.0%	13.1%	21.5%	50.3%	71.8%
	Beyond 20 miles	0.0%	11.7%	11.7%	11.7%	16.5%	
	Column Total	0.0%	11.7%	24.8%	33.2%		100.0%
South East	Within 5 miles	1.1%	1.1%	1.1%	1.1%	0.0%	1.1%
	Within 10 miles	1.1%	1.1%	1.1%	1.1%	0.0%	1.1%
	Within 15 miles	1.1%	1.1%	1.1%	1.1%	0.0%	1.1%
	Within 20 miles	1.1%	1.1%	5.1%	5.1%	0.0%	5.1%
	Beyond 20 miles	55.3%	76.3%	91.3%	93.3%	1.6%	
	Column Total	56.5%	77.4%	96.5%	98.4%		100.0%
South West	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 20 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Beyond 20 miles	0.0%	0.0%	33.6%	34.0%	66.0%	
	Column Total	0.0%	0.0%	33.6%	34.0%		100.0%
Alaska Total	Within 5 miles	0.3%	0.3%	32.5%	33.2%	3.4%	36.6%
	Within 10 miles	0.3%	0.3%	34.4%	35.6%	3.4%	39.0%
	Within 15 miles	0.3%	0.3%	34.4%	35.6%	3.4%	39.0%
	Within 20 miles	0.3%	0.3%	35.6%	36.7%	8.8%	45.5%
	Beyond 20 miles	15.8%	23.5%	33.6%	34.2%	20.3%	
	Column Total	16.2%	23.8%	69.1%	70.9%		100.0%

Table 8.6: Summary of Usage Distribution of Potential Gas Usage of Oil and Diesel Fired Generation Units by Proximity to Sources of Natural Gas Supply (MMcf)

	Far North	Interior	South Central	South East	South West	Alaska
Within 5 miles of EPNGS	0	0	0	14,492	0	14,492
Within 5 miles of AHR	0	30,284	2,231	285	0	**32,800**
Within 10 miles of EPNGS	0	0	1,488	19,867	0	21,355
Within 10 miles of AHR	0	30,284	4,398	285	0	34,967
Within 15 miles of EPNGS	0	28,896	3,158	24,759	5,161	61,974
Within 15 miles of AHR	0	30,284	4,398	285	0	34,967
Within 20 miles of EPNGS	0	28,896	4,220	25,262	5,215	63,592
Within 20 miles of AHR	95	30,284	9,130	1,315	0	40,823
Beyond 20 miles of both	4,348	1,185	2,103	407	10,140	18,184

8.2: Electric Power Generation in the Interior

The electric power sector in Fairbanks has the potential for the largest use of ANS gas in the area. This sector includes Golden Valley Electric Association (GVEA), Aurora Energy, the University of Alaska Fairbanks, Ft Wainwright and Eielson AFB. The power plants for these facilities generate electricity from coal and fuel oil. GVEA is the largest power generator in the region. It operates two 60-megawatt oil-fired plants in North Pole plus several smaller, sub-station facilities. Golden Valley operates a coal-fired plant in Healy and owns partial interest in the Bradley Lake Hydro-electric facility.[9] Utility managers responded to a 1997 DNR survey regarding the potential for conversion to natural gas. The results of the survey are summarized in Table 8.7.

[9]GVEA obtained the electric customers and a diesel-fired combustion turbine from Fairbanks Municipal Utility System in 1997. Aurora Energy LLP (wholly owned by Usibelli Coal Mines (UCM)) was formed which took over Fairbanks Municipal Utility System's coal burning plant. GVEA contracted with Aurora Energy to purchase all electrical energy generated from these units. GVEA also purchases power directly from Chugach Electric Association, Inc. and Municipal Light and Power in Anchorage.

Table 8.7: Fairbanks North Star Borough Electric Power Survey

	Coal					Fuel Oil				
			Rate of Gas Consumption After Conversion					Rate of Gas Consumption After Conversion		
	Average Price Paid	Max Price for Conversion to Gas	Average	Seasonal Peak	Seasonal Low	Average Price Paid	Max Price for Conversion to Gas	Average	Seasonal Peak	Seasonal Low
	$/Ton	$/MmBtu	Mmcf/d	Mmcf/d	Mmcf/d	$/Gallon	$ per MmBtu	Mmcf/d	Mmcf/d	Mmcf/d
FMUS[1]	$44	$2.50	5	5	5	$0.71	$2.50	0.1	n/a	n/a
GVEA	$23.40	$1.50	7	7	7	$0.45	$2.50	12	14	10
FT. Wainwright	$46.22	$3.00	7.8	11.6	3.6	n/a	n/a	n/a	n/a	n/a
Eielson AFB	n/a	$3.60	6.4	12.8	5.01	n/a	n/a	n/a	n/a	n/a
UAF	$44	$2.82	2.5	3.2	0.5	$0.89	$6.34	0.14	1	0

[1] The Fairbanks Municipal Utility System assets were acquired by GVEA and Aurora Power in 1999.

In general, utility managers were receptive to a natural gas alternative to the low BTU coal. Several utility managers expressed a preference for having a choice among fuel feedstock. However, even if inexpensive, base-load natural gas were available on a sustainable basis, 100 percent plant conversion would be unlikely because of the high upfront investment, long-term contractual commitments with existing fuel suppliers, and the desirability of multiple fuel systems. Respondents indicated the maximum natural gas price that would compete with existing fuels and permit conversion ranges between $1.50 and $3.60 per MmBtu. An initial estimate of potential conversions based upon this survey, at different penetration rates for the year 2009, has been provided in Table 8.8

Table 8.8: Potential Natural Gas Usage for Power Generation in the Fairbanks North Star Borough in 2009

Line No		Formula		Low	Medium	High
1	**Electric Power - Civilian**[1]					
2	Projected Maximum Electricity Load (Bcf per Year)		10.3			
3	Penetration Rate in 2009[2]			25.0%	50.0%	83.0%
4	**Potential Civilian Electric Power Gas Usage in 2009 (Bcf/Yr)**	Line 2 x Line 3		**2.6**	**5.2**	**8.6**
5	**Electric Power - Military**[2]					
6	Projected Maximum Electricity Load (Bcf per Year)		2.7			
7	Penetration Rate in 2009[3]			25.0%	50.0%	83.0%
8	**Potential Military Electric Power Gas Usage in 2009 (Bcf/Yr)**	Line 6 x Line 7		**0.7**	**1.3**	**2.2**
9	**TOTAL FNSB AREA (Bcf per Year)**	Sum (Lines 4 & 8)		**3.3**	**6.5**	**10.8**

Table Notes:

[1] 83% based on Stone and Webster Engineering Corporation. *Railbelt Intertie Reconnaissance Study*, 1989.

[2] We assume that, at most, 50% of military electric power requirements would be available for gas-fired generation.

[3] Golden Valley Electric Association, Aurora Energy, and the University of Alaska Fairbanks.

Based on the results of this ADNR survey and other information, an alternative estimate of potential annual natural gas demand for electric power generation was prepared in Table 8.9. The results indicate that natural gas consumption for civilian electric power requirements could be approximately 9.3 Bcf per year. Military power requirements, which are served primarily with coal-fired generation, would be an additional 5.6 Bcf per year. The daily swings for heating use were assumed to be 2 ½ times the average usage rates, which is approximately the same as the maximum deliverability swings experienced in the Enstar system.

Table 8.9: Fairbanks Area Electric Power Plants and Estimated Natural Gas Usage[1]

	Golden Valley Electric Association	Aurora Energy, LLP	University of Alaska Fairbanks	Military[2]	Total
Coal Consumption					
Tons per Year	170,000	130,000	60,000	360,000	720,000
Million Btus per Year[3]	2,516,000	1,924,000	888,000	5,328,000	10,656,000
Oil Consumption					
Gallons per Year (x1000)	28,000		280		28,280
Million Btus per year[4]	3,948,000		39,480		3,987,480
Coal and Oil Combined Total MMBTUs	6,464,000	1,924,000	927,480	5,328,000	14,643,480
Natural Gas equivalent (Bcf per Year)	6.5	1.9	0.9	2.7	12.0
Non-Military			9.3		

[1] Estimated from published 1995 statistics, responses to a utility survey conducted by DNR in 1997 and private conversations with utility managers.
[2] Estimates, include Fort Wainwright and Eielson Air Force Base.
[3] Based on conversion: 1 ton of coal = 14.8 million Btus.
[4] Based on conversion: 1 gallon of heating oil = 141,000 Btus. Note that oil-fired power generation is highly variable.
[5] We assume that 50% of military power requirements would be available for gas-fired generation.

These above estimates are build on the maintained assumption that the cost of gas delivered to the power plants and the cost of furnace and generator system conversion to natural gas, would be competitive with other energy alternatives.

8.3: Gas by Wire Application

We also examine a new gas fired power generation facility near Fairbanks close to the AHR. In effect, we relocate regional gas-fired power generation to Fairbanks and distribute power *by wire* to communities in the Interior Region. For this analysis, we assumed a new 250 MW facility, at an installed cost of $750/kW. This facility was assumed to be operating at a heat rate of 6,000 BTUs per kWh generated. A power plant's heat rate measures its thermal efficiency in terms of the amount of BTUs of energy used to produce one kWh. The results of the analysis are presented in Table 8.10 below.

The results from the preliminary analysis are encouraging. Table 8.10 presents three different generation cost analyses based upon different fuel cost assumptions. We have examined new generation costs from a range taken by the three larger railbelt utilities with gas-fired generation. The top of the table includes the operating and cost assumptions used in the analysis. The bottom portion of the table presents two different cost estimates: total dispatch costs and total levelized costs.

Total dispatch costs are essentially the average variable costs of a generation facility and in most instances under economic (or least cost) dispatch, will dictate the order in which a power generation facility is run. Total levelized costs, on the other hand, are the total costs of the facility, including capital, expressed in per kWh term.[10] These costs are presented at the bottom of Table 8.10 and in all instances are relatively competitive from an absolute level.

[10]An annual carrying factor has been developed to estimate the return on and of the capital investment as well as any associated taxes.

Table 8.10: Total Dispatch and Levelized Cost for Gas By Wire Application

General Plant Cost and Operating Assumptions					
Capacity Factor	0.95			Annual Carrying Factor	12.81%
Total Annual Generation	2,080,500,000			Annual Carrying Cost	$22,414,158
Heat Rate	6,000			Total Capital Cost/kWh	$0.01077
Installed Capacity Cost ($/kW)	700			Deprecation, Years	30
Capacity (kW)	250,000			Rate of Return	10.16%
Total Installed Cost	175,000,000			Taxes	38.71%
Capital Cost; $/kW/Yr	23				
New Plant at MPL Gas Cost		**New Plant at CEA Gas Cost**		**New Plant at GVEA Gas Cost**	
Commodity Charge ($/MCF)	$1.86	Commodity Charge ($/MCF)	$1.27	Commodity Charge ($/MCF)	$3.18
Transportation Charge ($/MCF)	$0.00	Transportation Charge ($/MCF)	$0.00	Transportation Charge ($/MCF)	$0.00
Cost of Gas	$1.86	Cost of Gas	$1.27	Cost of Gas	$3.18
Total Annual Gas Cost	$23,218,380	Total Annual Gas Cost	$15,828,444	Total Annual Gas Cost	$39,711,544
Average Variable Fuel Cost	$0.01116	Average Variable Fuel Cost	$0.00761	Average Variable Fuel Cost	$0.01909
Average Variable O&M Cost	$0.00500	Average Variable O&M Cost	$0.00500	Average Variable O&M Cost	$0.00500
Total Dispatch Cost	$0.01616	Total Dispatch Cost	$0.01261	Total Dispatch Cost	$0.02409
Total Levelized Cost	$0.02693	Total Levelized Cost	$0.02338	Total Levelized Cost	$0.03486

Next, we compare the dispatch cost of the hypothetical, new generation facility with other railbelt utility generation facilities. The objective our our analysis is to explore how well the new gas-by-wire application compares with existing generating units from the standpoint of dispatch costs. In short run hourly power markets, generation facilities are dispatched according to short run marginal costs. This least cost dispatch ranks facilities from the lowest marginal cost to the highest marginal costs. Low cost units are typically run first, with higher cost units being dispatched up to the point where all demand is met.

Unit dispatch costs are usually comprised of average variable fuel costs as well as average variable operation & maintenance (O&M) costs. Unit dispatch costs, on a per MWh basis, are the sum of these two costs. The railbelt generation facilities, and their operating and cost characteristics, are presented in Table 8.11, with summaries given at the bottom for the Railbelt as a whole and the three major Southcentral electric utilities. The results for the new gas-by-wire applications are also shown at the bottom of Table 8.11. The results indicate that existing gas-fired generation in Alaska is relatively inefficient compared to a new gas-by-wire application. Heat rates, (or the thermal efficiency) of existing Railbelt gas fired generation ranges from 13,000 Btus/kWh to almost 16,000 Btus per kWh. New combined cycle generation typical generate at efficiencies of around 6,000 Btus per kWh. In making a comparison between these efficiencies, lower heat rates entail more efficient units. In other words, a lower heat rate entails that a unit uses less energy to make one kWh of electricity.

The new gas-by-wire application is competitive with many of these existing generation resources currently being dispatched in the railbelt utility system. In most every instance, the new gas-by-wire application beats existing gas-fired generation in the region.

A note of caution is in order at this juncture. We have concluded that under limited, short-run conditions, the new gas-by-wire application is more efficient and cost-effective than existing power generation. However, these estimates do not include the costs associated with supplying (transporting) the natural gas to the new gas-by-wire application, nor do they include any new power transmission costs associated with moving the electrical output from this facility. The costs of supplying natural gas to this potential application, as well as several others identified in earlier chapters of our report, are explored in Chapter 9. Our subsequent analysis will show that the new transportation (gas and power) infrastructure costs of putting this facility into service would shift the dispatch cost into the $28.42/Mwh to $36.34/MWh range.

Table 8.11: Railbelt Utility Generation Facilities Dispatch Cost Relative to Gas by Wire Application

Plant	Company	Fuel Type	Capacity (MW)	Maximum Capacity Factor	Equivalent Availability Factor	Fuel Cost	Heat Rate	Generation Amount	Fixed O&M	Variable O&M	Dispatch Cost
MLP Plant 1, Unit 1	MLP	Gas	16.8	97%	16	$1.86	14,590	142,752,960	$27.14	$2.00	$29.14
MLP Plant 1, Unit 2	MLP	Gas	16.8	97%	16	$1.86	13,980	142,752,960	$26.00	$2.00	$28.00
MLP Plant 1, Unit 3	MLP	Gas	19.5	97%	19	$1.86	14,371	165,695,400	$26.73	$2.00	$28.73
MLP Plant 1, Unit 4	MLP	Gas	34.1	97%	33	$1.86	17,324	289,754,520	$32.22	$2.00	$34.22
MLP Plant 2, Unit 5	MLP	Gas	38.4	97%	37	$1.86	10,106	326,292,480	$18.80	$2.00	$20.80
MLP Plant 2, Unit 7/6	MLP	Gas	109.5	97%	106	$1.86	8,527	930,443,400	$15.86	$2.00	$17.86
MLP Plant 2, Unit 8	MLP	Gas	87.6	97%	85	$1.86	11,577	744,354,720	$21.53	$2.00	$23.53
Beluga Unit 1	CEA	Gas	16.7	93%	16	$1.17	16,924	136,051,560	$19.80	$2.00	$21.80
Beluga Unit 2	CEA	Gas	16.7	98%	16	$1.17	17,320	143,366,160	$20.26	$2.00	$22.26
Beluga Unit 3	CEA	Gas	66.9	96%	64	$1.17	12,288	562,602,240	$14.38	$2.00	$16.38
Beluga Unit 5	CEA	Gas	71.0	97%	69	$1.17	12,537	603,301,200	$14.67	$2.00	$16.67
Beluga Unit 6	CEA	Gas	74.0	90%	67	$1.17	12,743	583,416,000	$14.91	$2.00	$16.91
Beluga Unit 7	CEA	Gas	74.0	95%	70	$1.17	13,172	615,828,000	$15.41	$2.00	$17.41
Beluga Unit 6-8	CEA	Gas	101.5	90%	91	$1.17	9,372	800,226,000	$10.97	$2.00	$12.97
Beluga Unit 7-8	CEA	Gas	101.5	90%	91	$1.17	9,149	800,226,000	$10.70	$2.00	$12.70
Bernice Lake 2	CEA	Gas	19.0	100%	19	$1.38	14,817	166,440,000	$20.45	$2.00	$22.45
Bernice Lake 3	CEA	Gas	28.0	93%	26	$1.38	13,512	228,110,400	$18.65	$2.00	$20.65
Bernice Lake 4	CEA	Gas	28.0	95%	27	$1.38	13,715	233,016,000	$18.93	$2.00	$20.93
International 1	CEA	Gas	15.0	90%	14	$1.38	15,992	118,260,000	$22.07	$2.00	$24.07
International 2	CEA	Gas	15.0	90%	14	$1.38	17,384	118,260,000	$23.99	$2.00	$25.99
International 3	CEA	Gas	19.0	89%	17	$1.38	15,030	148,131,600	$20.74	$2.00	$22.74
Soldotna 1	CEA	Gas	39.0	99%	39	$1.38	11,401	338,223,600	$15.73	$2.00	$17.73
Chena 6	GVEA	HAGO	29.0	95%	28	$3.40	12,256	241,338,000	$41.67	$0.30	$41.97
Zehnder EMD 5	GVEA	HAGO	2.6	99%	3	$3.21	25,679	22,548,240	$82.43	$8.24	$90.67
Zehnder EMD 6	GVEA	HAGO	2.6	99%	3	$3.21	27,679	22,548,240	$88.85	$8.24	$97.09
Zehnder GT 1	GVEA	HAGO	18.0	99%	18	$3.21	14,560	156,103,200	$46.74	$5.37	$52.11
Zehnder GT 2	GVEA	HAGO	18.0	99%	18	$3.21	14,560	156,103,200	$46.74	$5.37	$52.11
North Pole 1	GVEA	HAGO	56.7	95%	54	$3.00	9,751	471,857,400	$29.25	$4.80	$34.05
North Pole 2	GVEA	HAGO	59.3	92%	55	$3.00	9,154	477,910,560	$27.46	$4.80	$32.26
Healy 1	GVEA	Coal	25.0	91%	23	$1.36	13,995	199,290,000	$19.03	$11.20	$30.23
Healy D 1	GVEA	HAGO	2.6	95%	2	$3.21	11,451	21,637,200	$36.76	$8.24	$45.00
Bradley Lake -- GVEA	GVEA	Hydro	15.2	40%	6	$0.00	1	52,887,974	$0.00	$2.16	$2.16
Bradley Lake -- HEA	GVEA	Hydro	10.8	43%	5	$0.00	1	41,138,397	$0.00	$2.16	$2.16
Bradley Lake -- ML&P	MLP	Hydro	23.3	44%	10	$0.00	1	90,332,078	$0.00	$2.16	$2.16
Ekultna	MLP	Hydro	21.3	40%	9	$0.00	1	74,944,936	$0.00	$2.16	$2.16
Bradley -- Chugash	CEA	Hydro	40.7	42%	17	$0.00	1	151,283,658	$0.00	$2.16	$2.16
Ekultna Chugash	CEA	Hydro	18.7	37%	7	$0.00	1	61,318,108	$0.00	$2.16	$2.16
Cooper Lake 1	CEA	Hydro	8.6	33%	3	$0.00	1	24,529,402	$0.00	$0.21	$0.21
Cooper Lake 2	CEA	Hydro	8.6	33%	3	$0.00	1	24,529,402	$0.00	$0.21	$0.21
Railbelt Average				96%		$1.61	11,182				$24.89
MLP Average -- All Generation				98%		$1.46	10,663				$20.73
CEA Average -- All Generation				92%		$1.09	10,998				$15.66
GVEA Average -- All Generation				96%		$3.44	12,844				$43.82
MLP Average -- Gas Only				97%		$1.86	12,035				$26.94
CEA Average -- Gas Only				94%		$1.37	13,809				$18.44
GVEA Average -- Gas Only				97%		$3.48	12,639				$46.86
New Gas-By Wire Application -- MLP Gas Cost				98%		$1.86	8,680				$16.16
New Gas-By Wire Application -- CEA Gas Cost				93%		$1.37	8,968				$12.61
New Gas-By Wire Application -- GVEA Gas Cost				96%		$3.48	8,680				$30.09

CHAPTER 9: COST ESTIMATES OF SUPPLYING NATURAL GAS TO NEW OR EXPANDED SERVICE OPPORTUNITIES

9.1: Introduction

In the earlier chapters of our report, we identified a number of new opportunities for increased in-state natural gas usage. The objective of this chapter is to explore a number of these narrowly defined opportunities. In particular, we examine the cost side of the picture: what it would take to provide ANS gas energy services to in-state users. This refers primarily to the infrastructure requirements for providing energy services connected with the ANS gasline to various locations throughout the state. While many of these opportunities are important, many were spread throughout remote regions of the state and were of relatively small volumes. In these instances, the infrastructure requirements to serve these areas would be substantial and swamp the benefits of fuel switching.

There are a number of important issues conditioning the supply of natural gas to new usage opportunities throughout the state. These include:

- Relatively small demand volumes spread over remote areas;
- Distance between AHR and community;
- Required new investments to take high pressure and high Btu gas from the AHR pipeline; and
- Climate and environmental considerations.

Despite these challenges, earlier chapters of our analysis did identify a number of concentrated opportunities for increased in-state usage that warrant further investigation. These concentrated opportunities include:

(1) Natural gas usage for residential and commercial customers in the Interior region (Fairbanks);

(2) Power plant fuel switching in the Interior region (Fairbanks);

(3) Gas-fired central station generation with electricity being transmitted to the Interior region (gas-by-wire to Fairbanks); and

(4) Expanded gas usage from the existing LDC system in Southcentral region (Cook Inlet).

In the following subsections, we estimate the cost of supplying these regions/applications with ANS gas. These estimates are preliminary. Our

analysis has attempted to use the best available information to estimate the cost of supplying each of these opportunities. As most Alaskans are aware, the costs of developing major infrastructure projects in the state are heavily influenced by geography and climate. Any final conclusions about these infrastructure costs should be subject to a detailed engineering and environmental impact analysis.

9.2: Supplying ANS Gas to the Interior for Residential and Commercial Use

As noted in Chapter 6, there appears to be significant and relatively concentrated opportunities for natural gas usage in the Interior section of the state, primarily in the Fairbanks region. Our earlier analysis identifies close to 2 Bcf of potential residential use, and 2.1 Bcf of commercial use,[1] in this region. In order to supply natural gas to these areas, a number of new infrastructure investments would have to be made. The major infrastructure investments that we modeled included:

(1) Tap and meter station off the AHR pipeline that would reduce gas pressure and remove natural gas liquids for retail quality gas.

(2) Pipeline transportation investments to move the AHR gas from the major pipeline to the city gate.

(3) Distribution system investments including mains and lines to serve the local communities with new gas service.

In addition to the capital investments to supply ANS gas to the region, there are also ongoing administrative and general (A&G) and operation and maintenance (O&M) expenses associated with each of the investments described above. Lastly, commodity cost of gas will also have to be added to the cost of providing service to derive an estimated system average retail rate for serving these new sources of usage.

A number of our gas transportation and distribution assumptions are based upon an earlier conducted study by Stone and Webster (S&W) Engineering. This study examined the natural gas transportation and distribution costs of moving gas from the Cook Inlet to Fairbanks.[2] Meter station/processing costs have come from industry sources. Costs from the earlier S&W study were inflated to 2000 dollars. Transportation costs from the ANS Conditioning plant to the Fairbanks metering station, were based upon an assumed value that encompasses a range of prior studies on this issue.

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[1]This assumes 100 percent commercial penetration.

[2]Stone and Webster Engineering. *Estimated Cost and Environmental Impacts of a Natural Gas Pipeline System Linking Fairbanks with Cook Inlet Area.* Prepared for Alaska Power Authority. Jan. 1989.

Costs for each of the applications we consider in this section were first standardized in order to "price-out" each application. For instance, applications were identified by customers, distance (miles), and volumes. Total transmission costs were estimated from typical transmission costs on a per mile basis, from industry sources.[3] These costs were then multiplied by the mileage in each application. Distribution costs from the S&W study were inflated., and standardized on a per customer basis. The number of customers in each application was then applied to this distribution cost per customer. Capital costs for transmission and distribution were estimated based upon a 10.1 percent allowed return on investment, taxes, and straight-line depreciation for an assumed 30-year life for the assets.

Transmission, meter station, and distribution O&M costs were standardized to a cost per volume figure, and based upon typical gas company costs per Mcf. Volumes utilized by each application were then multiplied by these O&M costs per Mcf to derive total annual O&M costs. Lastly, gas acquisition costs were taken from the 1999 reported value for Enstar.

The next step in our cost analysis was to develop an average rate for each of these unbundled costs (i.e., meter/step down costs, transmission, distribution). Each of the total cost estimates discussed above were divided by total projected volumes to serve as a proxy for an average tariff rate. Our supply analysis of retail gas to the Fairbanks/Interior region is presented in Table 9.1.

[3]We compared our estimated transmission pipeline costs per mile to those published by Oil and Gas Journal in its annual pipeline economics survey. Our estimated costs per mile ($826,000/mile) were well within the range of costs provided for land-based projects, which ranged from a low of $820,000 per mile to a high of $925,000 per mile for 16 inch pipe. See *Oil and Gas Journal*, Pipeline Economics Survey, Volume 99.36: (September 3, 2001), 76

Table 9.1: Estimated System Delivered Cost for Interior (Fairbanks) Region

Fairbanks System Cost per Mcf	
Transportation – ANS Conditioning Plant to Fairbanks Meter Station	$1.0000
Levelized Meter/Step-Down Capital Cost	$0.0307
Levelized Transportation Cost	$0.0307
Levelized Distribution Costs	$1.2538
Transportation Meter Station O&M	$0.0545
Transportation O&M	$0.1091
Distribution O&M	$1.4857
Total T&D Cost	$3.9646
Commodity Cost	$1.9100
Total Delivered Cost (Average Retail Rate)	$5.8746

Table 9.1 presents the summary results and the estimated system average retail rate for providing retail gas service to the Fairbanks/Interior region. Our modeled distribution system includes 2.27 Bcf of residential annual gas usage (11,075 customers) and 2.1 Bcf of commercial usage (1,291 customers)[4] under 80 percent penetration of potential regional natural gas load.

Our estimated average retail rates assume that the entire load will shift from its existing fuel source to natural gas. For residential customers, the major fuel switching opportunities include using natural gas for space and water heating. Table 9.2 provides a general examination of the potential savings associated with moving consumption from current fuel sources to natural gas. Annual Btu loads and household expenditures are provided and come from the most recent US Department of Energy Residential Energy Consumption Survey (RECS) for households living in areas with greater than 7,000 heating degree days (HDDs).

[4]Assumes 10,300 square feet per typical commercial establishment from the U.S. Department of Energy, Energy Information Administration, *Commercial Buildings Energy Consumption Survey*.

Table 9.2: Estimated Total Bills for Residential Space and Water Heating by Fuel Type – Interior Region

	Annual Average Consumption per Household	Natural Gas Cost Per Household	Fuel Oil Cost Per Household	Electricity Cost Per Household	LPG Cost Per Household	Kerosene Cost Per Household
Space Heating	158.01	$928	$1,149	$1,222	$2,245	$738
Water Heating	39.20	$230	$285	$303	$557	$183
Total	197.21	$1,159	$1,434	$1,525	$2,802	$921

Table 9.2 examines the cost of new gas service versus other primary fuels used for space and water heating. Fuel oil is the predominant fuel for residential space and water heating, followed by electricity. There is about a 20 percent discount by moving from fuel oil to natural gas. There is a 27 percent discount by moving from electricity to natural gas for the typical household total bill. Total annual savings would be approximately $275 for households switching from fuel oil to natural gas.

Obviously, there would be conversion costs associated with natural gas furnace and appliance replacement. The rows in Table 9.3 provide various fixed levels of potential investments for furnace and appliance switching. Simple pay backs, based upon estimated annual savings from shifting current primary fuels to natural gas, are presented in each of the columns. As seen in Table 9.3, it would take about 3.6 years to pay off a $1,000 of space and water heating conversions/replacements for customers switching from fuel oil to natural gas.

Table 9.3: Simple Pay-Backs for Fixed Conversion Costs – Interior Region (Number of Years)

Fuel Switching Costs	Natural Gas Vs Fuel Oil	Natural Gas Vs Electricity	Natural Gas Vs LPG	Natural Gas Vs Kerosene
$100	0.4	0.3	0.1	-0.5
$250	0.9	0.7	0.2	-1.3
$500	1.8	1.4	0.3	-2.6
$750	2.7	2.0	0.5	-3.9
$1,000	3.6	2.7	0.6	-5.3
$1,200	4.4	3.3	0.7	-6.3

Our conclusions, based upon this very general cost analysis, are that serving natural gas to these communities may be possible. Some industry sources we consulted during the course of this investigation noted that savings in the 10 to 20 percent range are usually considered important in getting residential and small commercial customers to switch. Our estimated savings, under the reasonable optimistic scenario (i.e., 80 percent penetration rate), are around 20 percent for switching from fuel oil to natural gas and about 24 percent for switching from electricity to natural gas. However, these savings are based upon generalized cost assumptions of serving new areas and should be viewed as such.

9.3: Supplying ANS Gas to the Interior for Power Plant Fuel Switching

As noted in Chapter 8, there are a number of fuel switching opportunities for power plants in the Interior region. From our GIS analysis, we identified close to 200 MWs of power generation capacity that utilizes fuel oil or diesel as a primary fuel. These plants, and their operating characteristics and costs, are presented in Table 9.4. This table identifies each unit, the date it was placed into service, its current age, its prime mover by technology, primary fuel, and heat rate (i.e., amount of Btus required to generation one kWh of electricity.)

Table 9.4: Possible Fuel Switching Interior Power Plants

Utility Name	Plant Name	Unit	Capacity (kW)	Prime Mover	Primary Fuel	In Service Year	Plant Age	Estimated Heat Rate	Average Variable Cost per kWh
Alaska Power Co	Tok	3A	1,320	IC	FO2	1999	2	13,000	$0.0677
Alaska Power Co	Tok	4A	1,135	IC	FO2	1989	12	15,000	$0.0782
Alaska Power Co	Tok	5A	1,140	IC	FO2	1996	5	13,000	$0.0677
Alaska Power Co	Tok	7	1,250	IC	FO2	1984	17	15,000	$0.0782
Alaska Power Co	Tok	8	440	IC	FO2	1985	16	15,000	$0.0782
Alaska Power Co	Tok	9	930	IC	FO2	1985	16	15,000	$0.0782
Alaska Power Co	Dot Lake	1	125	IC	FO2	1990	11	13,000	$0.0677
Alaska Power Co	Chistochina	1	100	IC	FO1	1991	10	13,000	$0.0677
Alaska Power Co	Chistochina	2B	85	IC	FO1	1999	2	13,000	$0.0677
Alaska Power Co	Mentasta	1A	60	IC	FO2	1993	8	13,000	$0.0677
Alaska Power Co	Mentasta	2	100	IC	FO2	1992	9	13,000	$0.0677
Alaska Power Co	Mentasta	3A	90	IC	FO2	1996	5	13,000	$0.0677
Golden Valley Elec Assn Inc	Chena	6	23,100	GT	FO2	1976	25	18,000	$0.0938
Golden Valley Elec Assn Inc	North Pole	1	64,700	GT	FO4	1976	25	18,000	$0.0938
Golden Valley Elec Assn Inc	North Pole	2	64,700	GT	FO4	1977	24	18,000	$0.0938
Golden Valley Elec Assn Inc	Fairbanks	5	2,600	IC	FO2	1970	31	18,000	$0.0938
Golden Valley Elec Assn Inc	Fairbanks	6	2,600	IC	FO2	1970	31	18,000	$0.0938
Golden Valley Elec Assn Inc	Fairbanks	GT1	17,600	GT	FO2	1971	30	18,000	$0.0938
Golden Valley Elec Assn Inc	Fairbanks	GT2	17,600	GT	FO2	1972	29	18,000	$0.0938
Golden Valley Elec Assn Inc	Healy	IC1	2,500	IC	FO2	1967	34	28,500	$0.1485

IC = Internal Combustion

GT = Combustion Turbine

The analysis of power plant fuel switching costs is similar to the preceding analysis of Interior region retail service opportunities. The results have been presented in Table 9.5. First, we estimated the costs of serving these facilities with natural gas. Total transportation costs were developed in a fashion similar to that for the Interior section. Transmission costs were developed on a per mile basis, distribution costs were assumed to incur only half of the capital investment per customer as traditional residential and commercial customers, step-down and meter station costs were also included. Annual transmission and distribution O&M were taken from the estimated utilized earlier.

All costs were then rolled into an overall estimated tariff (average) rate. This rate can be thought of as a delivered rate of gas since it includes the commodity portion of the gas costs in addition to the transportation amount. Commodity gas costs were based upon the 1999 annual gas costs of $1.74 per Mcf. The column entitled "fuel savings" estimates the total cost savings on a per kWh basis associated with shifting fuel from fuel oil to natural gas. For most generating units, the annual average savings ranges from four-tenths to nine-tenths of a cent.

The second cost we examined included the capital expenditures required to convert these facilities to natural gas. These costs range between $2 to $5 per installed kW of capacity. The column entitled "total conversion costs" provides these estimates. These costs were then converted to a per kWh basis and backed out of the gross savings discussed above. The column entitled "net fuel savings" includes the capital expenditures associated with putting in fuel conversion equipment. Total annual average savings range from 0.87 cents per kWh to 0.36 cents per kWh (i.e., less than one cent per kWh).

These savings, multiplied by the average annual generation level for each facility, yields a total annual savings per facility. This is presented in the column entitled "total net savings." Total per facility savings range from a high of $2.8 million per year, to a low of $1,800 per year. However, the savings are based upon estimates that pipeline infrastructure is laid to the region for converting <u>all</u> eligible power applications. Hence, these figures cannot be taken individually per facility. The estimates are on a per facility basis assuming the infrastructure costs are spread across the volumes for eligible applications. Dropping one or two facilities, for instance, would drive up gas transmission and distribution rates, and effect the economics of fuel conversion for the remaining applications.

Table 9.5: Potential Savings from Fuel Switching Power Plants in the Interior Region

Utility Name	Plant Name	Unit	Capacity (kW)	Estimated Heat Rate	Current Fuel Cost ($/kWh)	Gas Fuel Cost ($/kWh)	Gas Transport ($/Mcf)	Gas Fuel Cost with Transport ($/kWh)	Fuel Savings ($/kWh)	Total Conversion Cost	Net Savings ($/kWh)	Total Net Savings
APC	Tok	3A	1,320	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$8,600	$0.00364	$40,019
APC	Tok	4A	1,135	15,000	$0.07815	$0.02610	$3.14355	$0.07325	$0.00490	$5,675	$0.00430	$40,577
APC	Tok	5A	1,140	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$5,700	$0.00364	$34,562
APC	Tok	7	1,250	15,000	$0.07815	$0.02610	$3.14355	$0.07325	$0.00490	$6,250	$0.00430	$44,689
APC	Tok	8	440	15,000	$0.07815	$0.02610	$3.14355	$0.07325	$0.00490	$2,200	$0.00430	$15,730
APC	Tok	9	930	15,000	$0.07815	$0.02610	$3.14355	$0.07325	$0.00490	$4,650	$0.00430	$33,248
APC	Dot Lake	1	125	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$625	$0.00364	$3,790
APC	Chistochina	1	100	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$500	$0.00364	$3,032
APC	Chistochina	2B	85	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$425	$0.00364	$2,577
APC	Mentasta	1A	60	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$300	$0.00364	$1,819
APC	Mentasta	2	100	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$500	$0.00364	$3,032
APC	Mentasta	3A	90	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$450	$0.00364	$2,729
GVEA	Chena	6	23,100	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$115,500	$0.00528	$1,014,118
GVEA	North Pole	1	64,700	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$323,500	$0.00528	$2,840,409
GVEA	North Pole	2	64,700	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$323,500	$0.00528	$2,840,409
GVEA	Fairbanks	5	2,600	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$13,000	$0.00528	$114,143
GVEA	Fairbanks	6	2,600	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$13,000	$0.00528	$114,143
GVEA	Fairbanks	GT1	17,600	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$88,000	$0.00528	$772,662
GVEA	Fairbanks	GT2	17,600	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$88,000	$0.00528	$772,662
GVEA	Healy	IC1	2,500	28,500	$0.14849	$0.04959	$3.14355	$0.13918	$0.00930	$12,500	$0.00870	$181,067
Total												$8,875,417

The analysis presented in Table 9.5 is based upon generalized assumptions about plant operating characteristics. In order to determine the outer possibilities for gas usage at these facilities an average operating capacity factor of 95 percent was assumed. This level may be unrealistically high. Table 9.6, however, presents a range of different cost savings and fuel usage at various different average capacity utilization factors.

Table 9.6: Cost Savings from Fuel Switching Under Different Average Capacity Factor Assumptions.

Capacity Factor	Gas Usage (Mcf)	Savings Per kWh		Total Savings
		Low	High	
95%	30,284,049	0.00360	0.00870	8,875,417
75%	23,908,460	0.00350	0.00850	6,794,093
50%	15,938,973	0.00310	0.00820	4,192,437
25%	7,969,487	0.02000	0.00700	1,590,781

9.3.1: Gas By Wire Application – Power to the Interior: Another potential new gas usage opportunity that we identified in an earlier chapter of our report was a gas by wire application. This application includes placing a central station power generation facility close to the AHR step-down meter station near Fairbanks (say), then transmitting the electricity (fueled by natural gas) to the Interior region of the state. The advantages of this opportunity include generating electricity with a more efficient, state of the art natural gas fired power generation facility. In addition, some gas distribution costs, which have been the more expensive costs associated with moving ANS gas to local communities, can by avoided.

The disadvantages of the gas by wire application is that, without substantial growth in electricity demand, the addition of new power generation facilities prior to 2014 could displace existing plants. The remaining costs associated with these displaced units would have to be recovered. Since most utilities in Alaska are publicly owned, ratepayers and shareholders are in the same group. Developing creative policies for recovering these costs would be needed.

Our gas by wire application considers the cost of transportation from ANS to the tap location near the AHR pipeline. We also include meter station and tap costs, as well as a small amount of transportation costs (we assume facility is located within one mile). In addition, we examined the cost of moving power from the generation facility, located in close proximity to the AHR, to the Interior region.

We have assumed that a 345 kV power transmission line would be developed to move gas from the power plant to the Interior section. Substation costs at the plant, and at the distribution system, are also included. The results from our analysis are presented in Table 9.7.

Once the costs of transportation (gas and power) are included in the total cost of dispatching new gas fired electricity, the new power application becomes less attractive. The total dispatch cost increases from between 50 percent to almost 100 percent depending upon the fuel cost assumptions examined.

At $28.41/MWh, the gas-by-wire dispatch costs under the MPL fuel cost assumption is higher than the average gas generation dispatch cost for MPL ($26.04/MWh, see Table 8.8 in Chapter 8). At $24.86/MWh, the gas-by-wire dispatch costs under the CEA fuel cost assumption is considerably higher than the average gas-fired CEA generation cost of $15.60/MWh. However, even at $36.34/MWh the gas-by-wire dispatch cost is competitive with the average gas fired generation cost of GVEA which is estimated to be $43.62/MWh.

We would conclude that, given the relatively higher cost in the GVEA region, there may be some potential applications for a gas-by-wire application that moved electricity into the interior. A more detailed study on power and gas transmission costs, however, would be necessary to draw definitive conclusions.

Table 9.7: Gas By Wire Application, Dispatch and Levelized Cost with Power and Gas Transmission

General Plant Cost and Operating Assumptions					
Capacity Factor	95%			Annual Carrying Factor	12.81%
Total Annual Generation	2,080,500,000			Annual Carrying Cost	$22,414,158
Heat Rate	6,000			Total Capital Cost/kWh	$0.01077
Installed Capacity Cost ($/kW)	$700				
Capacity (kW)	250,000			Deprecation, Years	30
Total Installed Cost	$175,000,000			Rate of Return	10.2%
Capital Cost; $/kW/Yr	$23.33			Taxes	38.7%
New Plant at MPL Gas Cost		**New Plant at CEA Gas Cost**		**New Plant at GVEA Gas Cost**	
Commodity Charge ($/MCF)	$1.86	Commodity Charge ($/MCF)	$1.27	Commodity Charge ($/MCF)	$3.18
Transportation Charge ($/MCF)	$1.06	Transportation Charge ($/MCF)	$1.06	Transportation Charge ($/MCF)	$1.06
Cost of Gas	$2.92	Cost of Gas	$2.33	Cost of Gas	$4.24
Total Annual Gas Cost	$36,474,010	Total Annual Gas Cost	$29,084,074	Total Annual Gas Cost	$52,967,174
Average Variable Fuel Cost ($/kWh)	$0.01753	Average Variable Fuel Cost ($/kWh)	$0.01398	Average Variable Fuel Cost ($/kWh)	$0.02546
Average Variable O&M Cost ($/kWh)	$0.00500	Average Variable O&M Cost ($/kWh)	$0.00500	Average Variable O&M Cost ($/kWh)	$0.00500
Transmission Rate ($/kWh)	$0.00588	Transmission Rate ($/kWh)	$0.00588	Transmission Rate ($/kWh)	$0.00588
Total Dispatch Cost ($/kWh)	$0.02842	Total Dispatch Cost ($/kWh)	$0.02486	Total Dispatch Cost ($/kWh)	$0.03634
Total Levelized Cost ($/kWh)	$0.03919	Total Levelized Cost ($/kWh)	$0.03564	Total Levelized Cost ($/kWh)	$0.04712

9.4: ANS Gas Opportunities in the Southcentral Region

9.4.1: The Natural Gas Supply and Demand Balance in the Cook Inlet Basin: Cook Inlet has been an active oil and gas basin since the discovery of the Swanson River Field in 1957. By the late 1960s nine major oil or gas fields containing nine trillion cubic feet (TCU) of gas had been discovered in the Cook Inlet Basin.[5] Two gas-feed industrial plants and a gas pipeline transmission system linking the Kenai Peninsula to Anchorage were fully operational by 1969.

In June of 1972, the Alaska Oil and Gas Conservation Commission passed a gas conservation order that required gas producers to minimize gas flaring. Over the intervening 25 years, the Cook Inlet Basin was able to deliver gas in quantities equal to or greater than the total usage among all customer classes. The Phillips-Marathon LNG plant and the Unocal Ammonia-Urea plant enjoyed an abundance of inexpensive baseload gas. Their investments in gas production facilities and pipeline infrastructure enhanced deliverability and lowered gas costs for residential and commercial users in Southcentral Alaska. Historic gas consumption by major customer classification is shown for the period 1971 through 2000 in Figure 9.1. Over the past five years, industrial users consumed approximately two-thirds of total gas dispositions. Residential and commercial users account for the other one-third.

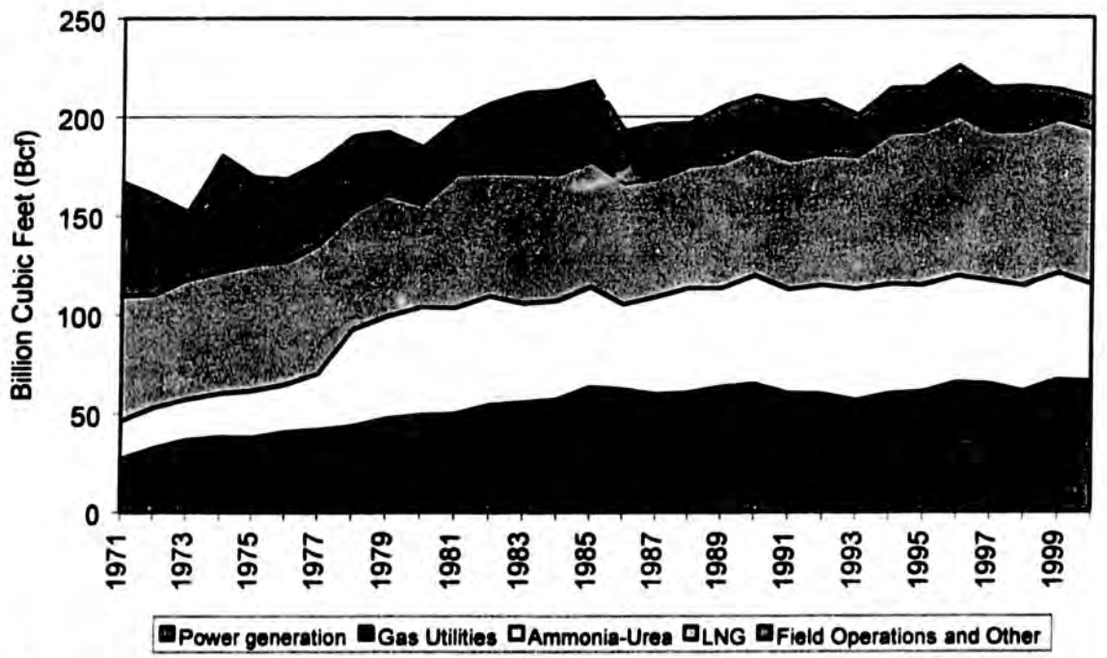

Figure 9.1: Cook Inlet Historic Gas Consumption by Major Disposition Category, 1971-2000

[5]Including Swanson River oil field and the Kenai (2.467 Tcf), North Cook Inlet (2.337 Tcf), McArthur River (1.377 Tcf), and Beluga (1.257 Tcf), plus several smaller gas fields.

December 1996 marked the end of the era of excess gas supply in the Cook Inlet Basin. At that time, Phillips and Marathon filed an application with the U.S. Department of Energy to renew and extend their license to export LNG to Japan. Coincidentally, a deep, winter cold snap in the Southcentral region and a compressor failure on the Steelhead platform resulted in abrupt but short-term gas curtailments to industrial plants. While the reasons and responsibilities for the industrial curtailments were disputed, the event itself signaled a transition to a new era of potential deliverability shortfall under extreme conditions of peak gas demand.[6] In April 1999 the DOE extended the Phillips-Marathon license to export until April 2009 but only after a protracted debate over existing and potential reserves estimates in the basin.[7] Estimates of booked reserves in the Cook Inlet Basin from the Alaska Department of Natural Resources currently stand at about 2.148 Tcf of natural gas.[8]

The debate over the Cook Inlet Basin gas supply and demand balance surfaced again in connection with a gas supply-purchase agreement between Unocal and Enstar, submitted to the Regulatory Commission of Alaska (RCA) in November 2000 The contractual agreement, approved with modifications by the RCA in October 2001, contains several provisions that fueled debate among stakeholders, including competing gas producers and consumer groups.[9]

For example, the agreement stipulates a pricing mechanism that links the wholesale gas price for Unocal deliveries to the daily average price of Henry Hub natural gas futures.[10] Indexing local gas prices to world commodity prices is, in itself not new to the Cook Inlet Basin. Numerous Cook Inlet gas supply agreements are indexed to world oil prices and to spot prices for fertilizer. This Unocal-Enstar pricing mechanism is unique because it is tied directly to a dominant Lower-48 *gas price marker*, the Henry Hub futures price. The pricing mechanism stipulates a three-year moving average for ". . . contract[s] traded

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[6]Gas curtailments were confined to industrial plants and occurred over a period of several days beginning on December 31, 1996. A subsequent legal dispute among gas producers over actions and responsibilities surrounding these curtailments has been settled. Phillips-Marathon and Unocal have gas exchange agreements in place to provide for orderly curtailments to industrial plants in the event that peak system-wide demand exceeds deliverability.

[7]Office of Fossil energy, *Order Extending Authorization to Export Liquified natural Gas From Alaska*, (Washington DC: U.S. Department of Energy, DOE/FE Opinion and Norder No. 1473), April 2, 1999.

[8]DNR, Division of Oil and Gas, *Historic and Projected Oil and Gas Consumption, 2000 Annual Report*, p. 13, 2000.

[9]Regulatory Commission of Alaska, *Order Conditionally Approving TA 117-4 (Gas Sales Agreement) and Requiring Filing*, (Docket No. U-01-7, Order No. 8), October 25, 2001.

[10]Also, it gives Unocal a first right of refusal to supply gas to meet Enstar undesignated supply for up to 450 Bcf. No explicit time limitations were placed on the contract even though RCA's Public Advocacy Staff recommended a nine year contract term. In its final order, the RCA left open the possibility of revisiting the terms of the contract once the 450 Bcf limitation was reached.

during the immediately previous thirty-six month period ended each September 30th of the year prior to the year for which the price is calculated" and a price floor equal to $2.75 per Mcf adjusted for changes in inflation.[11] Unocal is expected to begin making deliveries to the Enstar system under this agreement in 2004.

Figure 9.2 illustrates how the Unocal-Enstar pricing mechanism would work based on *back-casting* a three-year moving average of the monthly Henry Hub spot price during the historic period starting in December 1994.[12] Figure 9.2 compares Unocal-Enstar mechanism with the Alaska Department of Revenue Prevailing Value (DORPV).[13] Several points are noteworthy.

First, the DORPV exhibits an upward trend of approximately seven-tenths of a cent per year over the seven-year historic period. This upward trend is more pronounced after January 2000. Second, the long-term trend for the three year moving average of Henry Hub price is approximately twice that of the DORPV. Third, the 36-month moving average of Henry Hub spot price is on average $0.69 per Mcf higher than the DORPV over the same historic period. This difference becomes more pronounced after September 1998. Fourth, the price floor would have been in effect during much of the historic period, raising gas prices another $0.40 per Mcf, on average. The back-casting results indicate that the Unocal-Enstar price mechanism would have generated higher gas prices than those observed in the recent past in the Cook Inlet Basin.

Figure 9.2 also projects the Henry Hub price and the Unocal-Enstar pricing mechanism based on U.S. Department of Energy, Energy Information Administration forecast of domestic gas prices.[14] Although dispositions under the Unocal-Enstar agreement are not expected to occur until 2004, the pricing provisions in this agreement signal a discrete change in local gas prices at the wholesale level – one that could be interpreted as a response to a prevailing local condition of excess demand for gas. Unocal and Enstar have suggested in testimony to the RCA that higher gas prices are necessary to stimulate exploration.[15]

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[11] *Gas Sales Agreement Between Union Oil Company Of California and Alaska Pipeline Company*, November 2000, p. 21-4. Note, the inflation adjustment is one half of the rate of inflation, measured as the Gross Domestic Product Implicit Price Deflator from the quarter ended June 2001.

[12] Note that the Unocal-Enstar mechanism would adjust once a year, rather than continuously, as reflected in the monthly data in Exhibit 2.

[13] The DORPV is based on a weighted average of gas dispositions to local utilities providing gas and electricity service.

[14] Energy Information Administration. Annual Energy Outlook 2002, Table 14, (Washington DC: U.S. Department of energy), December 2001. Note, the EIA forecast is for average Lower-48 wellhead price. 17 cents per mcf was added to the EIA estimate to approximate the Henry Hub price, based on the historic difference between Henry Hub and EIA estimate for average wellhead price.

[15] *Submittal of Union Oil Company of California's Prefiled Reply Testimony of Daniel B. Thomas, Patrick J. Coughlin and Richard F. Strickland Ph.D,PE.; Reply Testimony of Richard F. Barnes*; and *Reply testimony of Daniel M. Dieckgraeff*, Docket No. U-01-007, (July 27, 2001).

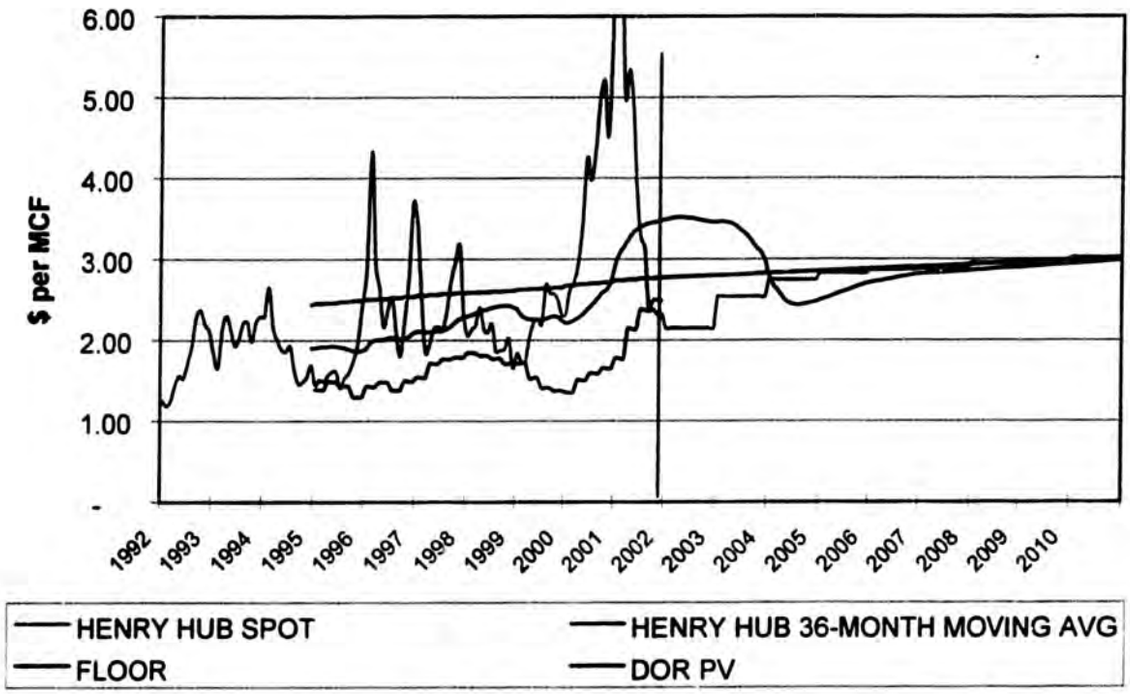

Figure 9.2: Henry Hub 36-Month Moving Average with UNOCAL-ENSTAR Price Floor
Henry Hub Spot Price and DOR Prevailing Value and Backcast: Jan 1992 - Dec 2001 and Forecast: Jan 2002 - 2010

Higher wholesale gas prices have mixed implications. They are expected to stimulate more exploration and lead to new gas discoveries. But also, they raise costs for industrial uses that depend on low-cost gas in order to compete in global markets. While the outcome of expected higher local gas prices is still uncertain, an aggressive program of oil and gas exploration in Cook Inlet was evident in 2001, as shown in Table 9.8. The implications of stepped up exploration for the gas demand-supply balance in the Cook Inlet Basin are illustrated in Figure 9.3 and Figure 9.4.

Assume that relative energy prices remain stable and the demand for Cook Inlet gas, including gas dispositions for LNG Exports, continues to grow at the steady pace outlined in the baseline forecast of Chapter 4. Assume further that production from the existing 2.148 Tcf reserves base continues along reasonable rates of decline for various producing fields. If no new discoveries of gas are forthcoming, then annual deliverability shortfalls can be expected by 2004 or 2005. One Tcf of reserves appreciation would provide a four-to-five year buffer and forestall annual deliverability shortfalls until around 2009.

In addition to one Tcf of added reserves, assume further that the license to export LNG to Japan is not extended beyond April 2009. This situation is illustrated in Figure 9.4. The abrupt fall in demand after 2009 reflects closure of the LNG plant. Here, annual deliverability shortfalls would not occur until after 2015.

These examples suggest that, while gas reserves for utility dispositions are relatively secure, industrial users of Cook Inlet gas have some exposure to the prospect of gas deliverability shortfalls, even when reasonable reserves additions are taken into account. Thus, over the long run, additional gas reserves beyond 1 Tcf will be required to provide continued gas service to industrial users in the Cook Inlet Basin.

Table 9.8: Cook Inlet Oil and Gas Exploration Activity, 2001

Unit or Project	Companies	Description
Ninilchik and Falls Creek	Marathon	G.O. #1 well completed as gas well, G.O. #2 well planned.
Pretty Creek Lewis River Ivan River	Unocal	Re-entered one well each in Lewis River and Ivan River; drilling P.C.U. #4, new well, in Pretty Creek Field.
South Ninilchik and Deep Creek	Unocal	Up to three wells planned on State and CIRI lands in 2001-02.
Swanson River Unit Gas Satellites Project	Unocal	Proposal to develop two gas fields north and east of Swanson River oil field on Federal and Native owned lands.
Redoubt	Forest Oil (discovered in 1968 by Pan Am)	R.U. #1, #2, & #3 wells completed by Forest; R.U. #4 is planned. Up to 193 MMBO recoverable reserves. Forest has other prospects at Sabre, Corsair, and Valkyrie.
Pioneer (Coalbed gas, no proven reserves)	Evergreen Exploration	Formerly operated by Ocean Energy, ownership and operations transferred to Evergreen in mid-2001. Two production wells and one injection well drilled in 1999; Evergreen is committed to drill six more wells, at least one in each of two new areas.
Cosmopolitan	Phillips (discovered in 1967 by Penzoil)	Hansen #1 well permitted to drill to bottom location on State lease.
Nikolai Creek	Aurora Gas	Production started in October; NCU #3 well produces at rate of 2 MMCF per day.
North Fork	Gas Pro	Project apparently on hold.
Trading Bay Unit/McArthur River Field (Oil)	Unocal	T.B.U. #K-13 came on production at 7,100 BOPD, highest rate of any well in Cook Inlet.

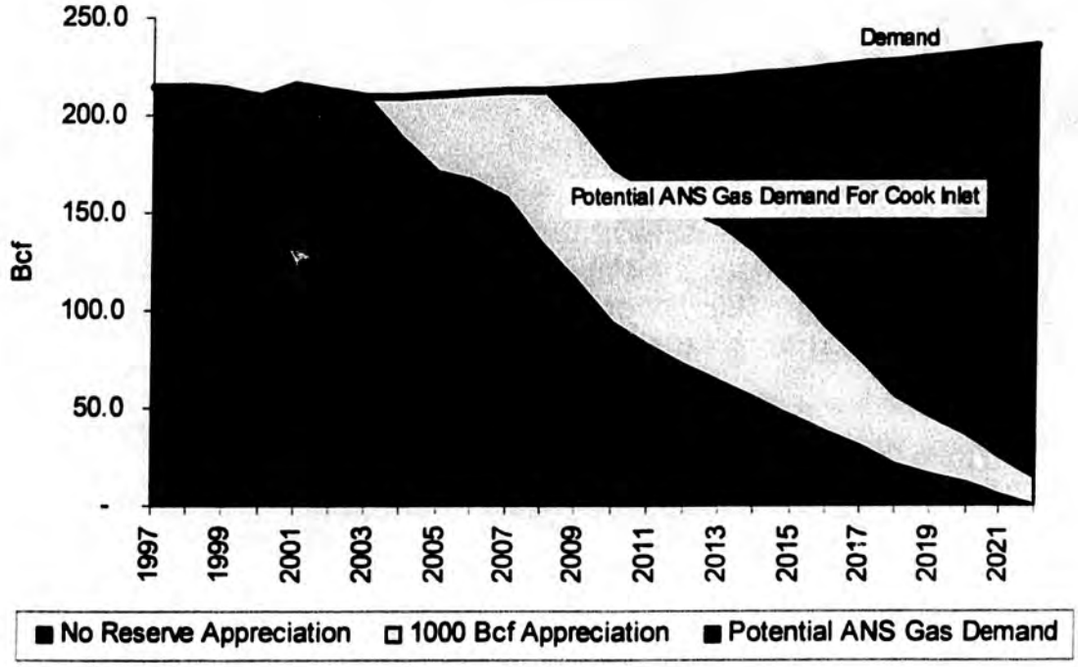

Figure 9.3: Projected Cook Inlet Supply and Demand
Typical Production Scenario with 1 Tcf Reserve Appreciation

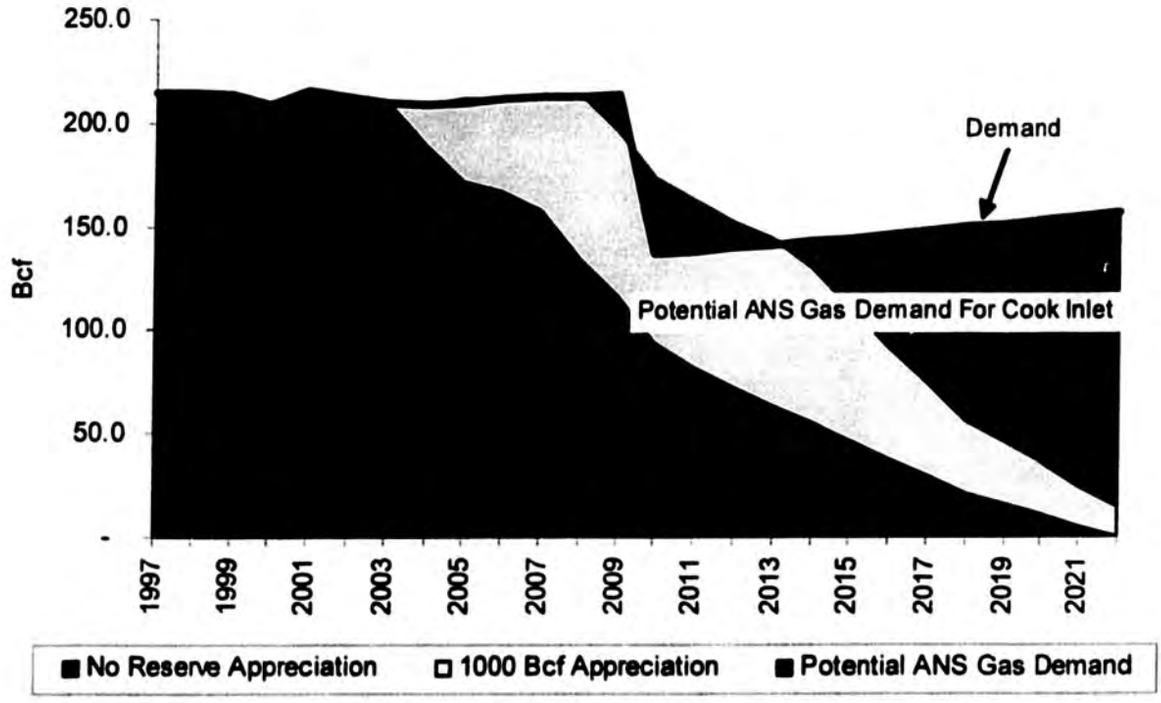

Figure 9.4: Projected Cook Inlet Supply and Demand
LNG Export License Renewal Denied

9.4.2: Retail Opportunities in the Southcentral Region: First, consider the implications for expanded gas usage for the Southcentral region, similar to that for the Interior region. We modeled a standardized system to serve the region's *new* natural gas usage. (We assume existing baseline consumption is supplied from existing sources in the Cook Inlet Basin.) The new system is comprised of 11,219 new remote residential customers and 2.2 Bcf of additional annual natural gas usage.

We examined two different opportunities for transporting the natural gas to the region. Our approach is to assume that a lateral spur pipeline from the AHR pipeline is constructed and considered part of the overall pipeline system for pricing purposes. This could entail some spreading of the costs of the system if a zonal based transportation tariff for the region were developed.[16]

We also modeled a system where the cost of the lateral spur was completely recovered from the Southcentral region and no other costs were spread to other out-of-region customers. The overall system average rates are presented in Table 9.9. If the cost of this spur is not spread across some broader region and are allocated only incremental expansion of new residential customer usage, the per-unit cost of moving ANS gas into the region would be prohibitive.

Table 9.9: Estimated System Average Retail Rate for Southcentral/Cook Inlet Region With Entire Spur Transportation Costs

Cook Inlet System – Separate Spur System Cost per MCF	
Transportation – ANS Conditioning Plant to Fbks Meter Station	$1.0000
Levelized Meter/Step-Down Capital Cost	$0.0477
Levelized Transportation Cost	$13.2203
Levelized Distribution Costs	$2.3655
Transportation Meter Station O&M	$0.0545
Transportation O&M	$0.1091
Distribution O&M	$1.4857
Total T&D Cost	$18.2828
Commodity Cost	$1.9100
Total Delivered Cost (Average Retail Rate)	$20.1928

[16]For example, to serve Interior Region gas-by–wire or expanded Interior Region residential and commercial usage. Our analysis showed that if the realized transportation rate was reduced by about $1.25 per Mcf, average retail rates would be around $7.27 per Mcf.

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The analysis presented above, is based on small, incremental gas service applications. As expected, many of the applications, given their limited volumes, either generate small, or negative net benefits. However, if volumes were increased, the large fixed costs associated with gas transportation, would decline on a per-unit basis to levels that may compete with alternative energy sources.

9.4.3: ANS Gas as a Means to Meet a Potential Supply/Demand Imbalance in the Southcentral Region: As noted earlier, one area of potential interest to DNR has been associated with supplying the Southcentral region with gas from the ANS given concerns about the availability of future supplies for the region. The RCA also appears to be concerned with this issue as well. In its recent Order conditionally approving Enstar's Gas Sales Agreement (GSA), the Commission noted:

> Natural gas reserves, while plentiful in the past, are declining. It is predicted that the known natural gas reserves in Cook Inlet will be exhausted by 2012. Exploration for new sources of gas in Cook Inlet has not kept pace with other areas. There is also concern that the older fields in the Cook Inlet will be unable to deliver natural gas at the rates required. The ability to meet peak demand may also be affected by the lack of gas storage facilities. Exploration and development of new natural gas sources takes many years and requires that exploration companies act years before reserves are exhausted by customer demand. [Regulatory Commission of Alaska. Order Number 8, Docket Number U-01-7, at 5.]

Given the preceding analysis of fixed and variables costs for gas step-down, transmission, and distribution, we consider the impact of greater throughput on the per transmission and delivered costs.

Table 9.10 presents estimates of the transportation costs associated with two different spur lines from Fairbanks to the Southcentral region: a 16-inch pipeline and a 20-inch pipeline. Discrete transportation/usage volumes are presented in the left hand column, while estimated levelized rates are presented for each volume level, for each type of pipeline. In order to put these volumes into perspective, the second and third columns of the table relate these volumes to total system, and Southcentral 1999 sales.

Table 9.10: Estimated Levelized Transmission Costs (Fairbanks to Southcentral) Under Different Volume Scenarios

10	21.9%	4.9%	$ 2.9412	$	3.6378
20	43.8%	9.8%	$ 1.4706	$	1.8189
30	65.7%	14.8%	$ 0.9804	$	1.2126
40	87.6%	19.7%	$ 0.7353	$	0.9095
50	109.4%	24.6%	$ 0.5882	$	0.7276
60	131.3%	29.5%	$ 0.4902	$	0.6063
70	153.2%	34.4%	$ 0.4202	$	0.5197
80	175.1%	39.4%	$ 0.3676	$	0.4547
90	197.0%	44.3%	$ 0.3268	$	0.4042
100	218.9%	49.2%	$ 0.2941	$	0.3638

**/1 Sales volumes are for retail customers only and do not include volumes that may be direct served.*

**/2 Enstar retail with Urea plant 1999 volumes of 53.9 Bcf, LNG volumes of 77.95 Bcf, and and gas generation volumes of 34.57 Bcf.*

**/3 Assumes 16 inch pipe at a cost of $826,018 per mile at 278 miles*

**/4 Assumes 20 inch pipe at a cost of $1.02 million per mile at 278 miles. 20 Inch pipe assumes a 45 million increase from total estimated cost (for 16 inch pipe) provided in S&W Study inflated to 2001 dollars.*

As seen from the table, in order to get the overall costs down to the $1/Mcf threshold, a 16-inch system would need to have volumes of around 30 Bcf and a 20-inch system would need to move volumes in the order of 40 Bcf per year. The 30 Bcf level is approximately 14.8 percent of estimated Southcentral 1999 sales volumes, while 40 Bcf is approximately 19.7 percent of total regional 1999 sales.

While increasing usage volumes can reduce the unit costs associated with transporting natural gas to the Southcentral region, it will not to lower distribution charges. One opportunity, however, may be to incorporate the higher than average costs associated with serving these new customers into the existing Enstar distribution system costs. In effect, existing Enstar customers would

subsidize the excess costs of expanding the current system to include the potential remote areas.

Based upon our estimates, the average non-gas related distribution costs for Enstar are approximately $1.55 per Mcf. This estimate comes from taking the Company's 1999 average retail rate and subtracting the total annual average gas acquisition cost. We estimate that taking the excess cost of the new system and averaging them into the combined distribution system costs and volumes yields a subsidy of approximately 3.8 cents per Mcf. However, we would note, while not large in magnitude, this type of cost-shifting policy would have to be deemed in the public interest, and approved, by the RCA.

Figure 9.5 graphs the various different estimated transportation costs for each modeled system under different volumetric assumptions.

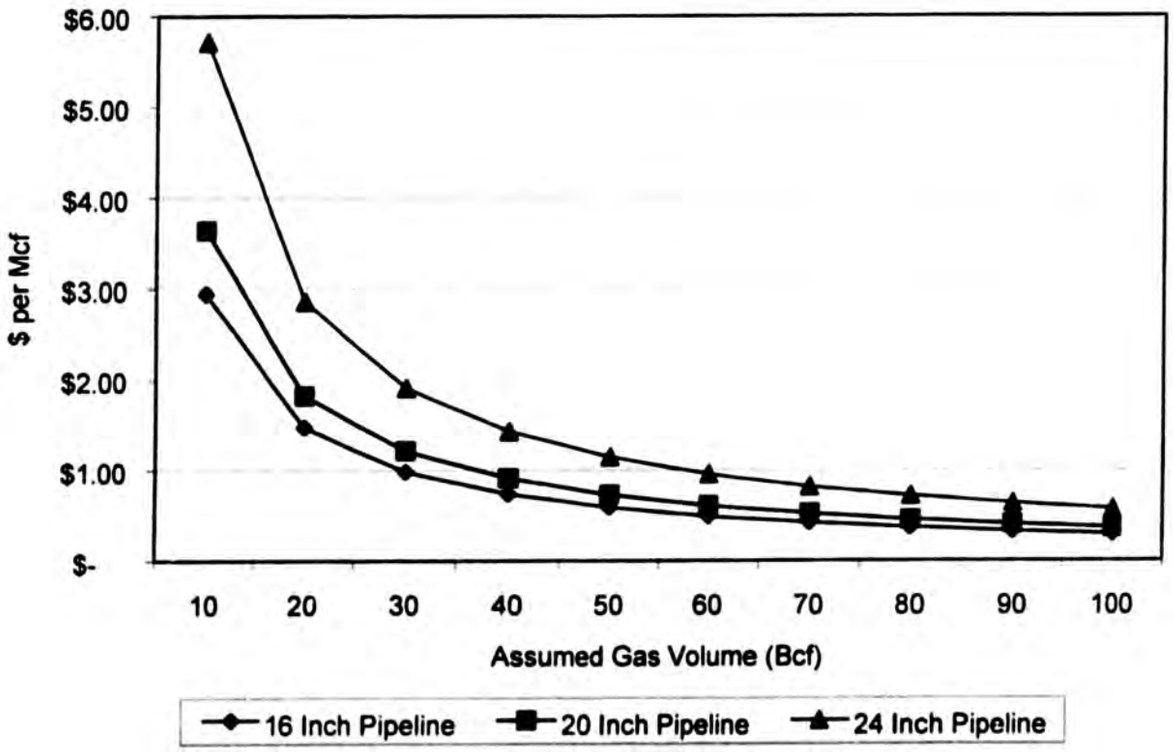

Figure 9.5: Estimate Pipeline Transportation Costs Under Different Volumetric Assumptions

Table 9.11 combines a number of the analyses discussed above for the 16-inch pipeline example. We have estimated total costs associated with providing service into the Southcentral region from a tap located near Fairbanks. Total transmission and distribution costs have been included. Distribution costs, in our example, are from the Enstar system, and include the subsidized portion (i.e., the 3.8 cents per Mcf) of serving the new 2.2 Bcf level of usage associated with remote residential customers. Table 9.11 presents cost estimates for a number of discrete volumes moved over the hypothetical transportation system.

The costs of moving gas, while more economic, are still relatively high relative to 1999 Enstar average rates. However, even with the higher transportation costs, average rates for this hypothetical new system still are below the national average for residential retail customers. The new system yields estimated rates that are between 17 percent to 33 percent below national averages, depending upon the volumes assumed. Even with the pipeline addition, and its increased costs, Alaskans still have the opportunity to pay rates below the national average. Again, we would offer some caution on the numbers. Until detailed engineering studies could be completed, no definitive conclusions can be attained.

Table 9.11: Analysis of Estimated Average Rates – Pipeline System from Fairbanks to Southcentral

Assuming 30 Bcf/y Volumes – 16 Inch System		Assuming 50 Bcf/y Volumes – 16 Inch System	
Transportation – ANS to Meter Station	$ 1.0000	Transportation – ANS to Meter Station	$ 1.0000
Levelized Meter/Step-Down Capital Cost	$ 0.0674	Levelized Meter/Step-Down Capital Cost	$ 0.0674
Levelized Transportation Cost	$ 0.9804	Levelized Transportation Cost	$ 0.4902
Transportation Meter Station O&M	$ 0.0545	Transportation Meter Station O&M	$ 0.0545
Transportation O&M	$ 0.1091	Transportation O&M	$ 0.1091
Distribution System Unit Cost	$ 1.5930	Distribution System Unit Cost	$ 1.5930
Total T&D Cost	$ 3.8044	Total T&D Cost	$ 3.3142
Commodity Cost */1	$ 1.9100	Commodity Cost */1	$ 1.9100
Total Delivered Cost	$ 5.7144	Total Delivered Cost	$ 5.2242
Enstar 1999 Residential Average Revenue	$ 3.6602	Enstar 1999 Residential Average Revenue	$ 3.6602
Percent Change	***56.1%***	***Percent Change***	***42.7%***
US Residential Average Rate (1999)	$ 6.6900	US Residential Average Rate (1999)	$ 6.6900
Alaska ANS Rate Relative to US Average	***-17.1%***	***Alaska ANS Rate Relative to US Average***	***-28.1%***
Assuming 80 Bcf/y Volumes – 16 Inch System		**Assuming 100 Bcf/y Volumes – 16 Inch System**	
Transportation – ANS to Meter Station	$ 1.0000	Transportation – ANS to Meter Station	$ 1.0000
Levelized Meter/Step-Down Capital Cost	$ 0.0674	Levelized Meter/Step-Down Capital Cost	$ 0.0674
Levelized Transportation Cost	$ 0.3676	Levelized Transportation Cost	$ 0.2941
Transportation Meter Station O&M	$ 0.0545	Transportation Meter Station O&M	$ 0.0545
Transportation O&M	$ 0.1091	Transportation O&M	$ 0.1091
Distribution System Unit Cost	$ 1.5930	Distribution System Unit Cost	$ 1.5930
Total T&D Cost	$ 3.1916	Total T&D Cost	$ 3.1181
Commodity Cost */1	$ 1.9100	Commodity Cost */1	$ 1.9100
Total Delivered Cost	$ 5.1016	Total Delivered Cost	$ 5.0281
Enstar 1999 Residential Average Revenue	$ 3.6602	Enstar 1999 Residential Average Revenue	$ 3.6602
Percent Change	***39.4%***	***Percent Change***	***37.4%***
US Residential Average Rate (1999)	$ 6.6900	US Residential Average Rate (1999)	$ 6.6900
Alaska ANS Rate Relative to US Average	***-31.1%***	***Alaska ANS Rate Relative to US Average***	***-33.1%***

Our preliminary findings indicate that the levelized cost of a 16-to-20 inch spur pipeline linking Southcentral with the ANS gas pipeline at Fairbanks could be competitive with energy alternatives (such as fuel oil or LNG imports into Cook Inlet) if annual throughput exceeds 30-to-40 Bcf per year. For example, a 20-inch spur pipeline operating at an average of 40 Bcf per year for 30 years would imply meter-station step-down charges and levelized transmission charges of approximately $1.00 per Mcf (excluding the toll to Fairbanks, as well as local distribution and gas commodity charges). In order to be competitive, the spur pipeline would be required to serve a segment of the existing Southcentral customer base now served by local gas reserves in the Cook Inlet Basin. This result could be favorably influence by scale economies resulting from:

- Sharing spur pipeline transmission charges over a wider customer base along the energy belt;
- Higher rates of penetration than those observed among Southcentral users within the existing ENSTAR system;
- System-wide averaging of distribution charges; and
- Baseline growth in all customer classes including industrial users and expanded gas service.

9.5: Conclusions

When viewed individually, few applications for supplying ANS gas for in-state usage "pencil-out." Savings from fuel switching are relatively small. There is no substantial need for new power generation until the year 2014. Opportunities for new industry and businesses, like the internet server farm and a new petrochemical facility, are speculative, at best.

One application that warrants further consideration is natural gas delivery into Interior region communities that are in proximity to the proposed AHR pipeline. Our initial results indicate that, on a stand-alone basis, sufficient concentration of residential and commercial space-heating demand exists in the greater Fairbanks area to enable local natural gas distribution to compete with fuel oil and other spacing-heating energy alternatives. When taken in combination with a lateral spur pipeline into Southcentral, the economics of providing gas service to Interior communities for space heating, electric power generation and industrial applications could improve.

Moving gas to the Southcentral region is highly dependent upon future reserve development in the Cook Inlet Basin. Study results indicate that, in order to be competitive, spur line throughput must achieve volumes beyond levels that correspond to various individual and incremental gas usage applications considered in this study. Some portion of gas usage – 30 to 40 Bcf per year –

currently supplied by producing fields in the Cook Inlet Basin would be required to generate sufficient economies of scale. The declining rates of existing Cook Inlet fields, combined with the steady progression of demand in the Southcentral and Interior regions suggest that, even with the near-term discovery of one Tcf of additional Cook Inlet reserves, a supply shortfall of 30 to 40 Bcf or more per year is likely to occur sometime between 2009 and 2015. Thus, a lateral spur pipeline that delivers gas into the Southcentral region could provide a long-term, economic solution to the supply-demand imbalance projected for this area.

The decision of supplying ANS gas to Alaska communities should be left to the market. If reserves fall low enough in currently served regions, prices will have to increase to ration demand.[17] Once prices increase, signals will be sent to the market for the development of either new resources, or new means to bring other resources (i.e., ANS gas) to the region.

Higher prices, while signaling the market about important energy development opportunities, can also serve to send signals to critical, energy-intensive Alaskan industries to move elsewhere. In effect, a cycle is set up whereby higher prices are needed to stimulate infrastructure development, but these prices, in turn, discourage industrial development and retention, which in turn, shift the relative economics of infrastructure development. Reserves and infrastructure development on the supply side typically occur in discrete, lumpy amounts and are often not well balanced with demand. This raises project risk and adds to the challenges faced by resource-development and resource-consuming industries.

[17]The same would hold true for regions that are currently not served with natural gas. If prices for their current energy alternatives increase high enough, then opportunities for moving new energy resources in the region increase.

CHAPTER 10: CONCLUSIONS

The purpose of this report has been to examine opportunities for in-state natural gas usage in Alaska. As noted at the onset of this report, the approach taken to examine these opportunities was based upon the analysis of:

- Existing in-state demand and the development of a forecast to the year 2020.
- Forecast assumptions to determine how in-state demand could shift as a result of changing economic conditions.
- New service opportunities in remote and currently unserved areas of Alaska.
- New potential industries and their impact on in-state gas usage.
- Fuel switching opportunities for oil-fired generators as well as an examination of a central power generation station gas-by-wire application.
- The potential costs of supplying new usage opportunities with natural gas service.

The general findings from the analysis can be summarized as follows.

10.1: Baseline Forecast

Under the baseline forecast, retail natural gas usage is expected to show slow, but consistent, growth through the year 2020. Total usage will grow at an annual average rate of slightly under one percent. Residential customers will account for 28.5 percent of this growth, commercial customers will account for 22.7 percent of this growth, industrial customers will account for 28.9 percent of this growth, and electricity utilities will account for 19 percent of this growth. Table 10.1 presents a summary of the baseline usage levels for each major customer class.

Table 10.1: Summary of Baseline Forecast

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,518,229	28,566,567	73,238,676	35,656,886	154,980,358
2005	19,198,104	30,564,363	75,226,290	35,406,497	160,395,253
2010	21,059,031	31,531,308	77,214,690	37,031,714	166,836,744
2015	23,121,582	33,362,837	79,203,895	38,899,627	174,587,941
2020	25,409,386	34,837,741	81,193,900	40,790,982	182,232,010
10 Year Increase	3,540,802	2,964,742	3,976,015	1,374,828	11,856,386
20 Year Increase	7,891,157	6,271,174	7,955,225	5,134,096	27,251,652

Original Source Table: Chapter 4: Tables 4.1, 4.2, 4.3, and 4.4.

10.2: Sensitivity Analysis

Shifts in prices and income can have important impacts on natural gas usage. The impact that shifts in prices can have on usage is relatively more important than income. Under a high price scenario, total in-state annual average growth rates are reduced to about 0.75 percent, while under a low price scenario, annual average growth rates for total in-state usage are increased to 1.05 percent per year. Under a high-income scenario, we anticipate that total in-state usage will increase by an annual average rate of one percent. Under a low-income scenario, total in-state usage will grow by only three-quarters of a percent per year. When compounded over a period of ten-to-twenty years, these impacts could be significant; they range from about 8 to 36 Bcf of incremental gas consumption over baseline levels across all sectors. The sensitivity analysis indicates that gas consumption in 2020 is likely to be between 5 and 20 percent greater than in 2000, depending on future price and income levels. A summary of the various sensitivities has been presented in Table 10.2.

Table 10.2: Summary of Forecast Sensitivities

High Price Forecast Summary

2000	17,500,093	28,451,442	73,197,507	35,569,901	154,718,943
2005	19,035,431	29,336,492	74,978,844	34,521,334	157,872,101
2010	20,735,890	29,585,393	76,760,215	36,105,921	163,187,419
2015	22,620,716	30,107,039	78,541,636	37,927,136	169,196,528
2020	24,712,105	30,663,720	80,323,106	39,771,208	175,470,138
10 Year Increase	3,235,797	1,133,951	3,562,708	536,020	8,468,477
20 Year Increase	7,212,012	2,212,278	7,125,599	4,201,307	20,751,195

High Income Forecast Summary

2000	17,584,947	28,576,984	73,271,847	35,569,901	155,003,678
2005	19,631,736	30,629,414	75,426,724	38,947,146	164,635,020
2010	21,920,440	31,970,191	77,584,783	40,734,885	172,210,299
2015	24,479,334	33,536,403	79,746,048	42,789,590	180,551,375
2020	27,340,683	35,066,944	81,910,542	44,870,081	189,188,250
10 Year Increase	4,335,493	3,393,207	4,312,935	5,164,984	17,206,621
20 Year Increase	9,755,736	6,489,961	8,638,695	9,300,180	34,184,572

Low Price Forecast Summary

2000	17,536,585	28,683,799	73,280,303	35,569,901	155,070,588
2005	19,365,289	31,915,682	75,477,994	36,291,659	163,050,624
2010	21,396,261	34,555,030	77,679,715	37,957,507	171,588,512
2015	23,652,356	37,571,398	79,885,529	39,872,118	180,981,401
2020	26,159,711	40,685,286	82,095,472	41,810,757	190,751,225
10 Year Increase	3,859,676	5,871,231	4,399,411	2,387,606	16,517,924
20 Year Increase	8,623,126	12,001,487	8,815,169	6,240,856	35,680,637

Low Income Forecast Summary

2000	17,451,674	28,532,498	73,205,369	35,569,901	154,759,441
2005	18,781,361	30,387,626	75,025,986	31,865,847	156,060,819
2010	20,261,517	31,807,560	76,846,603	33,328,543	162,244,222
2015	21,910,548	33,225,744	78,667,220	35,009,664	168,813,176
2020	23,749,813	34,635,893	80,487,837	36,711,884	175,585,427
10 Year Increase	2,809,844	3,275,062	3,641,234	-2,241,358	7,484,781
20 Year Increase	6,298,140	6,103,395	7,282,468	1,141,983	20,825,986

10.3: Expanded Service Opportunities

Our analysis also examines the opportunities for expanded service in areas that currently do not have natural gas service. We examined statewide total usage opportunities by region, as well as new service opportunities in areas that are near (within 20 miles) the proposed AHR and existing LDC infrastructure.

After considering a range of expanded service opportunities throughout the state, the largest concentrations of new service opportunities appear to be in the Southcentral and Interior regions. There are also opportunities for increasing natural gas usage within the existing service territories for the Southcentral region LDCs (primarily Enstar). Increasing existing penetration levels by 10 percent results in almost as much expanded usage as moving into new service areas. However, existing average penetration rates of around 80 percent are already high and unlikely to increase under relative prices prevailing today.

A summary of these expanded opportunities is provided in Table 10.3. We have assumed that these service expansion opportunities will be phased in over time with full service opportunities being realized in 2020.[1] Table 10.3 also shows the potential gas demand-supply imbalance in the Cook Inlet Basin. While this does not reflect expanded service, per se, it illustrates the quantity of existing gas usage in Southcentral that may not be met from existing reserves in the Cook Inlet Basin (again, assuming relative energy prices in the future are consistent with levels observed today).

Table 10.3: Summary of Expanded Service Opportunities

2000	154,980,358	0	0	0	154,980,358
2005	160,395,253	556,182	0	1,078,526	162,029,961
2010	166,836,744	1,112,364	41,325,000	2,157,052	188,020,160
2015	174,587,941	1,668,546	111,161,000	3,235,578	220,817,065
2020	182,232,010	2,224,728	195,256,000	4,314,104	299,931,842

Original Source: Table 6.9

[1]The realization of these service opportunities are assumed to increase cumulatively by about 25 percent each year starting in 2005.

10.4: New Industries

There are opportunities for expanding natural gas usage by the addition of new industries. The two that were highlighted for investigation in this study included the addition of internet server farms and a major petrochemical industry. Both are energy-intensive industries. However, the addition of a typical facility for a large internet facility would have a small impact on total in-state usage. A major petrochemical facility, on the other hand, could have a more meaningful impact. A summary of these new industry opportunities has been presented in Table 10.4. We have assumed that the internet facility opportunities will be realized in full by 2005. The petrochemical opportunities are assumed to be realized after the operation of the proposed AHR gasline is completed and enter the forecast in 2010.

Two urea plant usage opportunities are presented. The first assumes a relatively constant utilization at the existing facility but at levels that are near previous historic peaks (about 7.2 Bcf above 2000 levels). The second provides the usage levels from a potential plant expansion discussed in Chapter 7.

Two estimates for LNG usage are also presented. The first estimate presents relatively constant levels of gas usage. The second estimate reflects the outer range of potential gas usage that was discussed in Chapter 7 (i.e., about 2.8 Bcf per year of additional gas consumption).

Table 10.4: Summary of New Industry Opportunities

Date	Baseline Total (Mcf)	Internet Server (Mcf)	Petrochemical Facility (Mcf)	Ammonia Urea Incremental (Mcf)	Ammonia Urea Expanded (Mcf)	Existing LNG (Mcf)	Incremental LNG (Mcf)	New Total (Mcf)
2000	154,980,358	0	0	7,224,195	0	78,533,532	0	240,738,084
2005	160,395,253	4,355,910	0	7,224,195	0	78,533,532	0	250,508,890
2010	166,836,744	4,355,910	27,853,333	7,224,195	15,000,000	78,533,532	2,873,468	302,677,181
2015	174,587,941	4,355,910	27,853,333	7,224,195	30,000,000	78,533,532	2,873,468	325,428,379
2020	182,232,010	4,355,910	27,853,333	7,224,195	30,000,000	78,533,532	2,873,468	333,072,448

Original Source: Table 7.1, 7.3

10.5: Fuel Switching

We examined all generating units in the state to identify facilities that could potentially shift their primary fuels to natural gas. Fuel oil and diesel facilities were the most attractive candidates. The highest concentration of these facilities were located in the Interior region of the state. There is approximately 200 MWs of capacity in this region that could shift from fuel oil to natural gas. Fuel switching opportunities would comprise a considerable source of new gas consumption. The reason for this is twofold. First, in total, the 200 MWs of capacity is of a relatively meaningful size. Second, many of these facilities are older, with heat rates that are greater (i.e., less efficient) than many new technologies. Hence, a greater amount of gas usage per every kWh generated. A summary of these fuel switching opportunities has been provided in Table 10.5. The table assumes that these fuel switching opportunities will not be realized until the proposed gasline is in operation.

Table 10.5: Summary of Fuel Switching Opportunities

Date	Baseline Total (Mcf)	New Gas Generation (Mcf)	New Total (Mcf)
2000	154,980,358	0	154,980,358
2005	160,395,253	0	160,395,253
2010	166,836,744	15,938,973	182,775,717
2015	174,587,941	15,938,973	190,526,914
2020	182,232,010	15,938,973	198,170,983

Original Source: Table 8.4 and Table 9.6

10.6: Gas by Wire

There is a considerable supply side efficiency opportunity for new central station gas fired generation. The economics of a 250 MW combined cycle facility stack up favorably with the dispatch costs of existing generating units. However, the state does not have a potential capacity need until the year 2014. If a new generating unit were to be added prior to that time, older generation could be displaced. The displacement of this older generation could result in stranded costs that would have to be recovered. The public ownership of these facilities raises important questions about potential cost recovery since the traditional separation between ratepayers and shareholders does not exist. Given the higher efficiency of a new power station, gas usage associated with this power generation facility would be considerable but less than fuel switching at existing power facilities discuss above.

A summary of the gas-by-wire gas usage has been presented in Table 10.6. In this table, natural gas usage from new power generation is not expected to increase until 2015, given that Alaska will probably not have need for a new generation facility until the prior year.

Table 10.6: Summary of Gas by Wire Application

Date	Baseline Total (Mcf)	New Gas Generation (Mcf)	New Total (Mcf)
2000	154,980,358	0	154,980,358
2005	160,395,253	0	160,395,253
2010	166,836,744	0	166,836,744
2015	174,587,941	12,483,000	187,070,941
2020	182,232,010	12,483,000	194,715,010

Original Source: Table 8.7

10.7: Supplying Gas to New Usage Opportunities

Supplying natural gas to concentrated opportunities for new in-state usage would require significant infrastructure investments. These investments include taps and meter stations to the main AHR gas pipeline, transportation capital costs for pipelines to the city gate, and capital costs to lay distribution mains and service connections.

We examined a number of major concentrations of potential gas usage, and modeled the typical costs of supplying natural gas to these potential applications. These results included:

New Service to the Interior: Positive opportunities for natural gas service from initial analysis. This option warrants further study. Estimated household energy savings of shifting from fuel oil to natural gas were about 20 percent, while savings associated with shifting from electricity to natural gas were approximately 24 percent.

Gas by Wire: There are competitive opportunities for new power generation. However, as noted earlier, the need for a major new power generation resource is questionable until the year 2014.

Expanded Service to the Southcentral: Study results indicate that, in order to be competitive, throughput on a lateral spur line connecting Southcentral must achieve volumes beyond levels that correspond to various individual and incremental gas usage applications considered in

this study. Some portion of gas usage -- 30-to-40 Bcf per year -- currently supplied by producing fields in the Cook Inlet Basin would be required to generate sufficient economies of scale. The decline rates of existing Cook Inlet fields, combined with the steady progression of demand in the Southcentral and Interior regions suggest that, even with the near-term discovery of one Tcf of additional Cook Inlet reserves, a supply shortfall of 30-to-40 Bcf or more per year is likely to occur sometime between 2009 and 2015. Thus, a lateral spur pipeline that delivers gas into the Southcentral region could provide a long-term, economic solution to the supply-demand imbalance projected for this area.

Fuel Switching: Small, but positive economic opportunities for switching fuel oil fired power plants to natural gas in the Interior region. Net fuel savings ranged between a third to a fifth of a cent per kWh generated.

10.8: Summary of Baseline Forecast, Potential New Usage Opportunities, and Total In-State Demand

Based upon our analysis, there are some 107 Bcf of new usage opportunities in Alaska by the year 2020. This represents about 41 percent of baseline forecast in-state use in 2020.[2] Figure 10.1 presents each of these opportunities relative to the baseline forecast, while Figure 10.2 presents a pie chart breaking out the relative contribution each application has to total new usage opportunities.

This estimate is based on the assumption that all of the new usage opportunities are developed: Southcentral residential usage; Interior retail usage; internet facility development, petrochemical facility development; fuel switching opportunities; high utilization LNG and urea plant use; urea plant expansions; and gas by wire application. As noted in Chapter 9, the economics of supplying natural gas to many of these opportunities on an individual basis will not be competitive. The best opportunities for attaining these new usage levels may be from bundling a number of applications.

[2]Baseline includes existing LNG usage. New usage opportunities represent 58 percent of non-LNG baseline (i.e., residential, commercial, industrial, and electric utility).

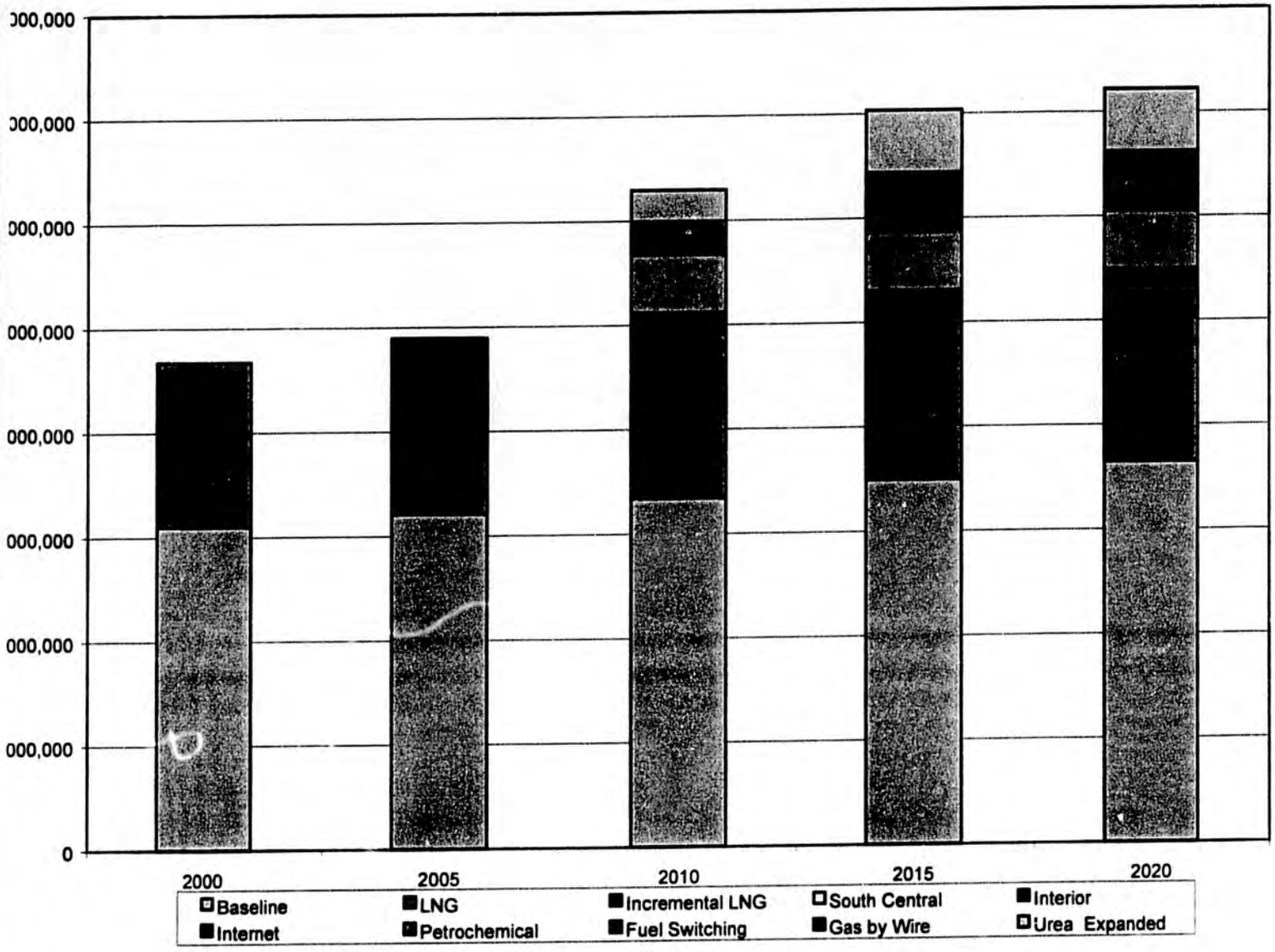

Figure 10.1: Summary of Baseline Forecast and New Usage Opportunities

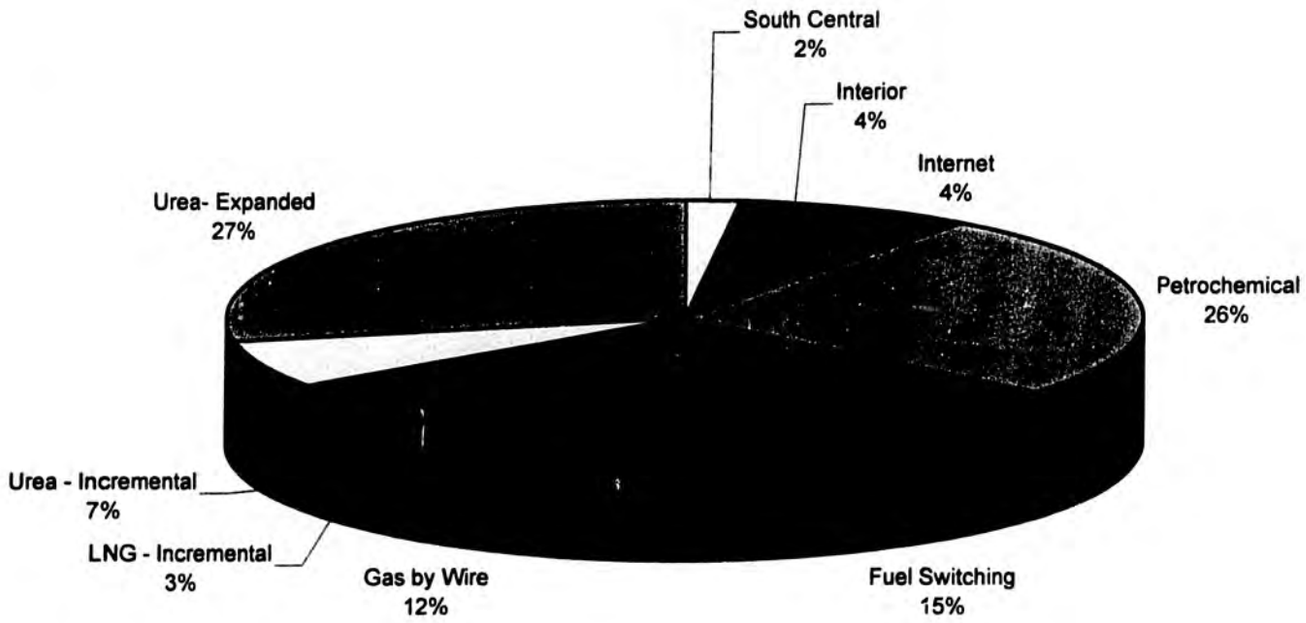

Figure 10.2: Percent Contributions, by Application, for New Usage Opportunities by 2020

As noted in Chapter 9, one of the largest potential concentrations of usage for ANS gas could be in the Southcentral region of the state. Realizing these usage levels, however, will be a function of future natural gas resource additions in the region. If these fail to materialize, then a substantial portion of Southcentral usage could be met with gas supplies from the North Slope. In order for these supplies to come close to being economical, volumes of some 30 to 40 Bcf will have to be served from outside the region. Figure 10.3 shows how potential Southcentral usage, resulting from a regional supply short-fall, would compare to all the other new applications discussed in this report.

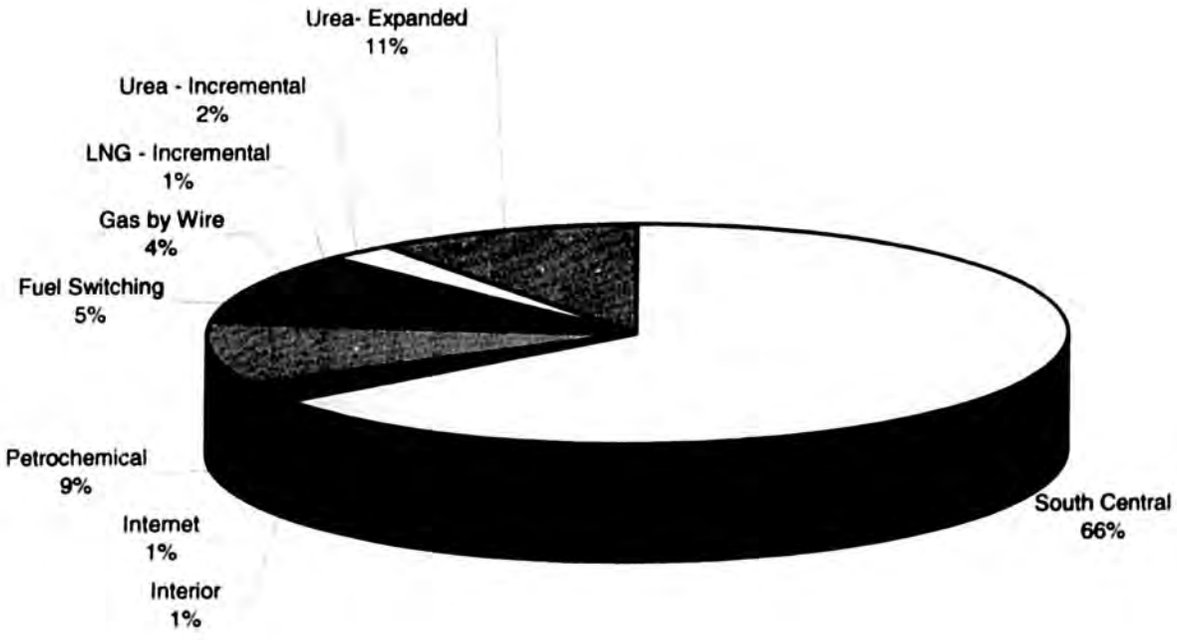

Figure 10.3: Southcentral Usage Relative to New Service Opportunities in 2020

SCOMM

129:7

STATE OF ALASKA

GAS PIPELINE OFFICE

TONY KNOWLES, GOVERNOR

550 W. 7th Avenue, Suite 1500
Anchorage, AK 99501
PHONE: (907) 276-0404
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MEMORANDUM

TO: Commissioner Pat Pourchot, Chairman
Gas Pipelines Cabinet

Senator Gene Therriault, Chairman
Legislative Budget and Audit Committee

Terry Klatt, Foothills Pipe Lines Alaska Inc.

Gary Gustafson, Alaska Gas Producers Pipeline Team

FROM: William G. Britt, Jr.
Gas Pipeline Coordinator

DATE: January 8, 2002

SUBJECT: Gas Pipeline Office Status Report
December 2001

Summary

Major activities during the month of December included:

- Work regarding a right-of-way (ROW) lease process for a natural gas pipeline project
- Work planning related to Foothills' ROW lease application;
- Permitting for the Alaska Gas Producers Pipeline Team (AGPPT) trenching tests;
- Budgeting for the second half of fiscal year (FY) 2002 and discussions with AGPPT and Foothills regarding modifications of the reimbursement memoranda of understanding (MOUs) for that period;
- Preparations for moving to new office space; and
- Recruiting.

A description of actions and status in each area follows.

Right-of-Way Lease Process

A concentrated effort was made during December to identify benefits and challenges associated with processing a State ROW application based on Notices to Proceed (NTP). I have concluded that an NTP-based lease may be necessary for the gas line due to the scope of the project. In late December I outlined a prospective NTP process to Commissioner Pourchot. Several procedural, substantive and policy issues will require resolution to successfully implement the process. Commissioner Pourchot gave me his approval to continue working those issues.

Foothills Work Planning

During December my staff continued to work with Foothills to complete several tasks related to their lease application, including draft plan reviews, permitting strategy development, and scientific data collection. Foothills submitted a draft schedule for submittal reviews and approvals associated with their lease application. My staff is currently reviewing the draft schedule.

A focused review of a subset of Foothills' application submittals is currently underway. For example, the Department of Fish and Game (DFG) has completed reviews of draft plans for protection of subsistence resources, material exploration and extraction, and river training structures; the Department of Public Safety has reviewed a draft plan for blasting operations, the Department of Environmental Conservation has completed a review of a draft air quality plan, and the Department of Natural Resources (DNR) has completed a review of a draft plan for protection of cultural resources. DNR is also completing a land title search and report.

AGPPT Trenching Trials

Processing of AGPPT's permit applications for trenching trials near Deadhorse and Fairbanks continued during December. The comment deadline for the Division of Governmental Coordination's (DGC's) public notice on the proposed trenching trials was December 31. The only comments that were received were from regulatory agencies; no comments were received by the comment deadline from members of the public. Discussions with AGPPT regarding responses to comments are ongoing. We plan to distribute a proposed consistency determination, incorporating agency comments, January 9, 2002. We plan to issue a final consistency determination by January 15, 2002.

Budgeting

In late November I met with AGPPT and spoke with Foothills and Legislative Budget and Audit Committee members regarding budgeting for the second half of FY 2002.

Foothills reiterated their desire to move forward rapidly in the processing of their State ROW application and presented their preliminary funding ceiling for the remainder of calendar year 2002. In mid-December I submitted a draft MOU addendum, which reflected the proposed budget and scope of work for second half of FY 2002, to Foothills and the Department of Law for their review.

The Legislative Budget and Audit Committee agreed to my requested level of funding for the state's share of expenses, to fulfill tasks specified in MOUs and cover non-reimbursable costs for the second half of FY 2002.

AGPPT indicated that the only work remaining was the trenching trials, and the AGPPT representative drafted an MOU addendum for January through June that reflected costs associated with permitting and oversight associated with the trials and a portion of the GPO indirect costs. The cost estimate and subsequent discussions with AGPPT representatives indicate that AFPPT is willing to fund only a small portion of the GPO total indirect costs.

As of the end of December, a final GPO budget for the second half of FY 2002 has not been determined, pending feedback from AGPPT regarding their commitment to fund necessary functioning of the GPO in accordance with their MOU and Administrative Order 187.

Office Space

Tenant improvements and build-out for the selected office space in the Key Bank Plaza building continued during December. We anticipate moving to the new space by mid-January 2002.

Recruiting

No additional GPO personnel were hired during December 2001. The GPO currently consists of 14 staff from 4 designated State agencies and two federal agencies:

- DNR staff consists of my position, my deputy, the Administrative Manager, the Administrative Assistant, an Administrative clerk, a Records Analyst [shared with the Joint Pipeline Office (JPO)], and a Computer System Administrator (shared with JPO)
- DFG staff consists of a liaison, a Design and Permitting Coordinator, and a Field Inspection and Compliance Coordinator
- Liaisons from DEC, DGC, Bureau of Land Management (BLM), and Minerals Management Service (MMS) have been assigned to the GPO

In addition, the Department of Law has assigned two Assistant Attorneys General (AGs) to assist us.

Recruitment is ongoing for a Chief Engineer, a Right-of-Way Chief and a Public Information Officer. The 3 remaining designated agencies – DLWD, DTPF, and DPS - are also recruiting for liaisons. Recruiting continues to be difficult due to the low compensation and extraordinarily high risk associated with the positions. Final decisions regarding the hiring of these positions are on hold, pending the outcome of a final FY 2002 (second half) budget for GPO.

Other Activities

GPO staff met with one of our assigned assistant AGs to discuss confidentiality authorities and applicability for historical and contemporary documents submitted by ROW lease applicants. The AG's office is currently preparing guidelines for handling documents submitted with confidentiality disclaimers.

GPO staff met with the JPO's technical consultant regarding establishing an electronic document logging and recordkeeping system for new and existing documents.

DFG staff is taking the lead in working with our computer system administrators and interested and affected staff on system requirements and approaches to databases and GIS for the GPO. In mid-December DFG and DGC personnel from GPO attended a GIS demonstration presented by Foothill's local consultant, Michael Baker Jr., Inc.

In early December the Deputy Pipeline Coordinator attended a Natural Gas Transportation and Marketing conference presented by the Rocky Mountain Mineral Law Foundation. Other attendees from Alaska included representatives from the Dept. of Law, DNR, Phillips Alaska, Inc. and local private law firms.

A large project to organize and index historical gas pipeline documents on file at the JPO continued during December and an updated index was completed at the end of December.

Work continues in the 6 divisions of DNR supporting the GPO: Mining, Land, and Water for land title work; Support Services/Land Records Information for land status work; Parks and Outdoor Recreation/Office of

History and Archeology for permitting assistance; Geological and Geophysical Surveys for research; SPCO for administrative support; and Oil and Gas for technical assistance.

Looking Forward

I plan to travel to Calgary and Ottawa in January or February, budget allowing, to continue our Canadian outreach efforts.

During the next several months, GPO staff will begin working with local governments, Native corporations, tribal councils and other aboriginal or First Nations organizations, the Alaska Mental Health Trust, the Alaska Railroad Corporation, the University, and other landowners and stakeholders with direct approval authorities.

The GPO intends to initiate a more aggressive outreach program during early 2002. In addition to the speeches, testimony, and interviews we now provide, we plan to distribute a newsletter, create and maintain a web site, and hold public meetings.

Cc: Michele Brown, Commissioner of Environmental Conservation
Frank Rue, Commissioner of Fish and Game
Wilson Condon, Commissioner of Revenue
Joseph Perkins, Commissioner of Transportation and Public Facilities
Ed Flanagan, Commissioner of Labor and Workforce Development
Deborah Sedwick, Commissioner of Community and Economic Development
Patrick Galvin, Director, Division of Governmental Coordination
Connie Nesgoda, Office of Management and Budget
John Katz, Director, of State/Federal Relations, Office of the Governor
Bruce Botelho, Attorney General
Heather Brakes, Senator Therriault's Office
Nico Bus, DNR
Colleen Burgh, GPO
Robin Pierce, GPO
Susan Anderson, JPO
Nancy Welch, MLW
Richard McMahon, LRIS
Judy Bittner, OHA
Milt Wiltse, DGGS
Jeff Mach, DEC
Jonne Siemons, DFG
Nina Brudie, DGC
Larry Ostrovsky, Law
Martin Schultz, Law
Kelly Nicolello, DPS/DFP
Colleen McCarthy, BLM
Dennis Hinnah, MMS

Alaska Reserves and Production

- **36% of total U.S. oil reserves.**
- 8.0 billion barrels of oil
- **17% of total U.S. gas reserves**
- 35 trillion cubic feet of gas
- **20% of total U.S. oil production**
- 1.04 million barrels of oil per day

Sources: Alaska data are from Department of Natural Resources, Division of Oil and Gas, 2001 Annual Report
U.S. data are from U.S. Crude Oil, Natural Gas, and NGL Reserves, 2000 Annual Report, U.S.D.O.E.-E.I.A.

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The State Revenue Pie

Petroleum Revenue Sources, (FY 2001)

Total Royalties, Bonuses, Rents & Settlements:

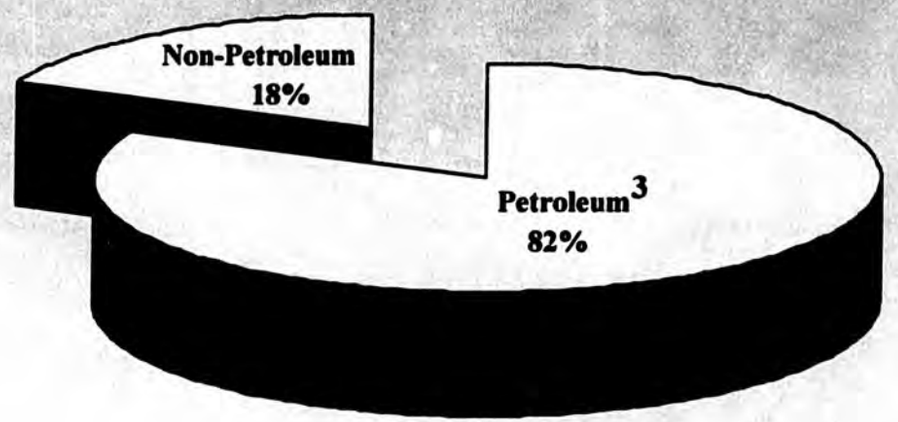
$1,145.9 Million

General Fund Royalties, Bonuses & Rents[1,2]:
$798.8 Million

Royalties to Permanent Fund & School Fund[4]:
$337.1 Million

Settlements to CBRF[4]:
$10.0 Million
(Includes Royalties & Taxes)

FY 2001 Unrestricted Revenue



Taxes:
$1,125.4 Million[2]

(Oil & Gas Property Tax + Tax Settlements + Income Tax + Severance Tax)

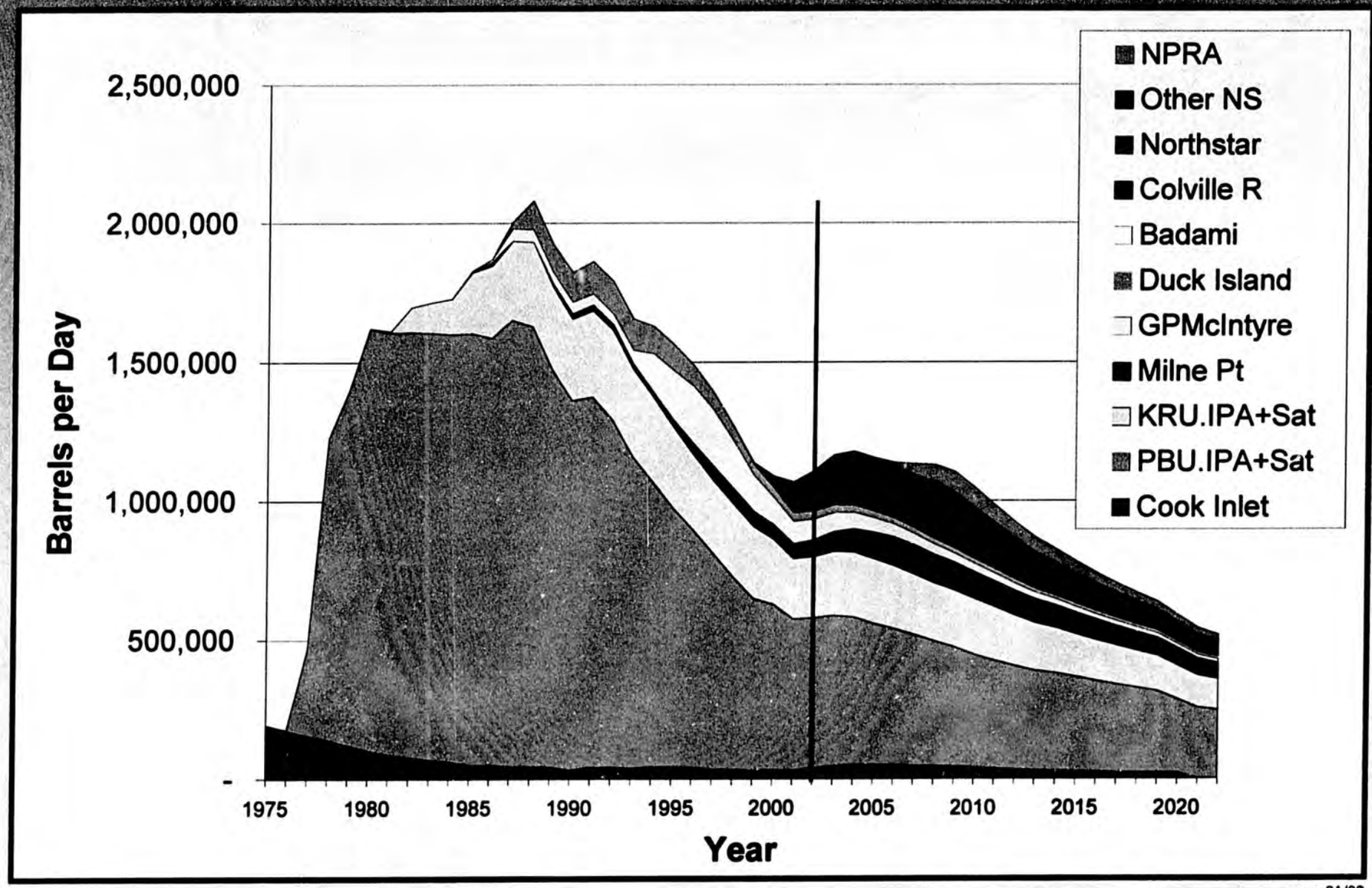
1 Includes Federally shared rentals

2 Source: pg. 23, DOR Fall 2001 Revenue Sources Book

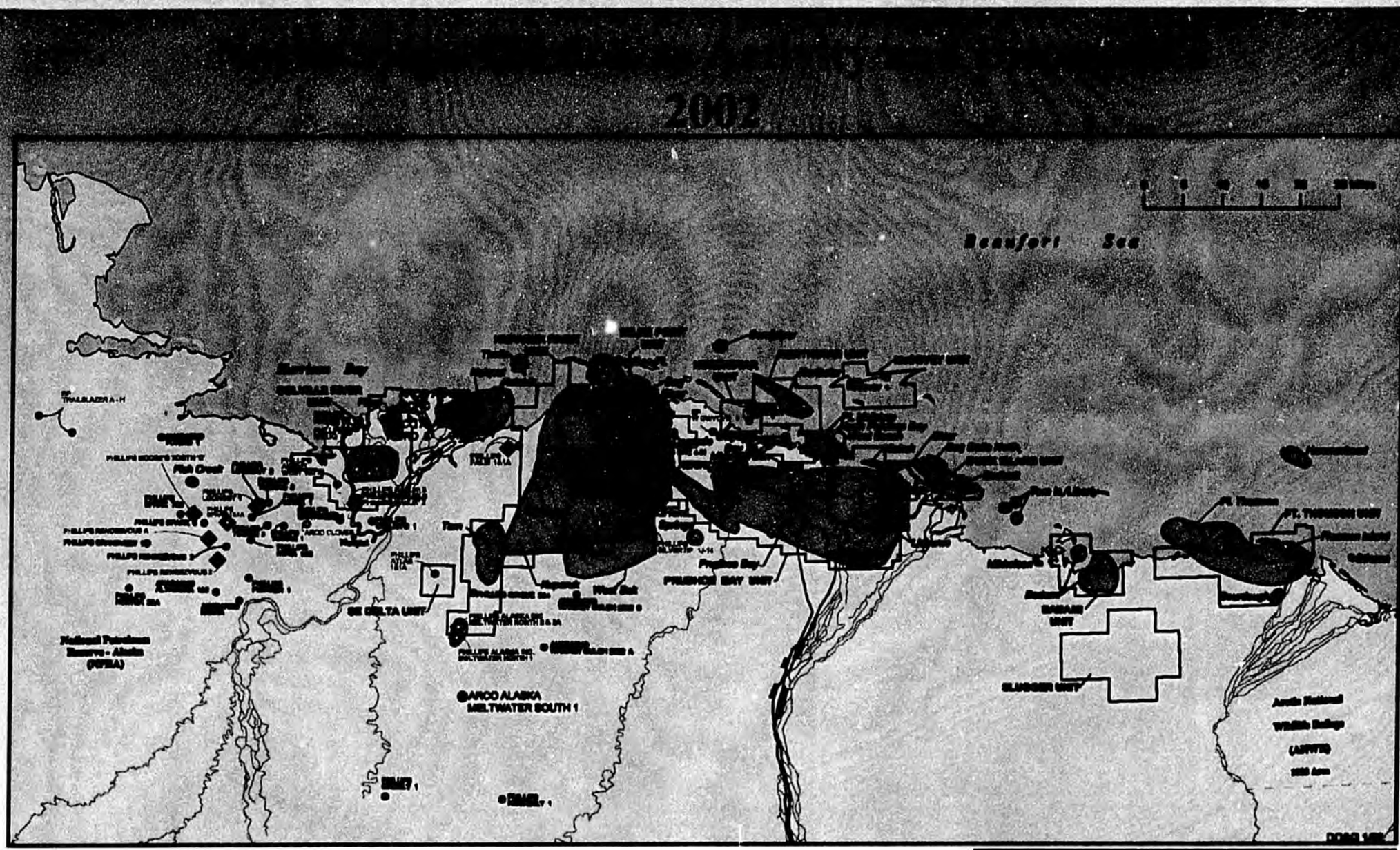
3 Source: pg. 22, DOR Fall 2001 Revenue Sources Book

4 Source: pg. 19, DOR Fall 2001 Revenue Sources Book

mdm 01/02

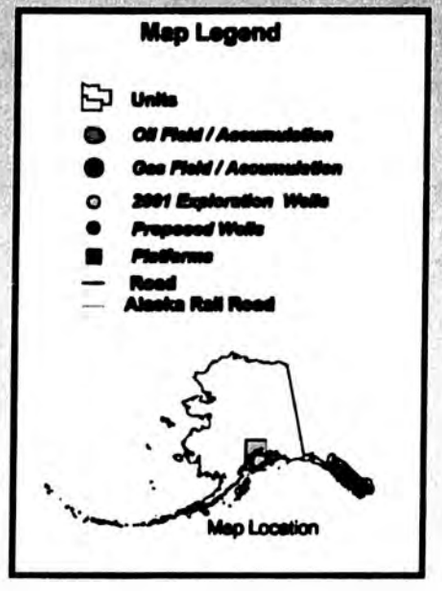

NPRA
Other NS
Northstar
Colville R
Badami
Duck Island
GPMcIntyre
Milne Pt
KRU.IPA+Sat
PBU.IPA+Sat
Cook Inlet
2,500,000
2,000,000
1,500,000
1,000,000
500,000
-
Barrels per Day
1975
1980
1985
1990
1995
2000
2005
2010
2015
2020
Year

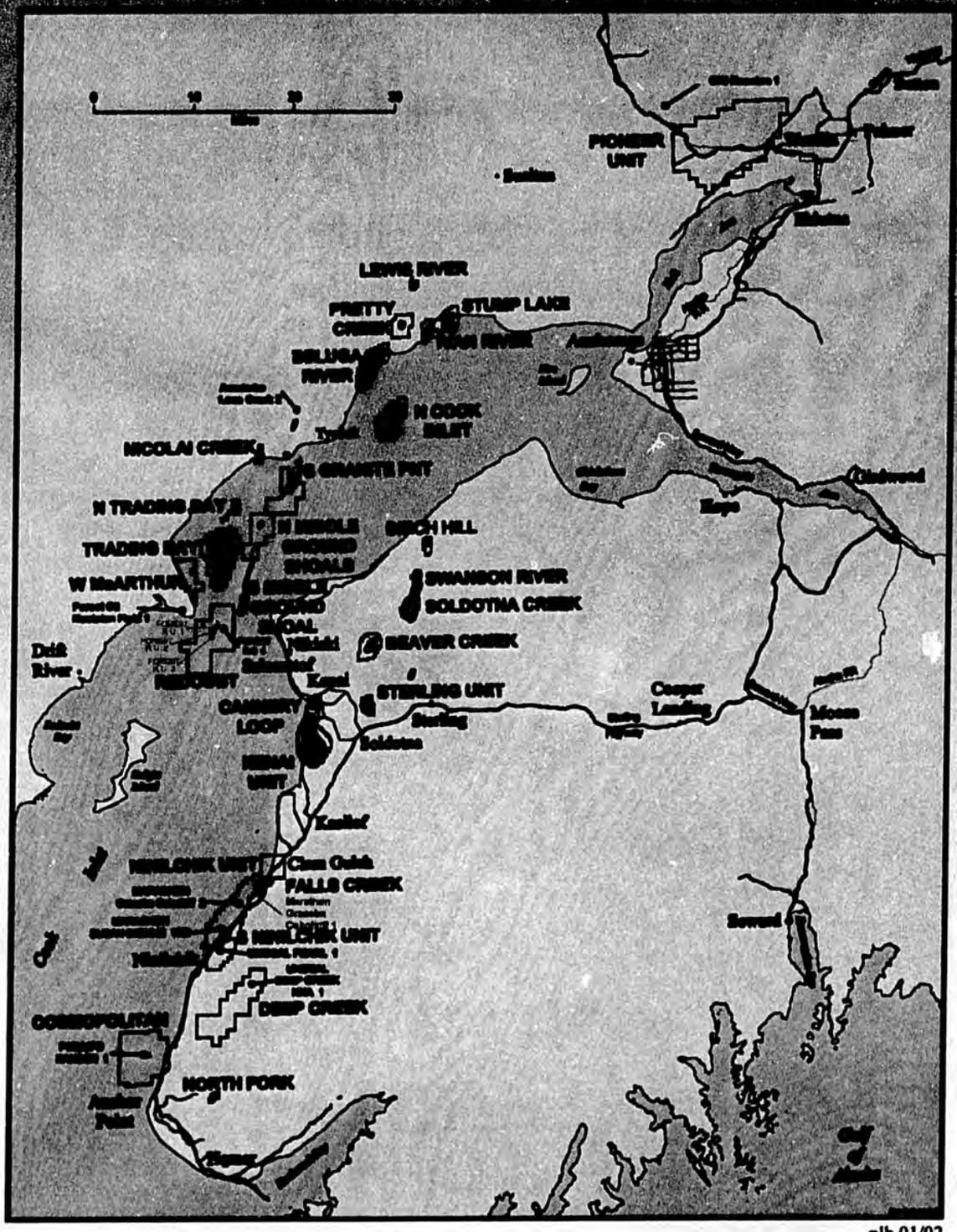
wen 01/02


2002
Beaufort Sea
PRUDHOE BAY UNIT
KUPARUK RIVER UNIT
ARCO ALASKA
MELTWATER SOUTH 1
National Petroleum Reserve - Alaska (NPRA)
Arctic National Wildlife Refuge (ANWR)
Map Legend
Units
Oil Field / Accumulation
2000 Exploration Wells
2001 Exploration Wells
2002 Proposed Wells
Active Wells
Recent Discoveries
Road
Trans-Alaska Pipeline

plb 01/02

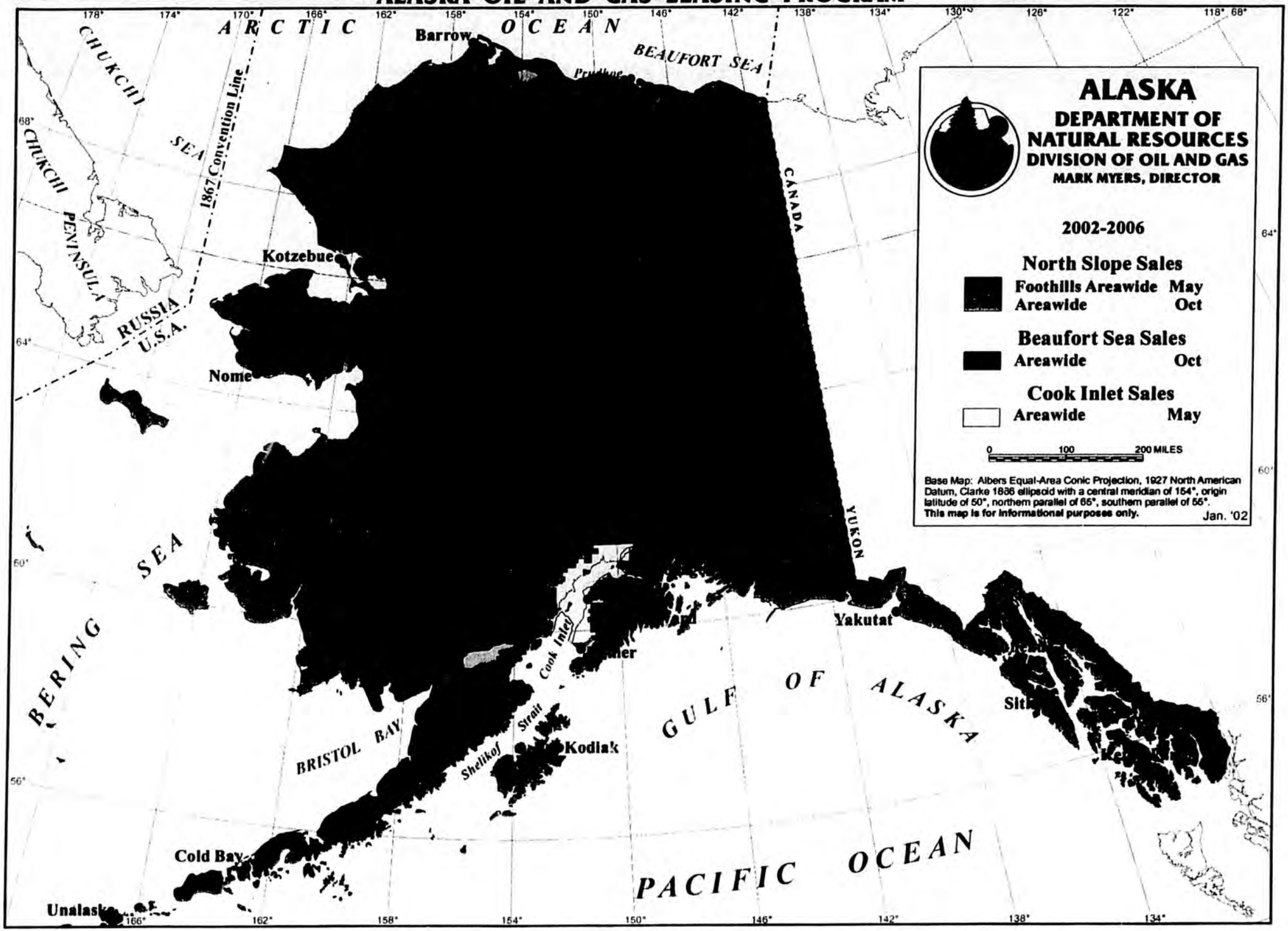
Cook Inlet
Oil & Gas Activity
January 2002





plb 01/02

ALASKA OIL AND GAS LEASING PROGRAM



ALASKA

DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
MARK MYERS, DIRECTOR

2002-2006

North Slope Sales
- Foothills Areawide May
- Areawide Oct

Beaufort Sea Sales
- Areawide Oct

Cook Inlet Sales
- Areawide May

0 100 200 MILES

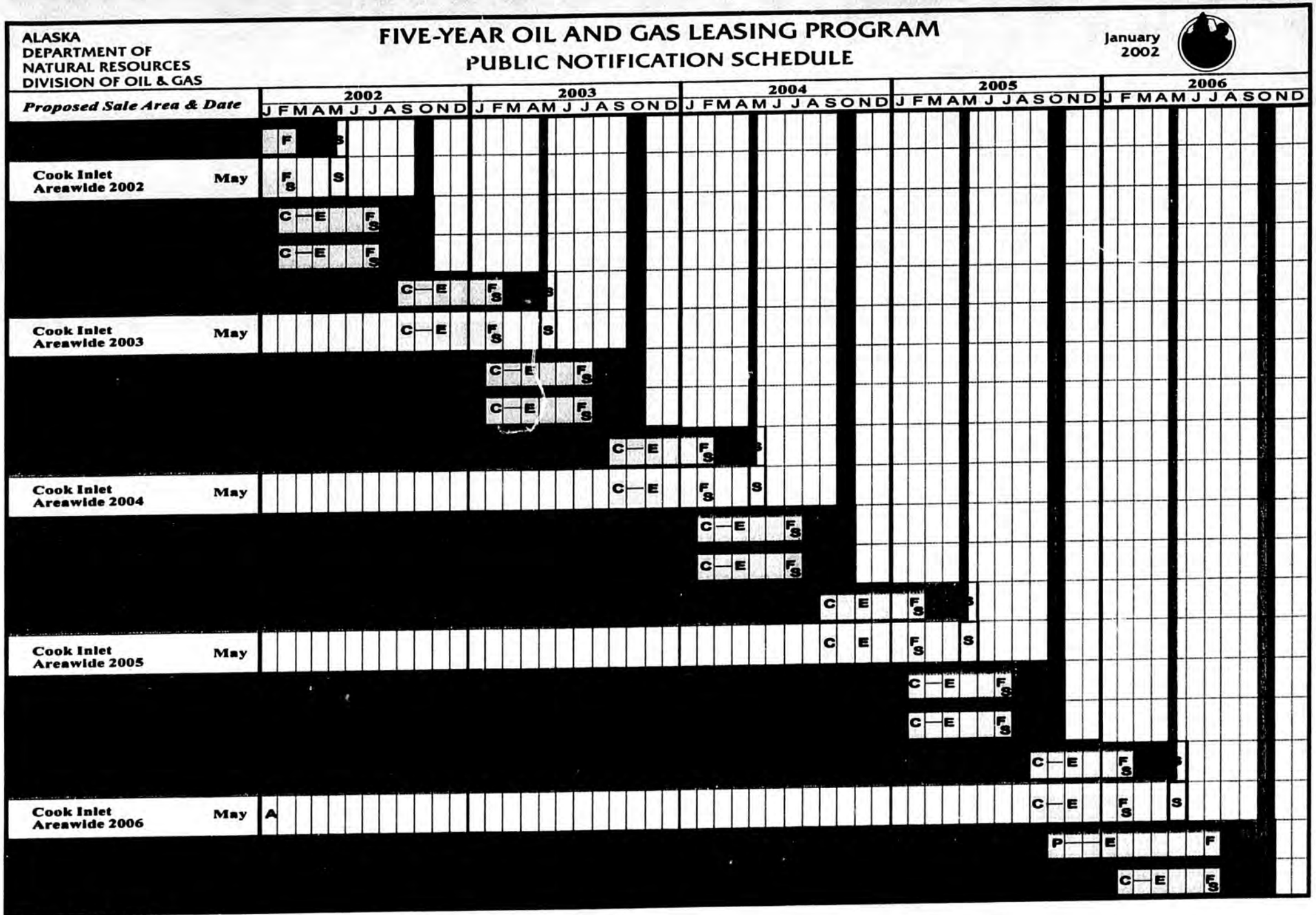
Base Map: Albers Equal-Area Conic Projection, 1927 North American Datum, Clarke 1886 ellipsoid with a central meridian of 154°, origin latitude of 50°, northern parallel of 65°, southern parallel of 55°.
This map is for informational purposes only.

Jan. '02

ALASKA
DEPARTMENT OF
NATURAL RESOURCES
DIVISION OF OIL & GAS

FIVE-YEAR OIL AND GAS LEASING PROGRAM
PUBLIC NOTIFICATION SCHEDULE

January
2002



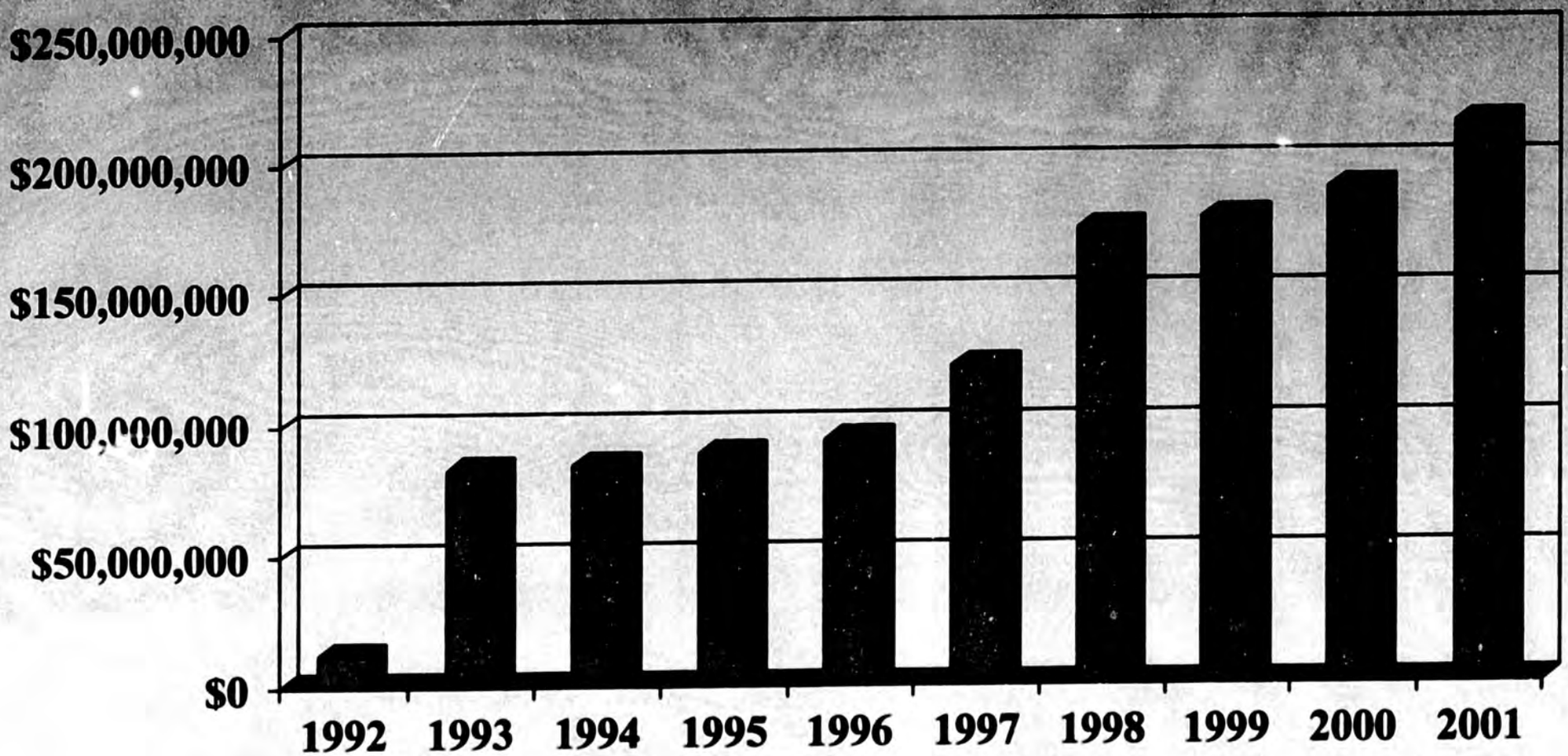
A = Sale Added to Schedule.
C = Call for Comments:
Request for New Information Made Available Since Last Finding.
E = End of Comment Period.
P = Preliminary Best Interest Finding / ACMP Consistency Analysis.

F = Final Finding and Notice of Sale and Terms.
FS = Supplement to Final Finding and/or Notice of Sale and Terms.
S = Sale.

Public Process

Visit our Website at "www.dog.dnr.state.ak.us/oil"

Cumulative Bonus Bids



jjh 11/01

2001 Areawide Lease Sales

Total Acres Leased = 1.6 Million

Total Bonus Bids = $24.5 Million

North Slope Foothills

- Area's First Lease Sale
- Largest State Sale Ever
- 8 Bidding Groups
- 978,560 Acres Leased
- $10.7 Million in Bonus Bids

North Slope

- 16 Bidding Groups (Shell returns after 13 yrs)
- 469,760 Acres Leased
- $7.4 Million in Bonus Bids

Cook Inlet*

- 6 Bidding Groups
- 102,523 Acres Leased
- $928,085 in Bonus Bids

(* Final Results)

Beaufort Sea

- 7 Bidding Groups
- 60,800 Acres Leased
- $5.4 Million in Bonus Bids

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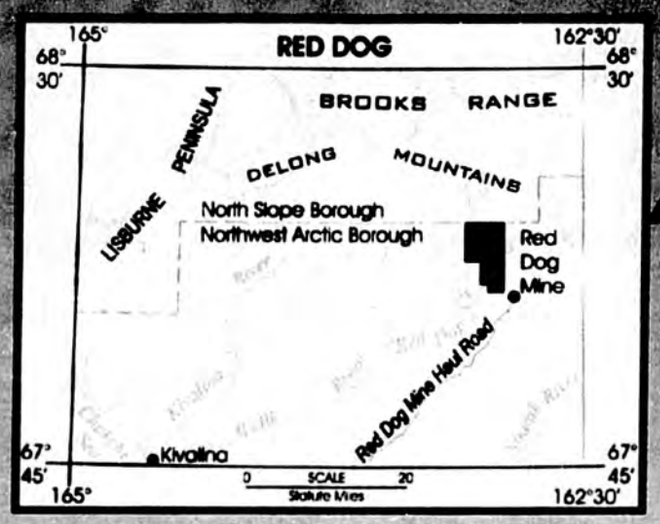
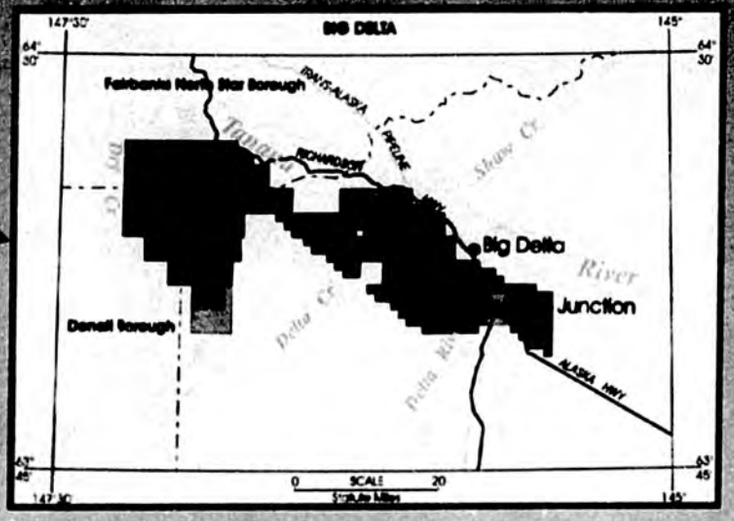
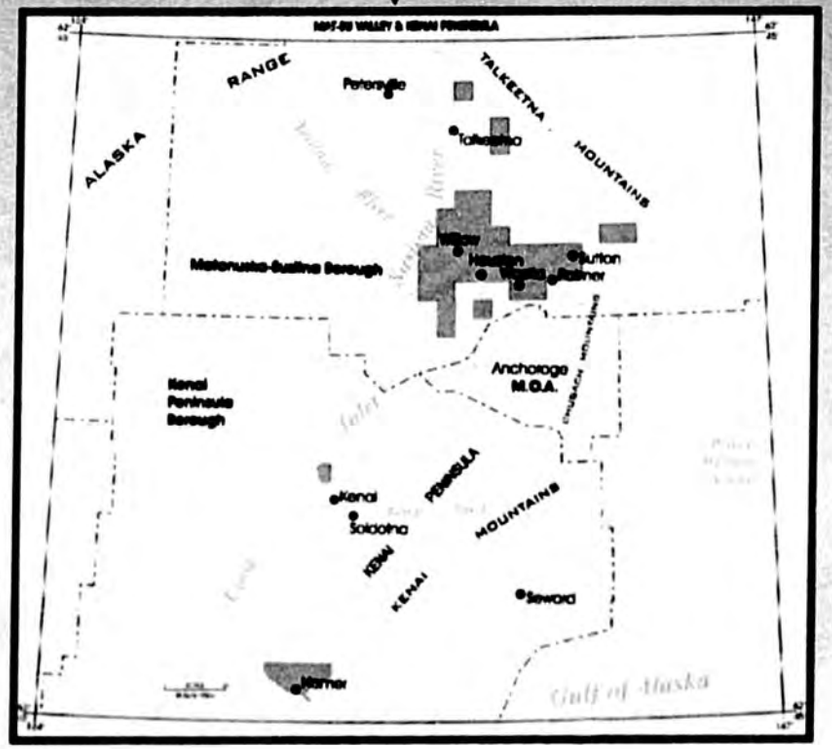






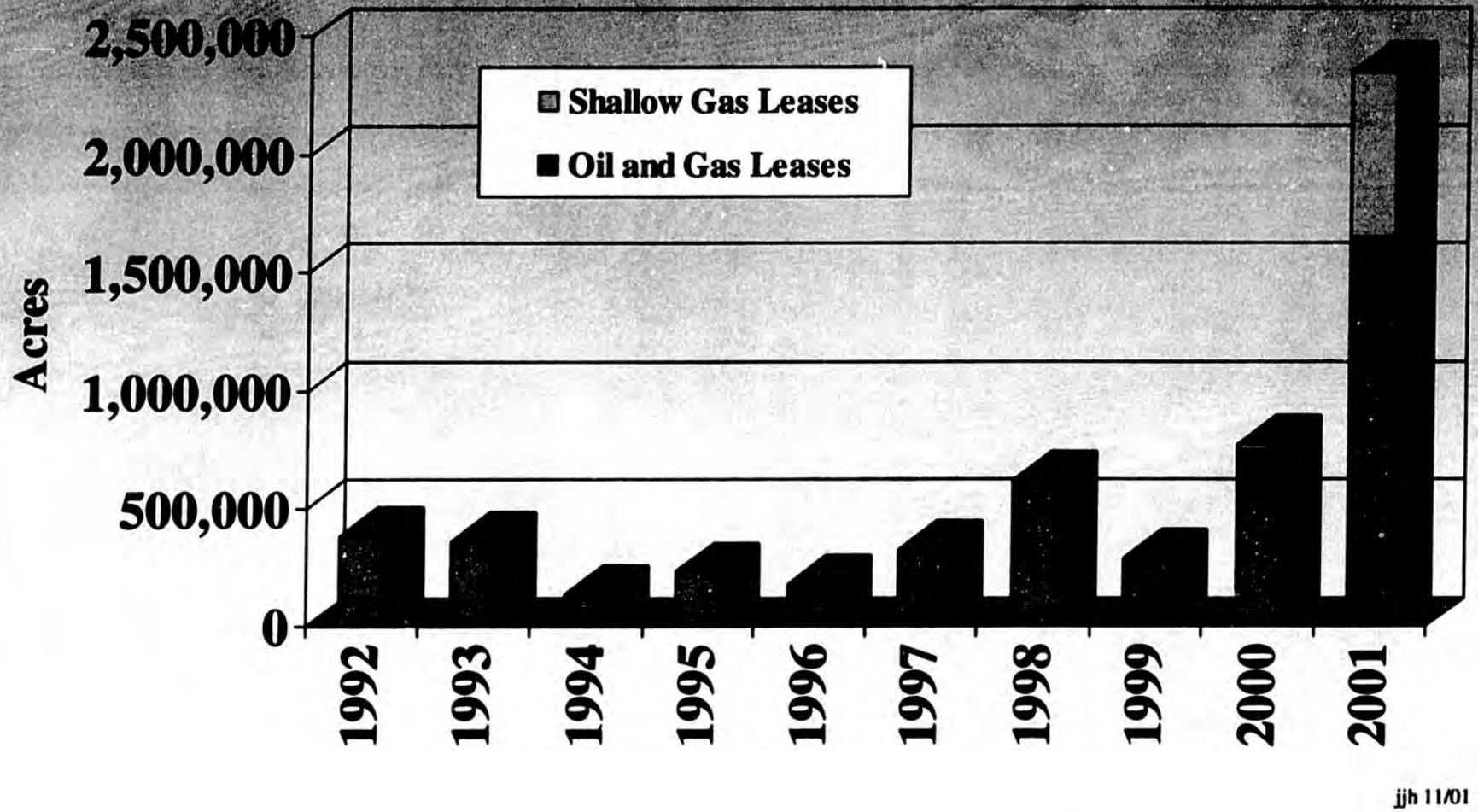


Issued Leases

Applications

ods 01/02

Acreage Leased



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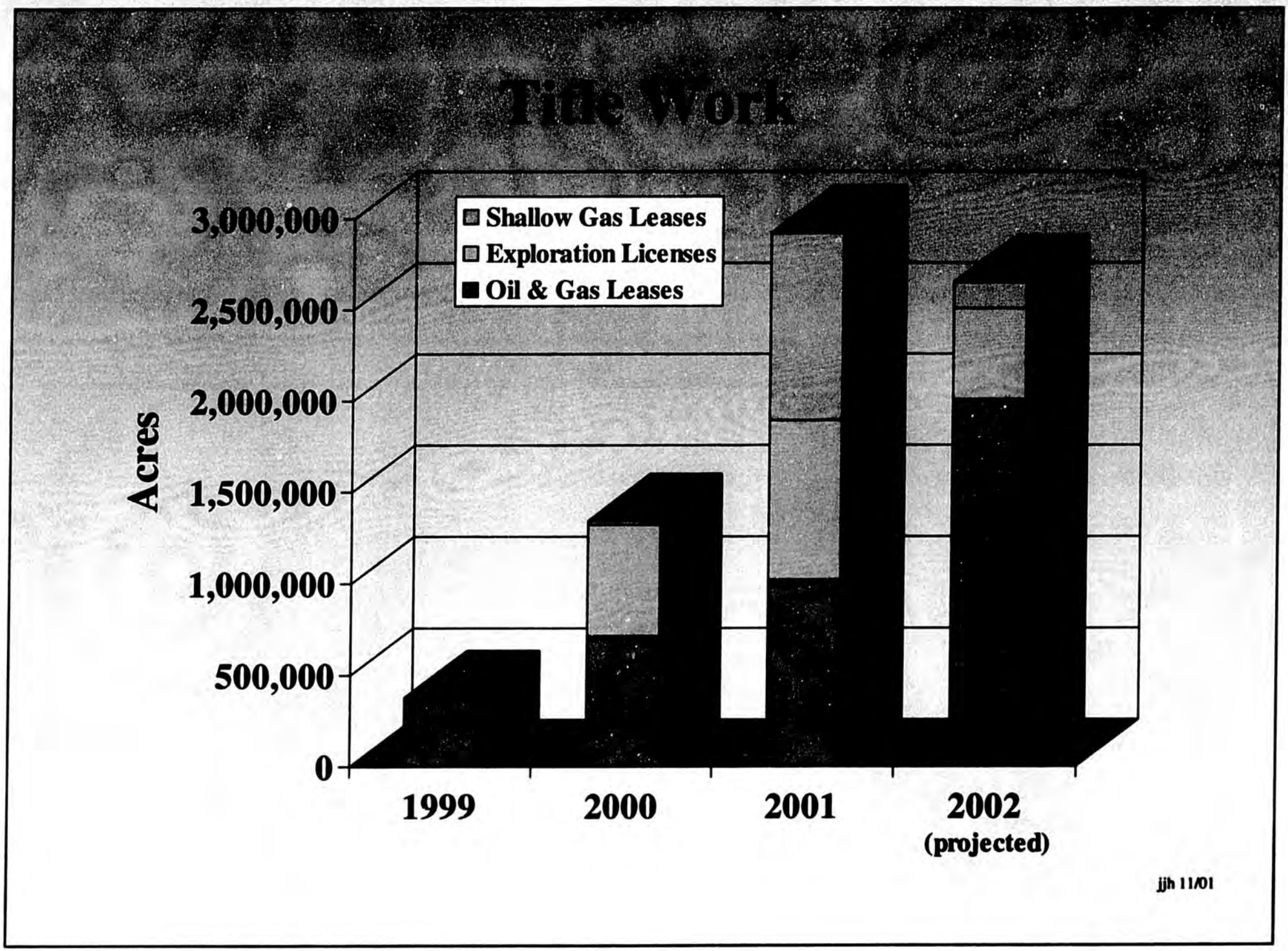
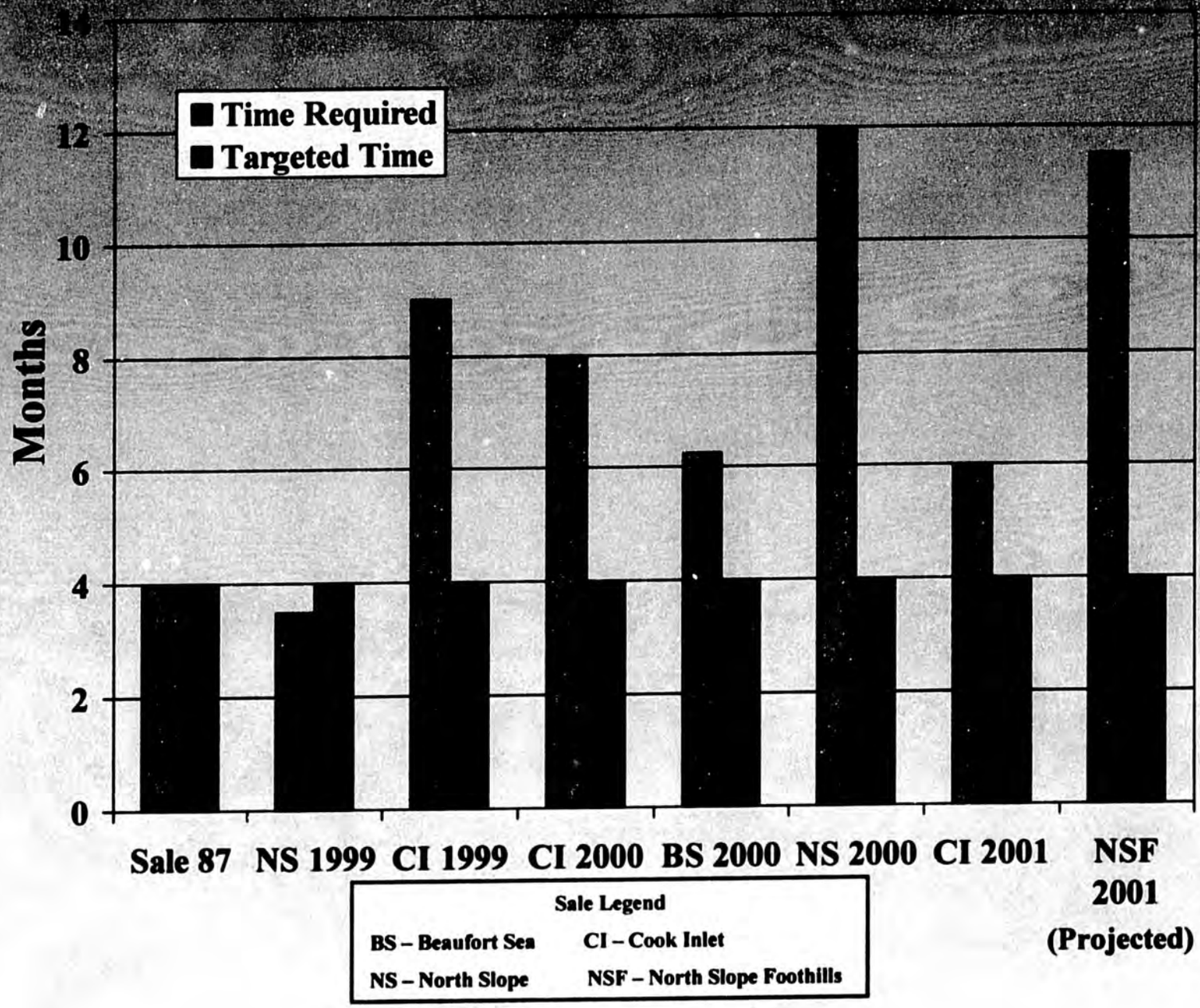

Title Work
Shallow Gas Leases
Exploration Licenses
Oil & Gas Leases
Acres
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
1999
2000
2001
2002
(projected)
jjh 11/01

Time Required to Sale



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Delays in Title = Delays in Sale

- It Takes up to 1 Year to Issue Leases
- FY 01 Revenue Delayed to FY 02

  Balance on Bonus Bids = $8.9 Million

  1st Yr Lease Rentals = $1.3 Million

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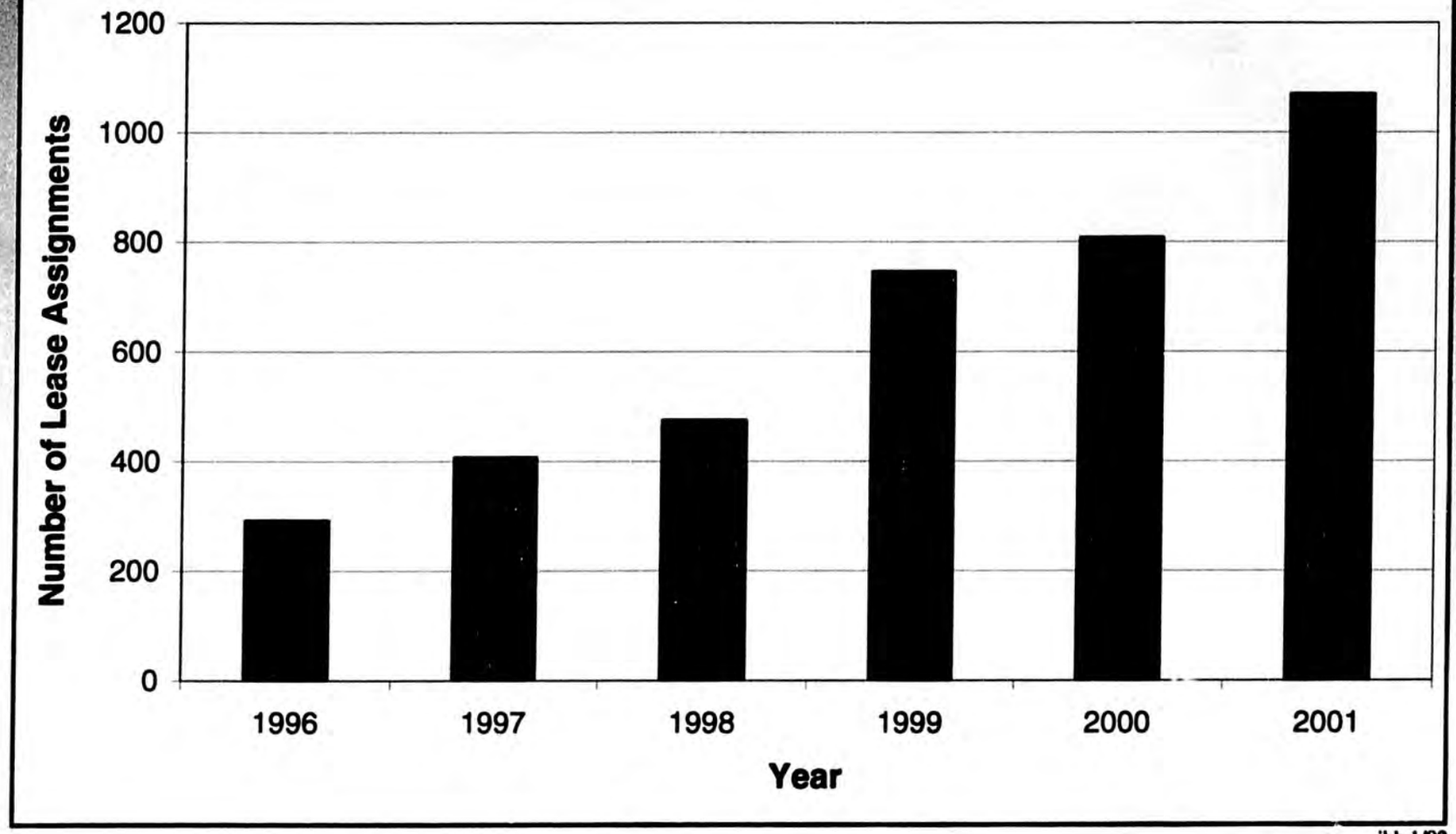
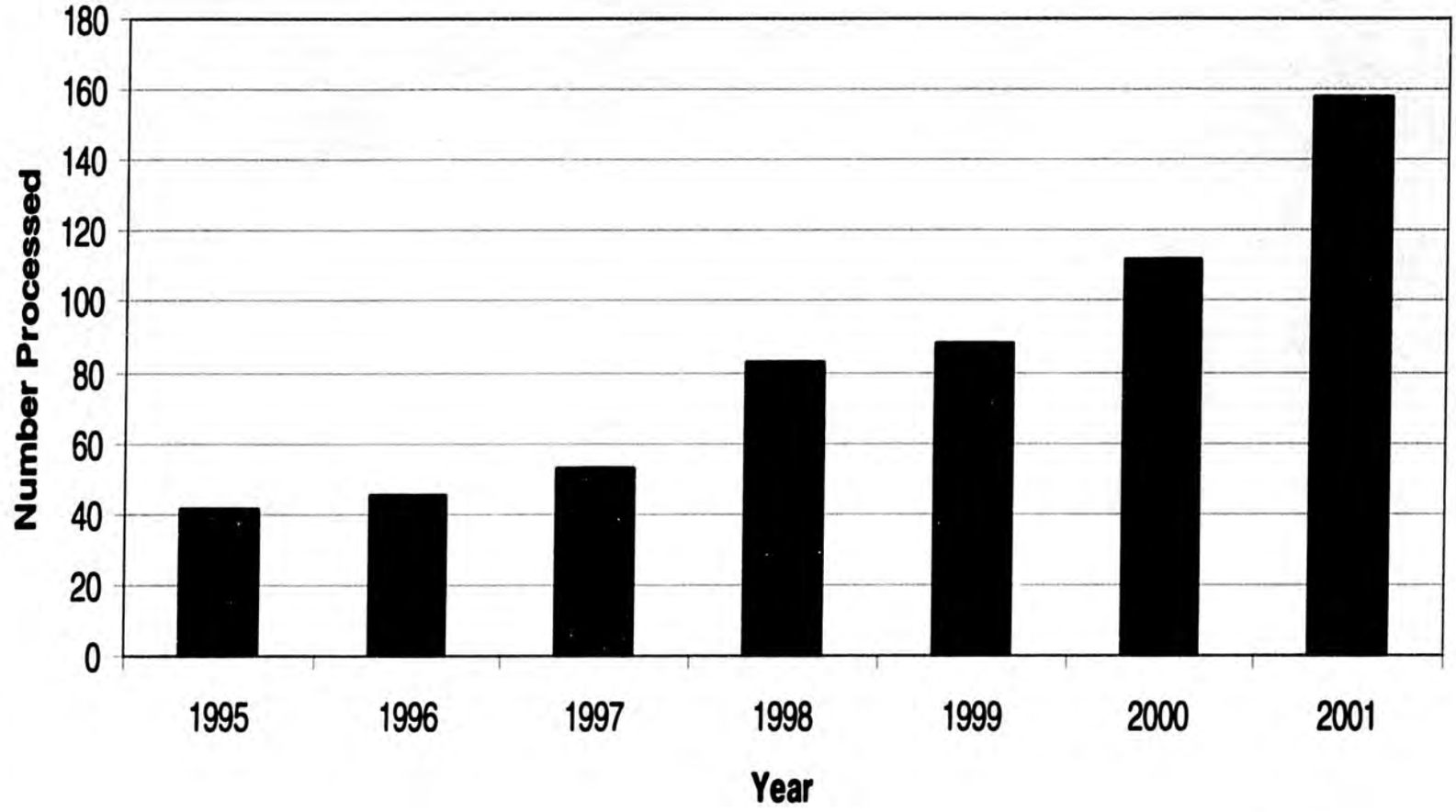
Lease Assignments in Alaska



jbh 1/02

Unit Actions



cdl 01/02

Actions include Units and Participating Areas formed, expanded, contracted, and terminated; Unit decisions appealed; Unit Plans of Exploration and Development reviewed and approved.

PBU Mechanisms

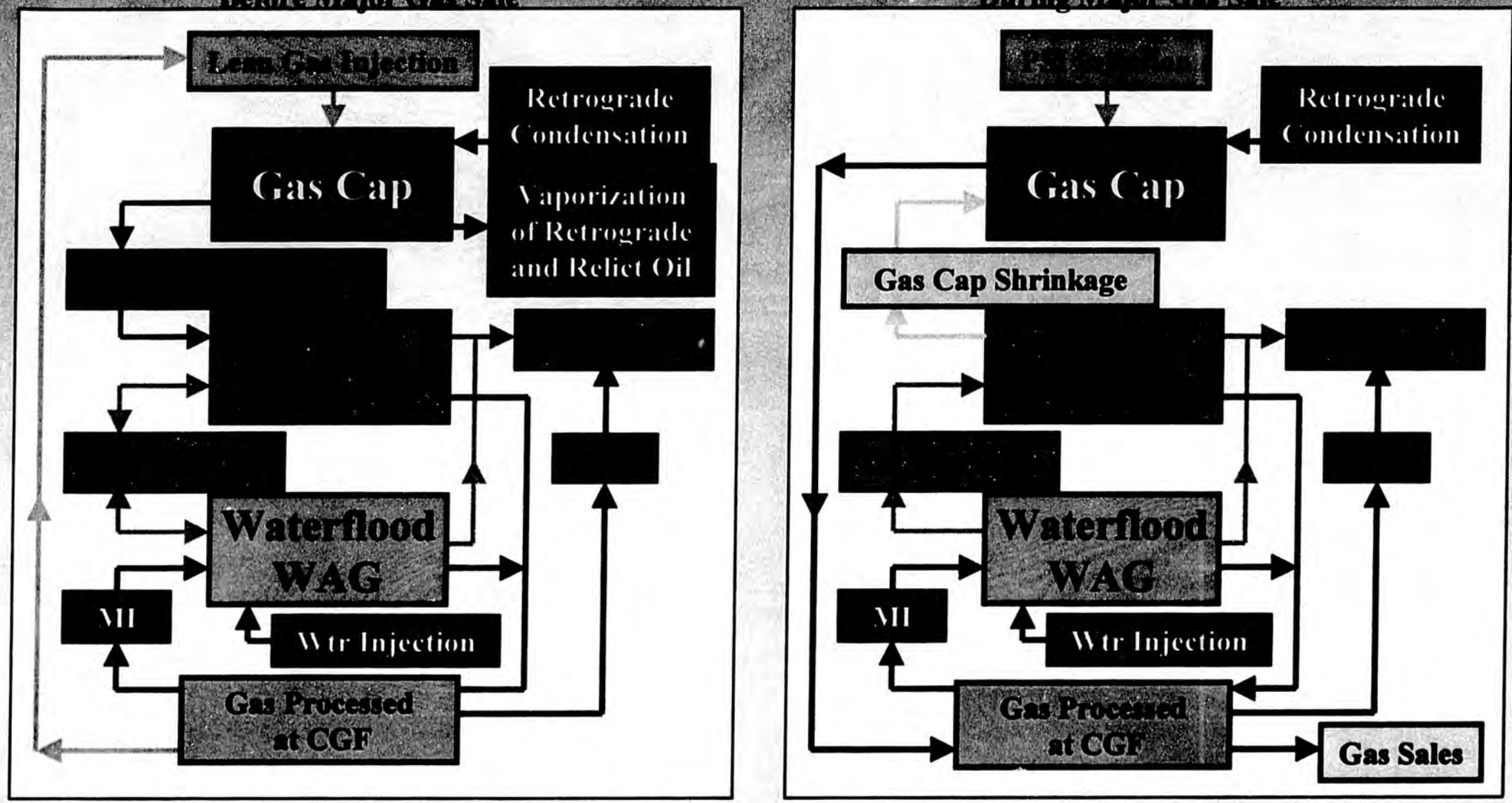
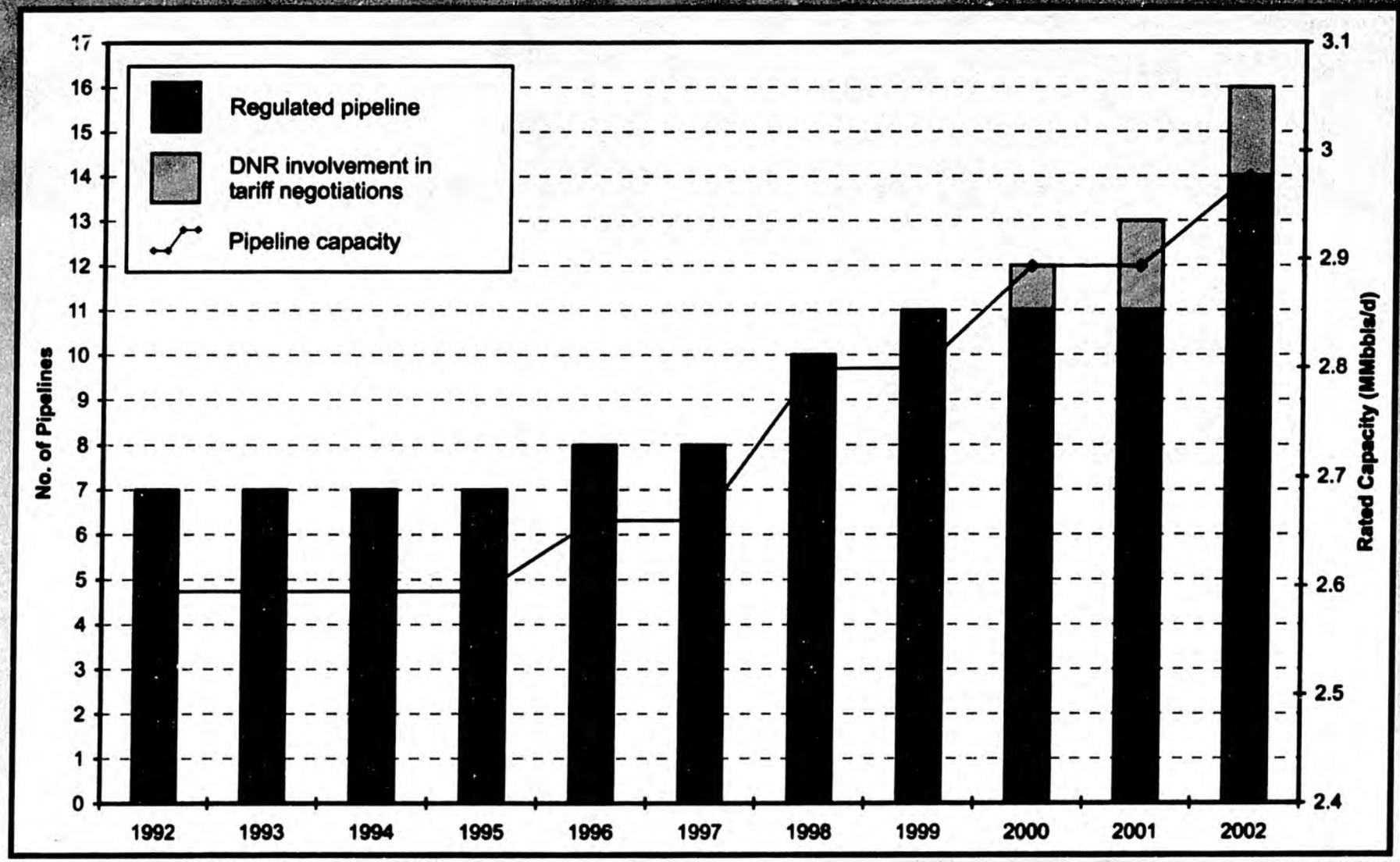


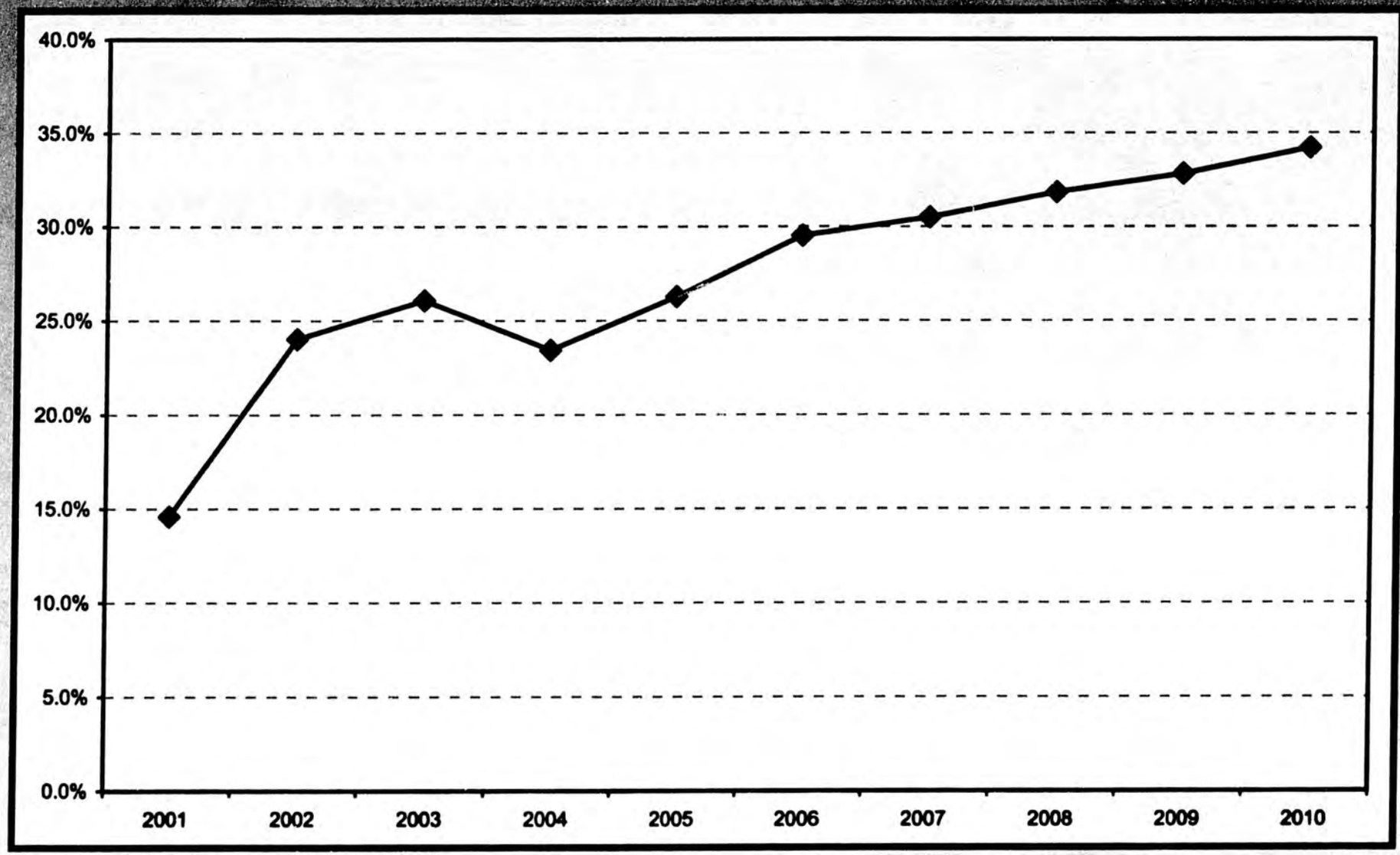
Figure 10

Alaska Regulated Pipelines



Source: Division of Oil and Gas, January 2002

krb 1/02



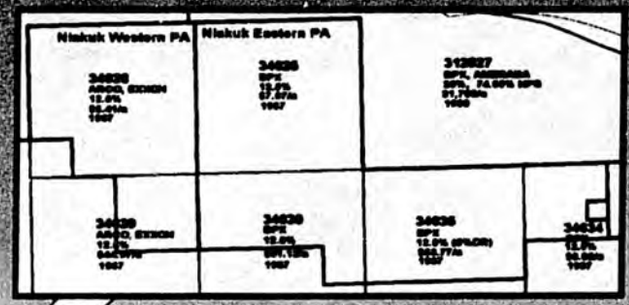
Source: DOR, Revenue Sources Book, Fall 2001

krb 1/02

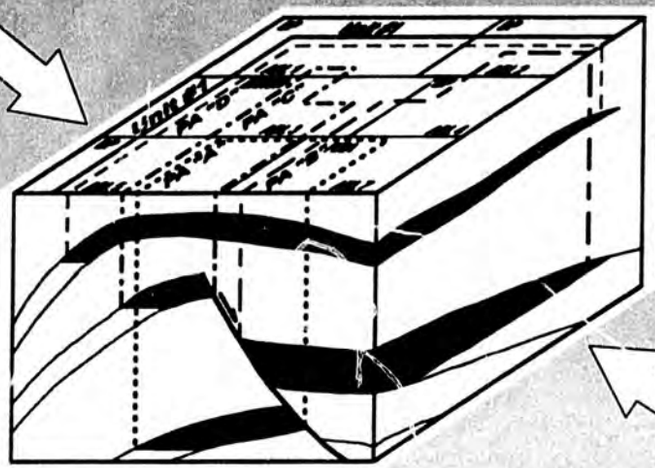
[illegible] create 3-D pictures of oil fields and royalty shares

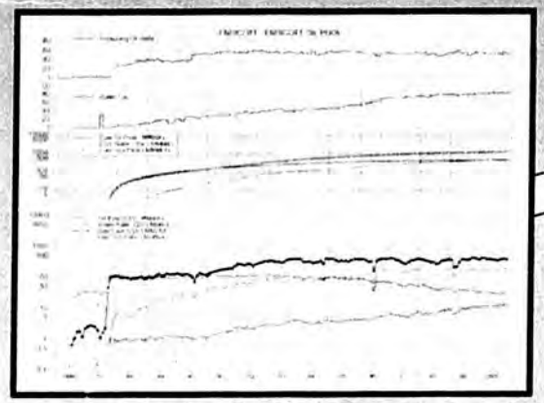


Geologic Data
(Well logs, Directional Surveys, Geochemistry, Paleontology, & Formation data)

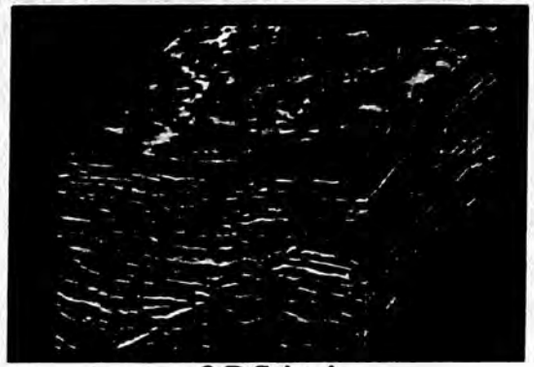


Royalty, Lease, Unit/Participating Areas, Ownership & Economic Data



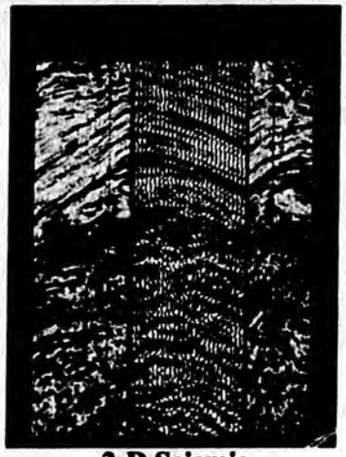


Engineering & Production Data

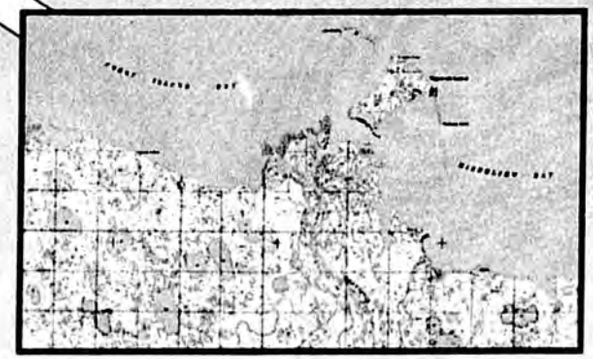


3-D Seismic

Geophysical Data
(Seismic, Gravity, Magnetic, Velocity, & Shothole data)



2-D Seismic

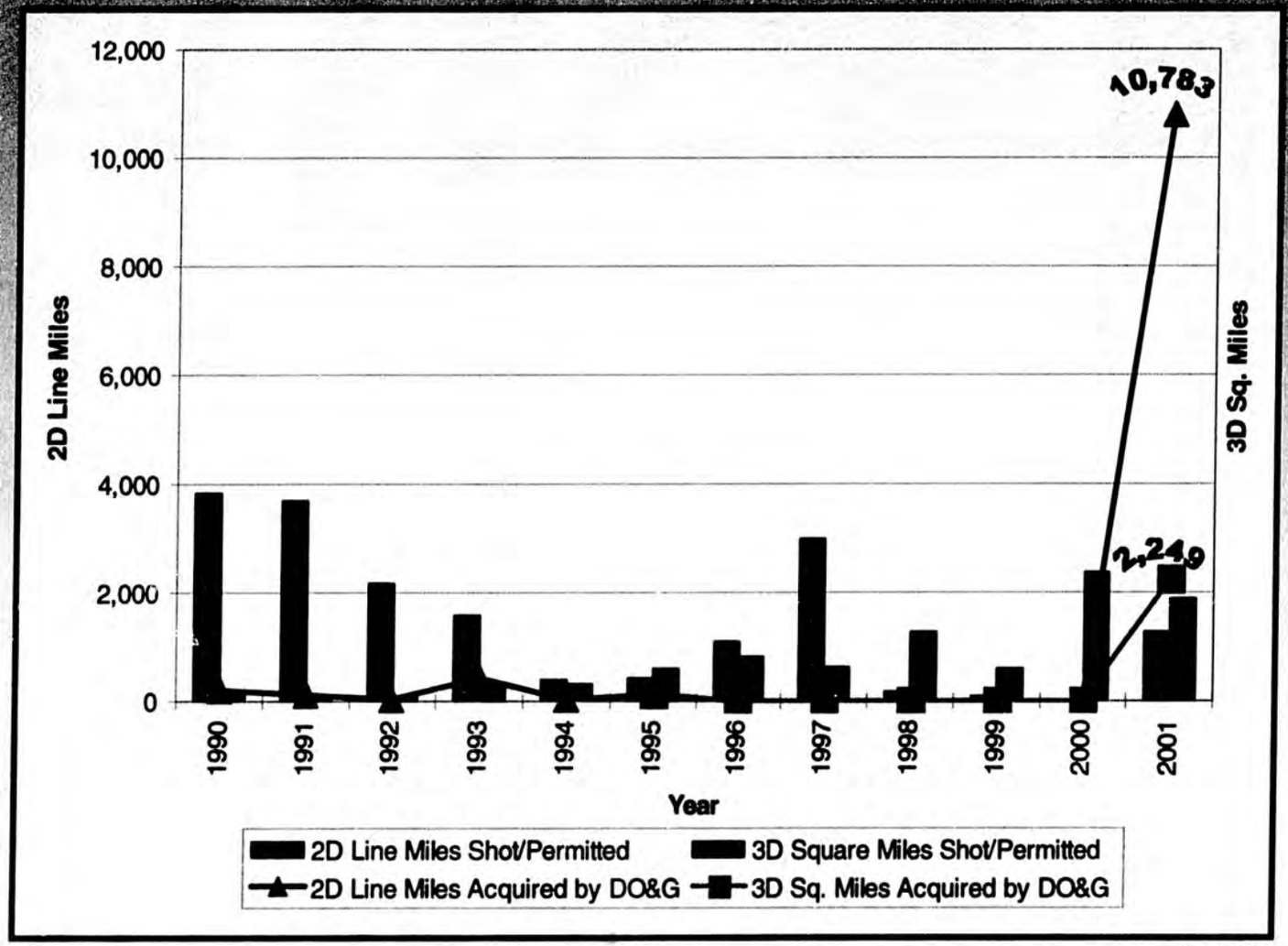


Geographic Information;
Cultural & Physical Data
Aerial & Satellite Imagery

mep 02/02

Seismic Data Sheets

1990 - 2001



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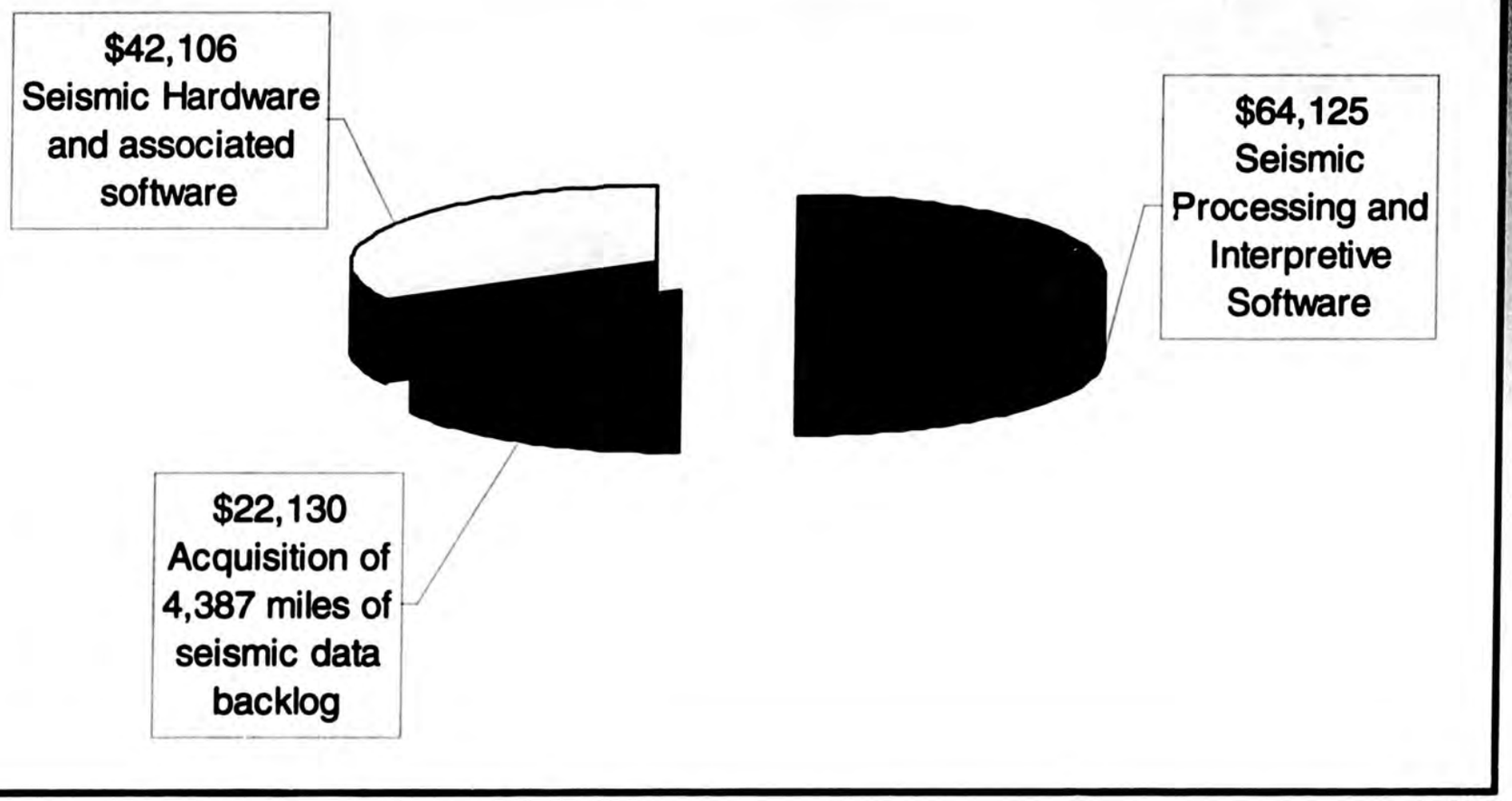
FY02 Seismic Acquirement Expenditures



jrc 01/02

Exploration Licensing

Proposed – Susitna Valley

- Forest Oil Corp. submitted two proposals
- 873,600 Total Acres, located west of Susitna R.
- Total Exploration Commitment over $5 Million
- Final Finding and Decision – February 2002

Proposed – Nenana Basin

- Andex Resources submitted only proposal
- 499,800 Acres, located north and west of Nenana
- Exploration Commitment = $2.5 Million
- Preliminary Finding – February 2002
- Final Finding and Decision – Late Summer 2002

jjh 11/01

Alaska Natural Gas In-State Demand Study

Prepared on Behalf of the Alaska Department of Natural Resources

David E. Dismukes, Ph.D.

With Contributions from:

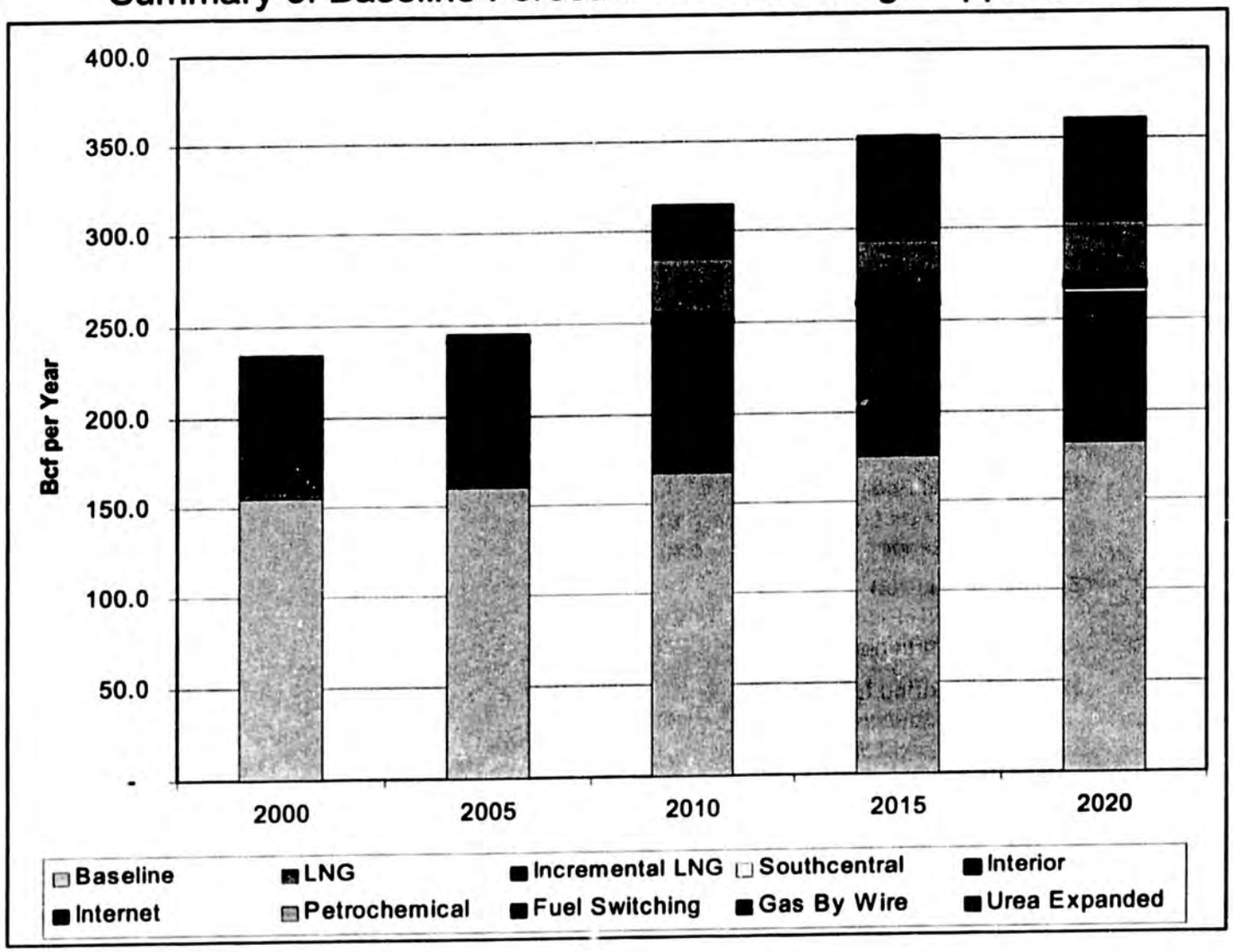
Dmitry V. Mesyanzhinov, Ph.D.
Elizabeth A. Downer
Stephen Chriss
Jeffrey M. Burke

Report Prepared by the Collaboration of:

Econ One Research, Inc.
Los Angeles, California
and
Acadian Consulting Group
Baton Rouge, Louisiana

January 23, 2002

Summary of Baseline Forecast and New Usage Opportunities



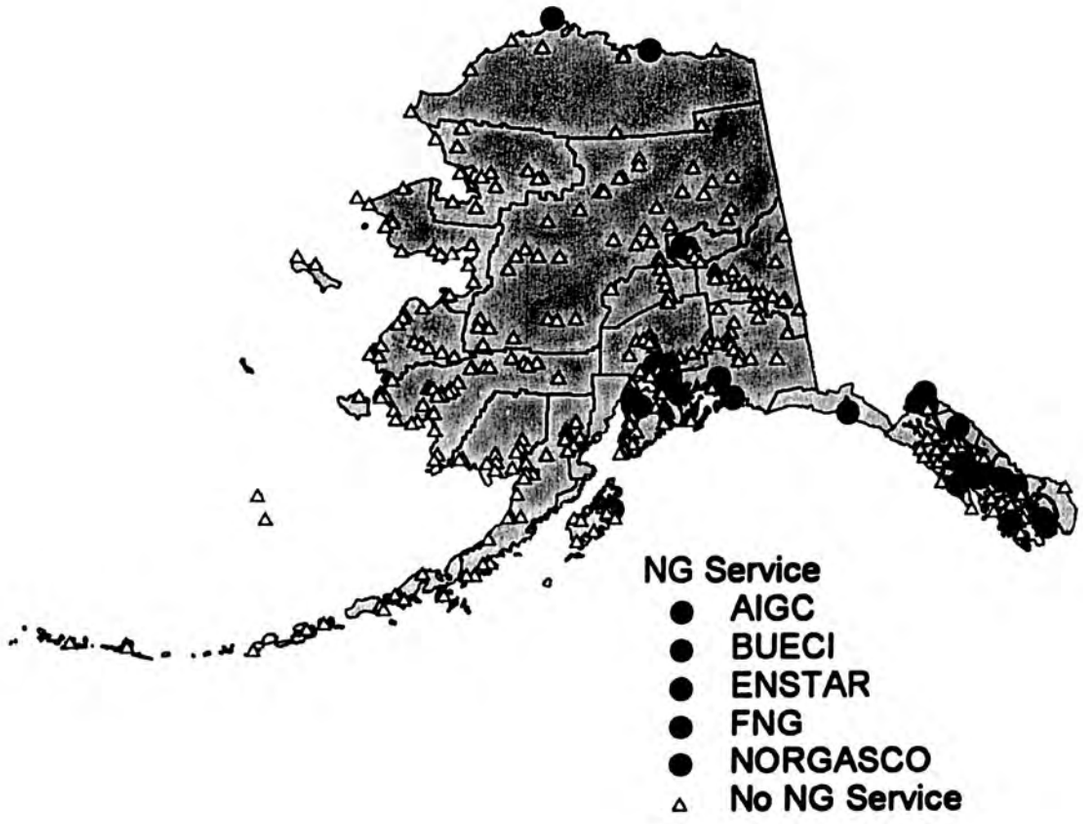
Alaska DNR

Summary of Baseline In-State Natural Gas Demand and Potential for Growth (Bcf per Year)

Instate Baseline in 2000	Residential	Commercial	Industrial	Electric Power	Total
			(Bcf per Year)		
Southcentral	16.70	18.57	151.24	35.04	**221.54**
Interior	0.07				**0.07**
North Slope	0.75	10.00		0.62	**11.37**
	17.52	28.57	151.24	35.66	**232.98**
	7.5%	12.3%	64.9%	15.3%	**100.0%**
Potential for Growth in 2020					
Baseline	7.9	6.3	8.0	5.1	**27.3**
Expanded Service					
Southcentral	2.20				**2.20**
Interior	4.30				**4.30**
Existing Industrial					
LNG Plant			2.80		**2.80**
Ammonia-Urea Plant			7.20		**7.20**
New or Expanded Industry					
Ammonia-Urea Plant			30.00		**30.00**
Internet Server			4.30		**4.30**
Petchem			27.00		**27.00**
Fuel Switching for Power					
Interior (only)				15.00	**15.00**
Gas by Wire (central station)					
Interior (only)				12.50	**12.50**
TOTAL in 2020, All Sectors:					**365.53**

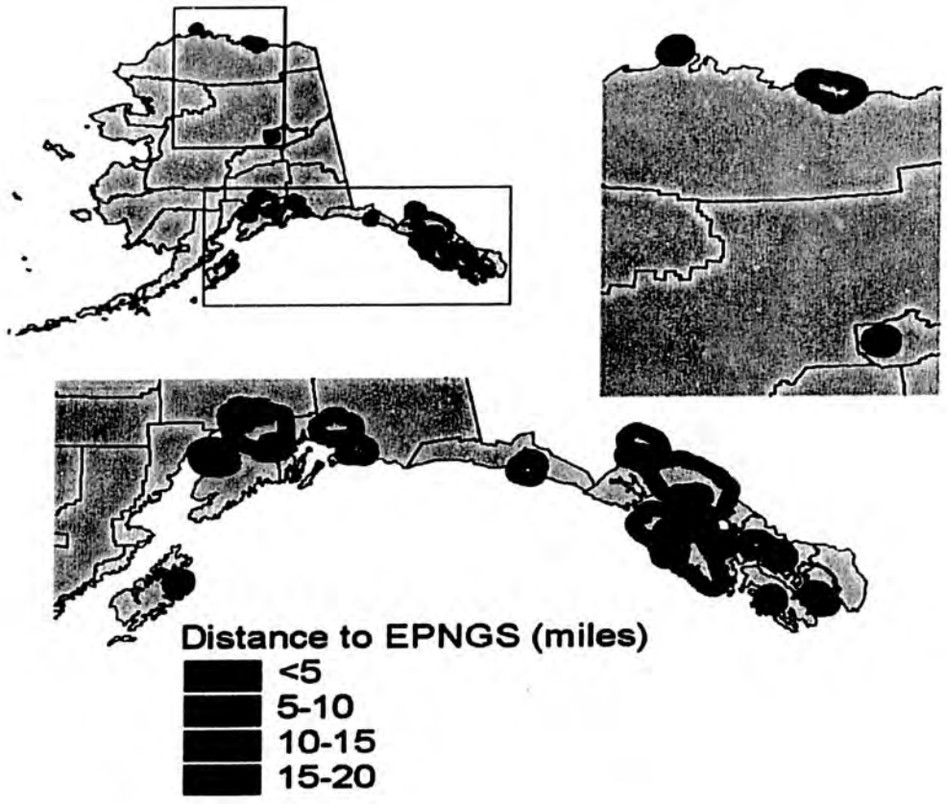
Alaska DNR

Geographic Distribution of Natural Gas Service in Alaska
Figure 6.2



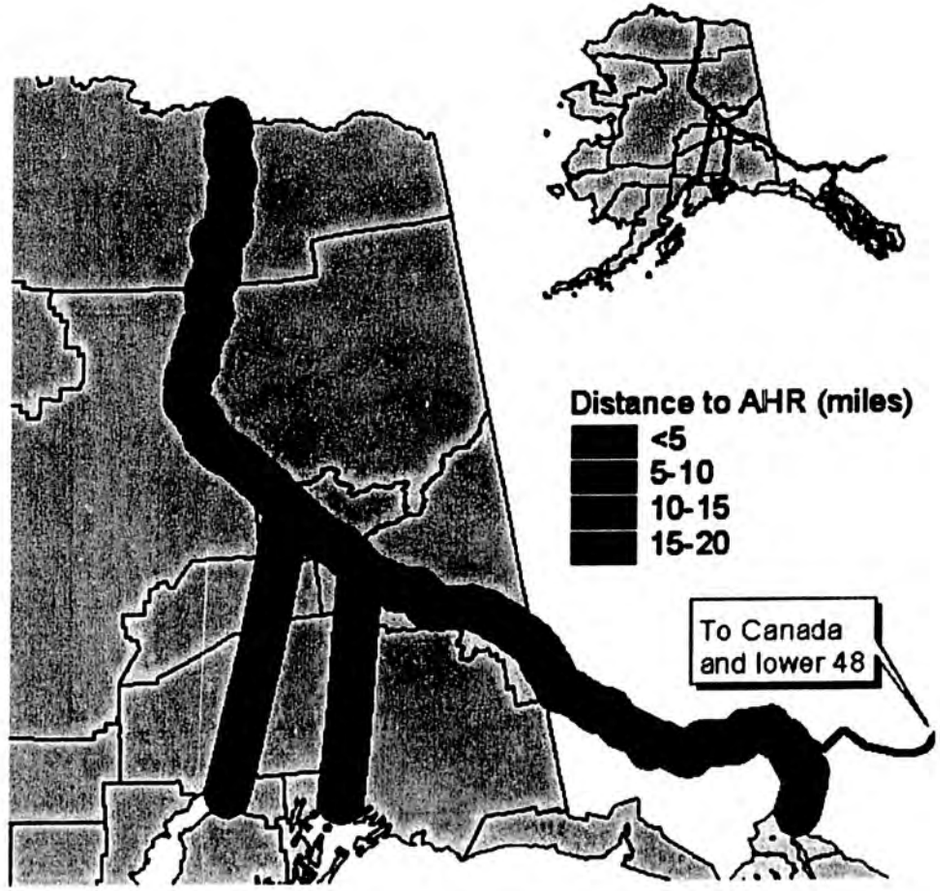
Alaska DNR

Proximity Zones around Existing and Proposed Natural Gas Systems (EPNGS)
Figure 6.6



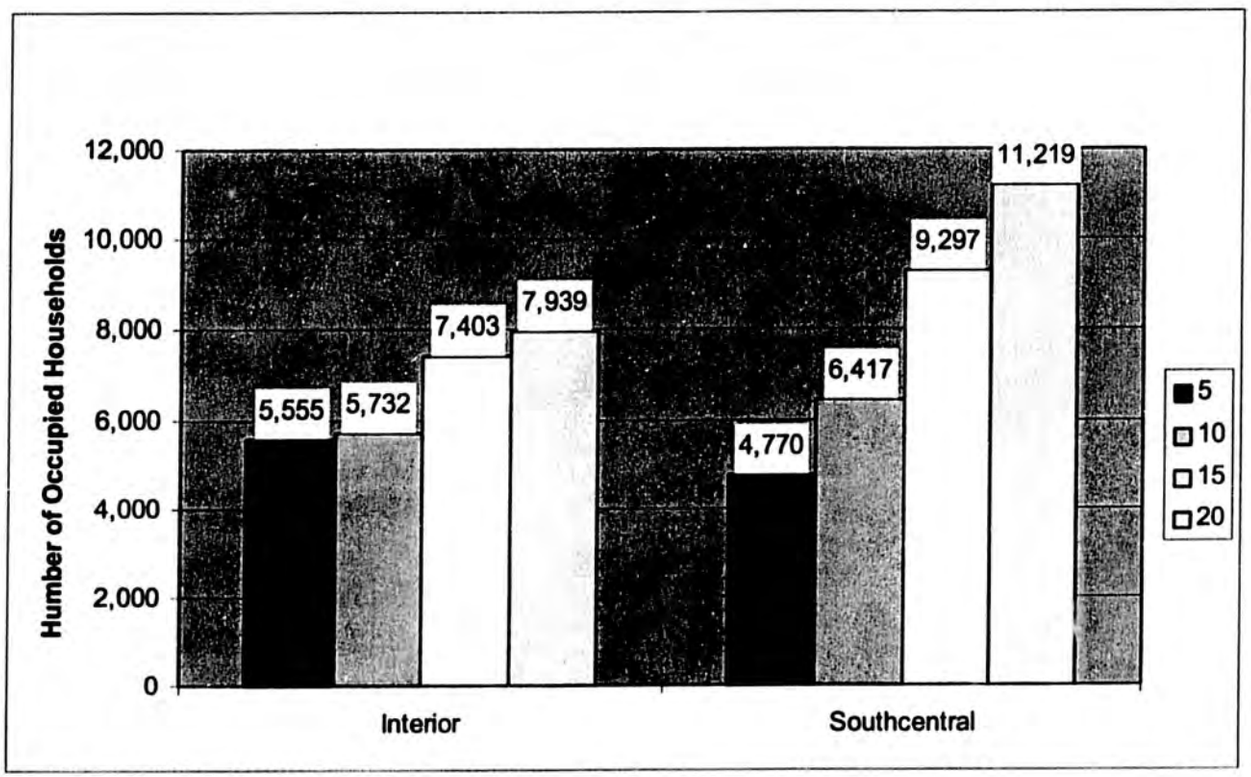
Alaska DNR

Proximity Zones Areas Around the Proposed Alaska Highway Route (AHR)
Figure 6.7



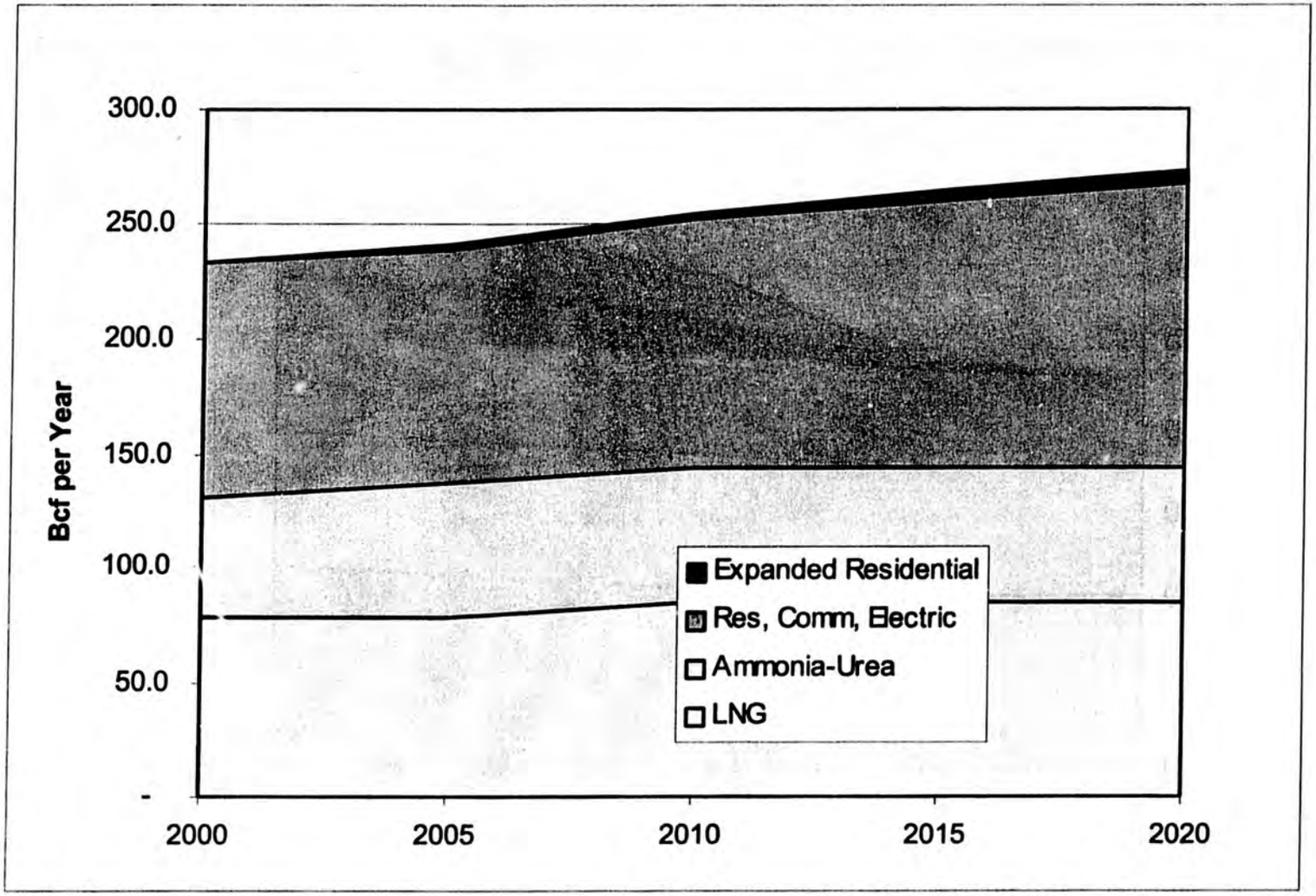
Alaska DNR

Distribution of Interior and Southcentral Households Without Existing or Proposed Access to Natural Gas Service by Proximity to Natural Gas Service and AHR



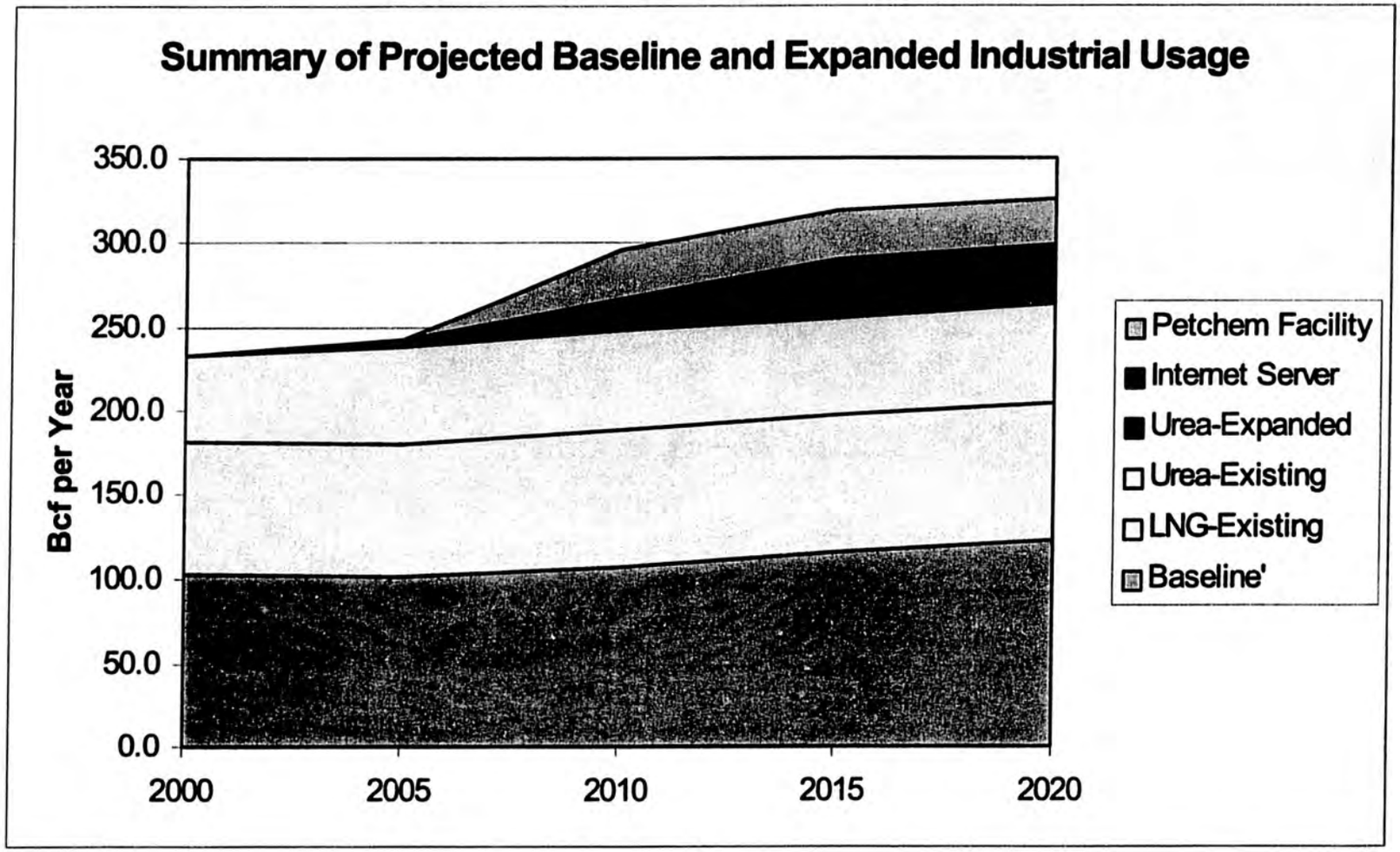
Alaska DNR

Summary of Expanded Residential and Commercial Gas Usage (Chapter 6)



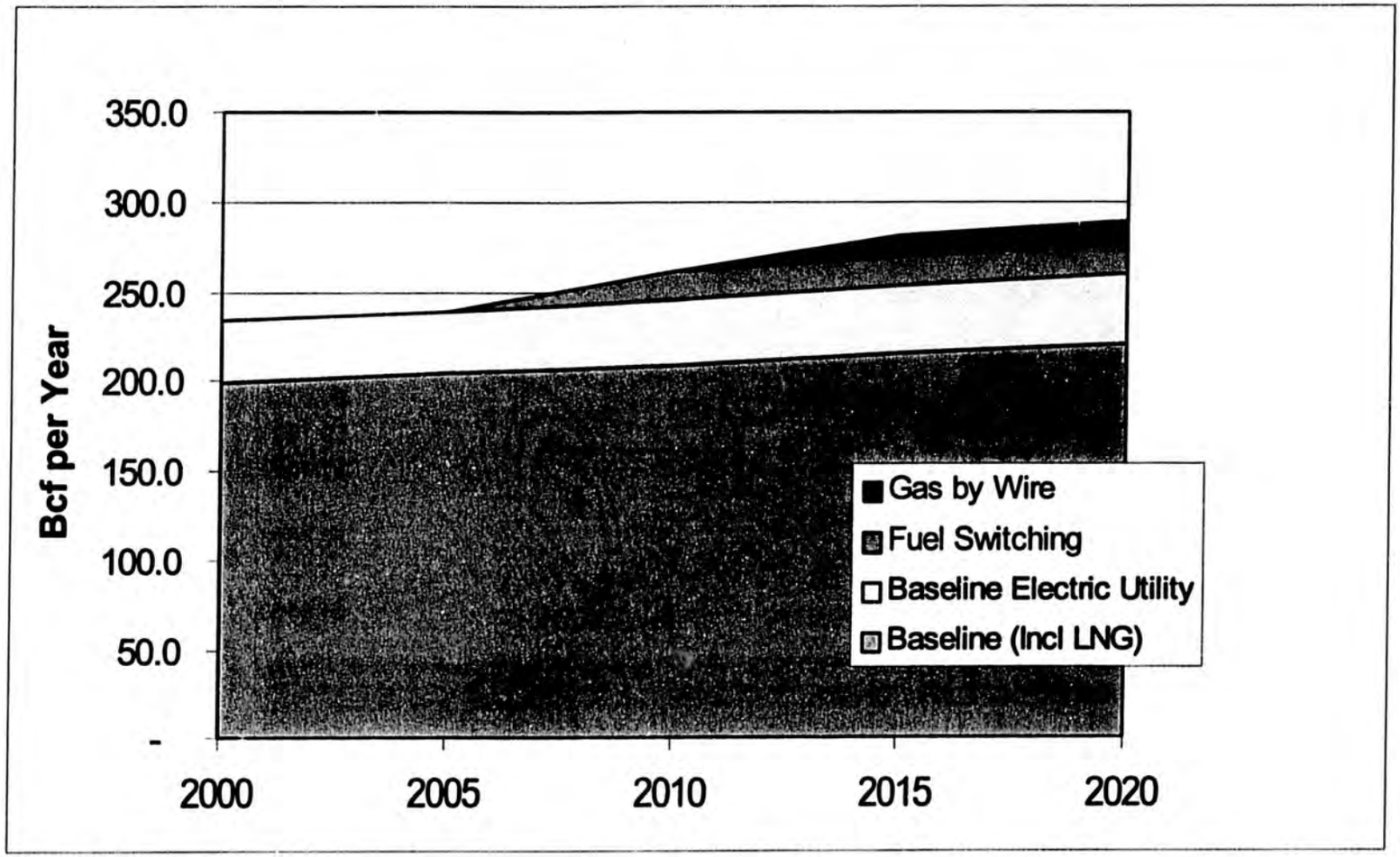
Alaska DNR

Summary of Projected Baseline and Potential Industrial Usage
Chapter 7



Alaska DNR

Projected Baseline and Expanded Electric Power Gas Usage: Fuel Switching and Gas by Wire in the Interior Region Chapter 8

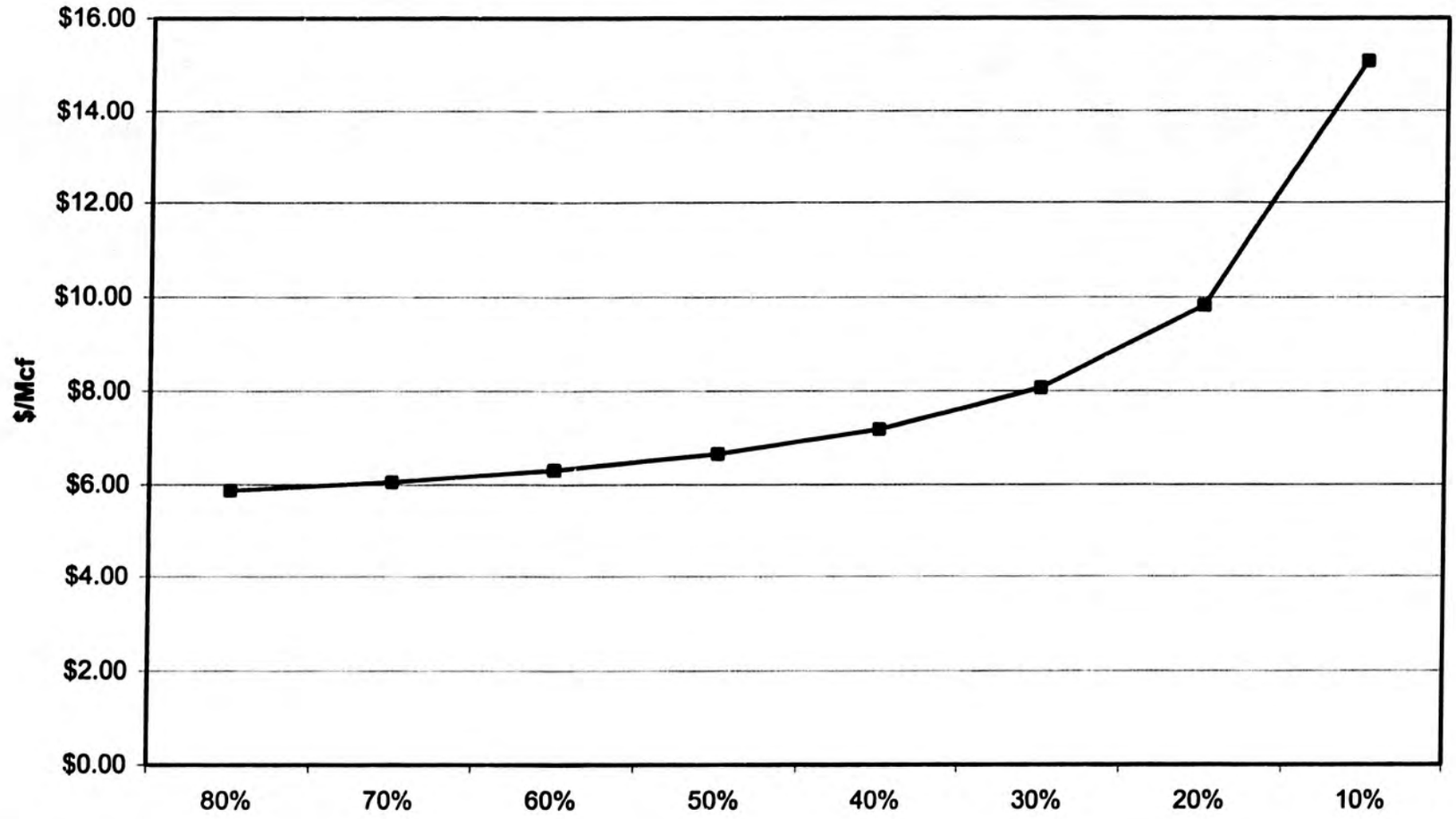


Alaska DNR

Estimated System Delivered Cost for the Interior (Fairbanks) Region
Table 9.1

Fairbanks System Cost per Mcf	
Transportation -- ANS Conditioning Plant to Fairbanks Meter Station	$1.0000
Levelized Meter/Step-Down Capital Cost	$0.0307
Levelized Transportation Cost	$0.0307
Levelized Distribution Costs	$1.2538
Transportation Meter Station O&M	$0.0545
Transportation O&M	$0.1091
Distribution O&M	$1.4857
Total T&D Cost	$3.9646
Commodity Cost	$1.9100
Total Delivered Cost (Average Retail Rate)	**$5.8746**

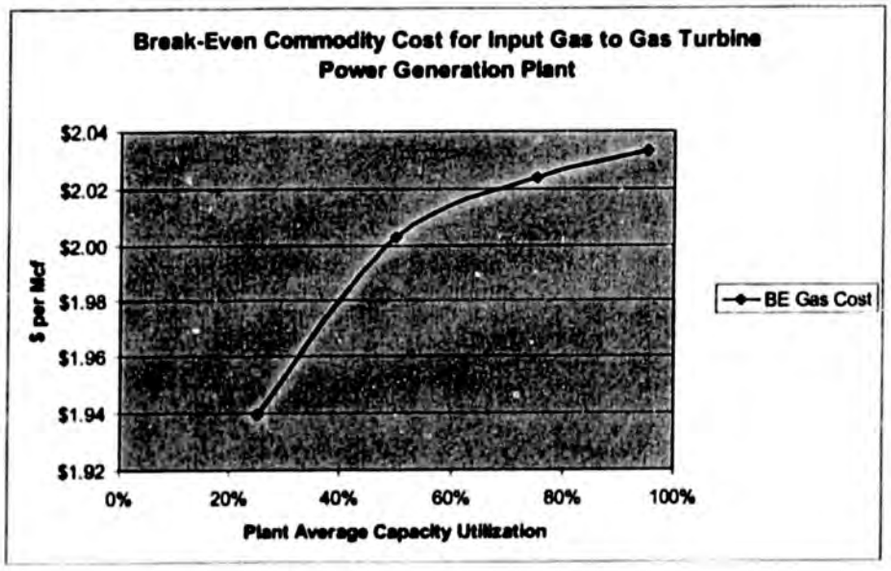
Estimated Delivered Cost (Average Retail Rates) versus Penetration Rates – Interior Region



Alaska DNR

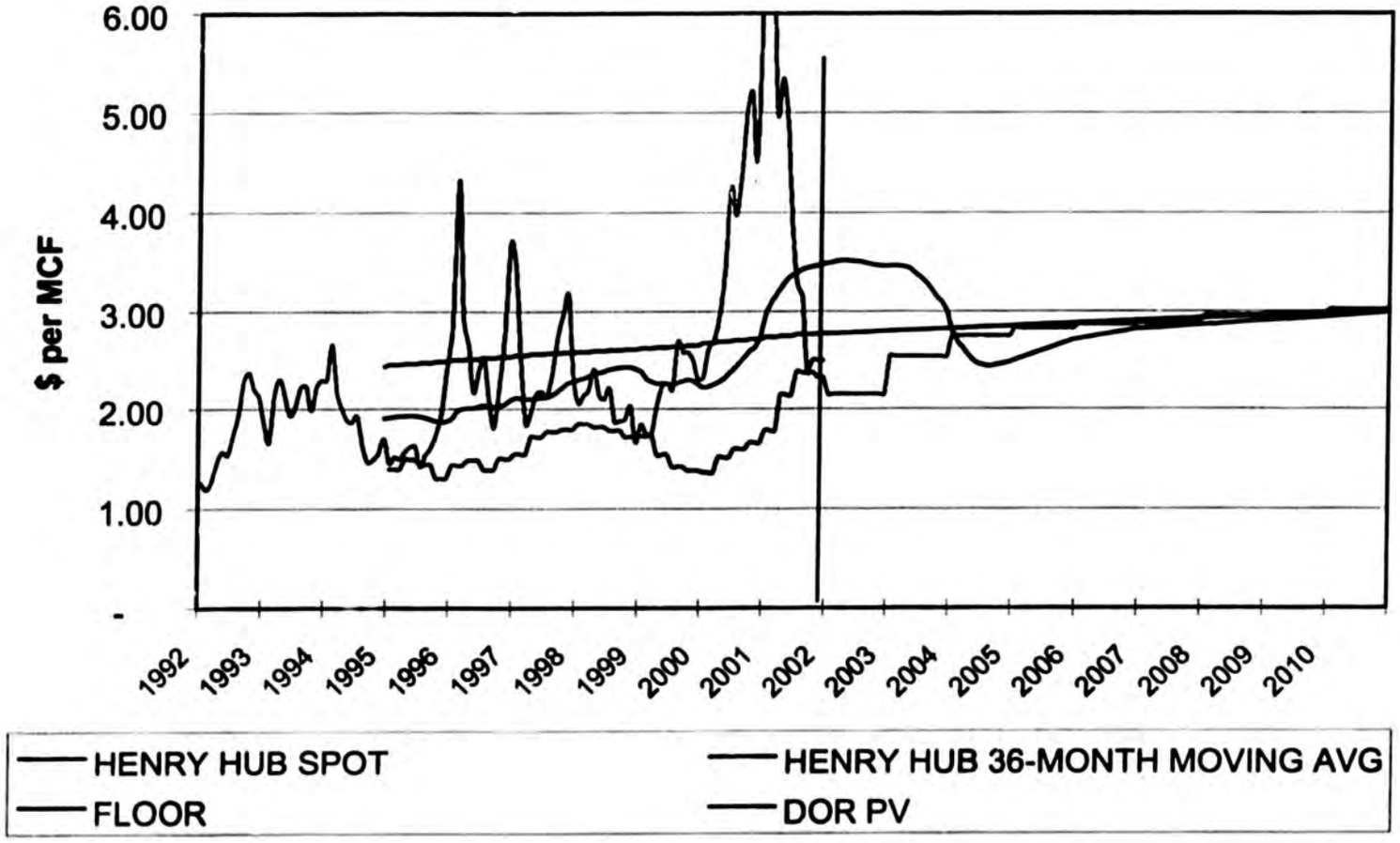
Cost Savings from Fuel Switching Under Different Average Capacity Assumptions
Table 9.6

Capacity Factor	Gas Usage (Mcf)	Savings Per kWh Low	Savings Per kWh High	Total Savings
95%	30,284,049	0.00360	0.00870	8,875,417
75%	23,908,460	0.00350	0.00850	6,794,093
50%	15,938,973	0.00310	0.00820	4,192,437
25%	7,969,487	0.02000	0.00700	1,590,781



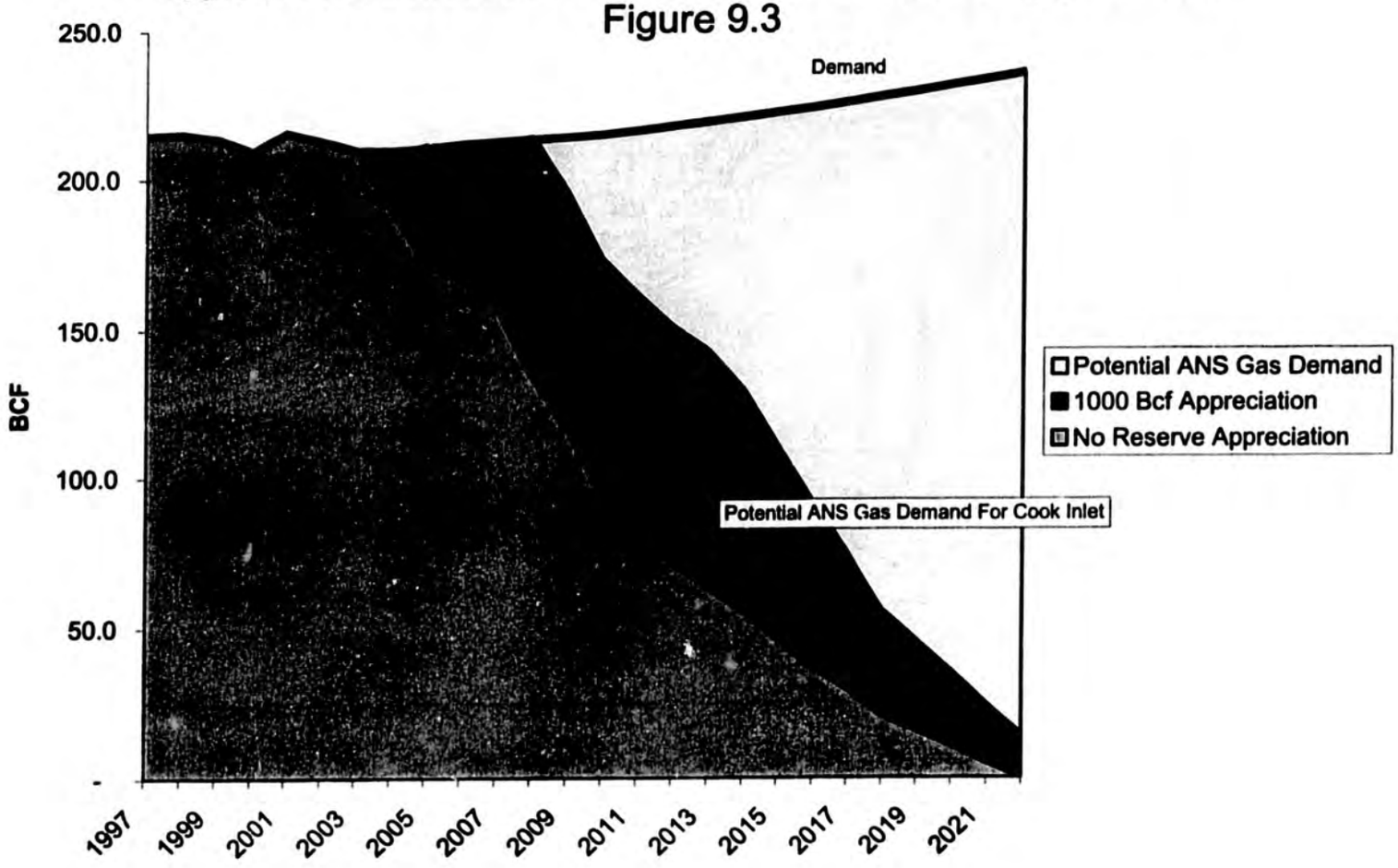
Alaska DNR

Henry Hub 36-Month Moving Average with UNOCAL-ENSTAR Price Floor
Henry Hub Spot Price and DOR Prevailing Value
Figure 9.2



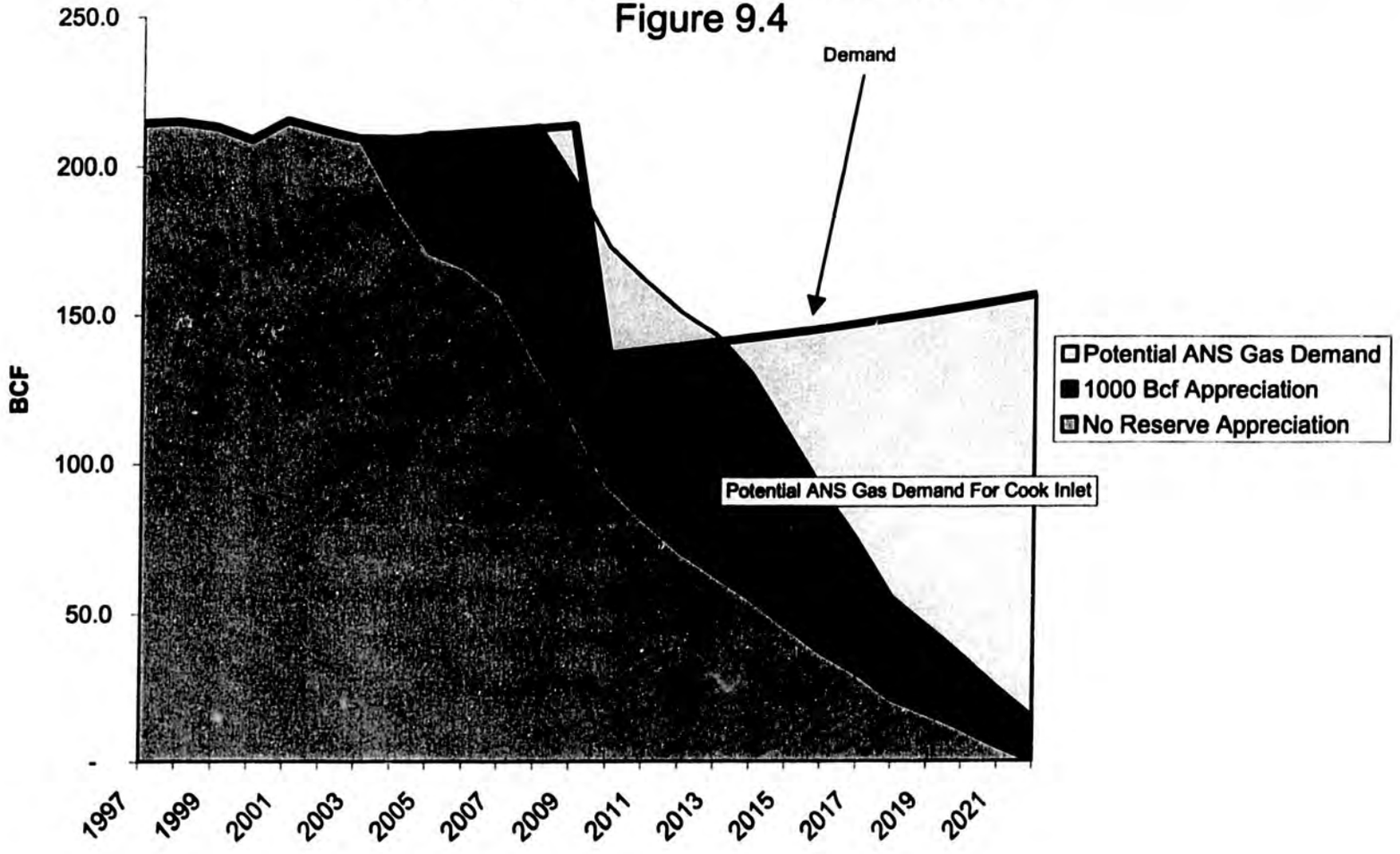
Alaska DNR

Projected Cook Inlet Supply and Demand
Typical Production Scenario with 1 Tcf Reserve Appreciation
Figure 9.3



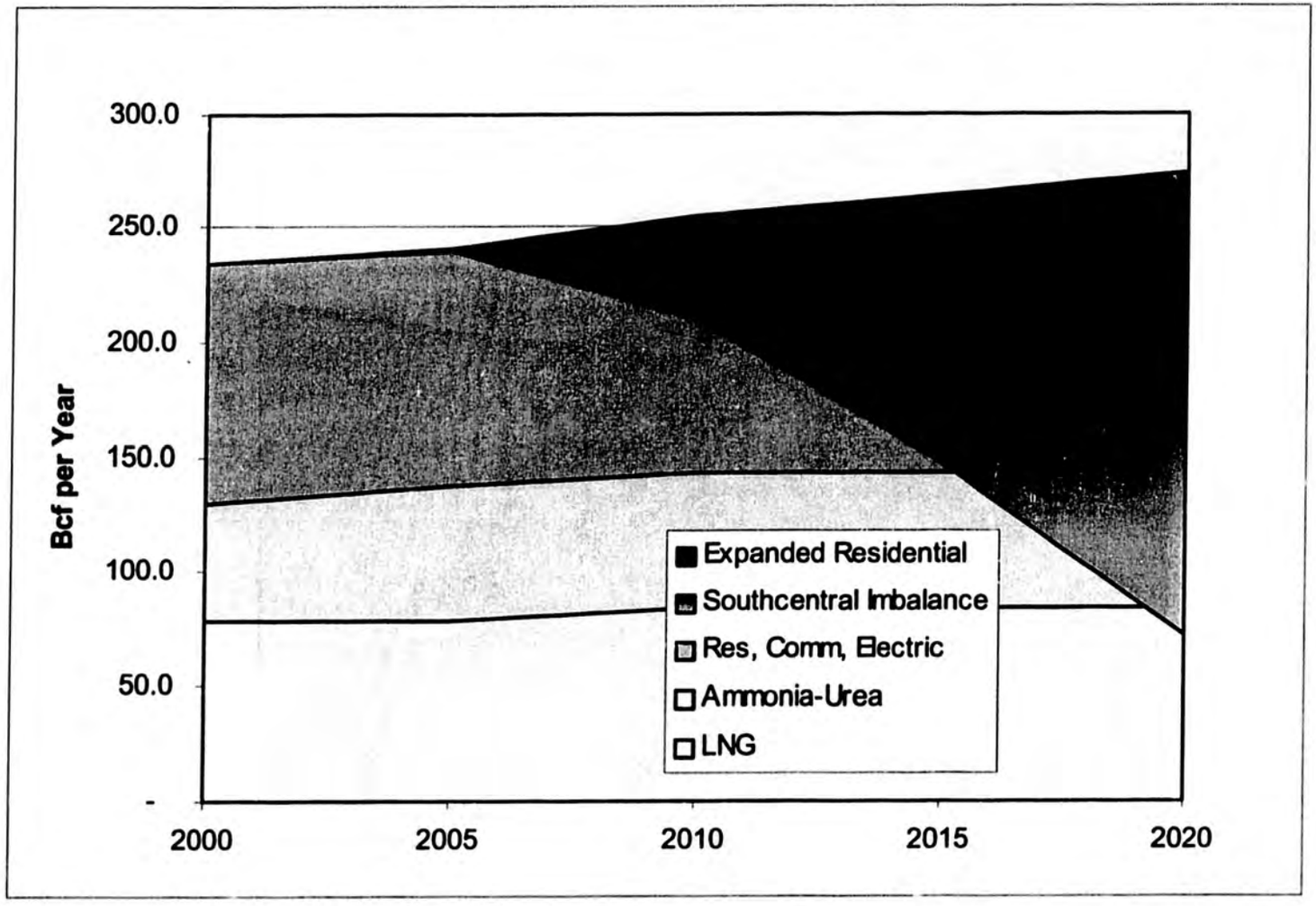
Alaska DNR

Projected Cook Inlet Supply and Demand
LNG Export License Renewal Denied
Figure 9.4



Alaska DNR

Southcentral Gas Demand-Supply Imbalance



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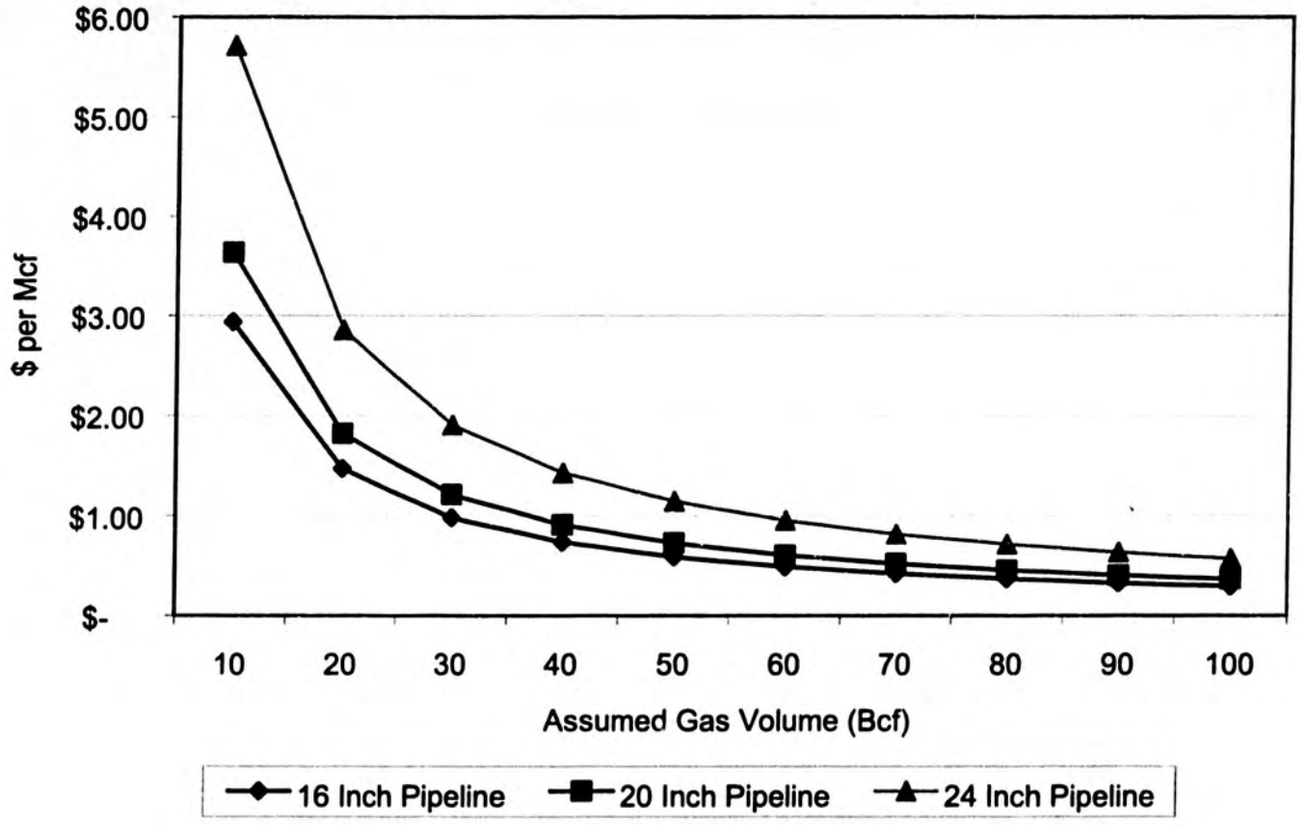
Estimate Pipeline Transportation Costs Under Different Volumetric Assumptions
Figure 9.5



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ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

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Senator Rick Halford
Senator Pete Kelly
Senator Johnny Ellis

Representative Joe Green, Vice-Chair
Representative Brian Porter
Representative Scott Ogan
Representative John Davies

MEMORANDUM

To: Joint Committee on Natural Gas Pipelines

From: Senator Torgerson, Chair

Date: February 12, 2002

Re: Hogan & Hartson report on federal legislative developments

This memorandum provides a brief description of federal legislative activities that are on the immediate horizon, including the Senate's consideration of a comprehensive energy bill. There was no activity from last week to report on.

I. Senate Energy Legislation

The Senate's consideration of a comprehensive energy bill, S. 1766 (or a revision of this bill), may begin as early as February 14, after the Senate has completed action on a massive agricultural policy bill that is currently on the floor. However, even if the Senate is able to begin consideration of the energy bill this week, most of the substantive amendments and votes are likely to be delayed until the Senate returns from its week long Presidents Day Recess, the week of February 25. Senator Kerry (D-MA) and others have promised a filibuster if ANWR drilling provisions are added to the bill, and Senator Murkowski (R-AK) has promised a filibuster if the bill does not contain such a provision. There is always the possibility that these and other controversial issues might prevent final passage of an energy bill in the Senate.

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A. Tax Issues

Leading up to the Senate's debate of the energy bill this week, several Senate Committees will consider topics that are not currently included in S. 1766, but which could be added during Senate floor consideration or as part of Senate Majority Leader, Tom Daschle's (D-SD) revisions to the bill. One of these components is the energy tax provisions, which are expected to be marked-up by the Senate Finance Committee on Tuesday or Wednesday of this week. The comprehensive energy bill approved by the House, H.R. 4, contains approximately $35 billion in tax incentives for energy production and conservation. Although we do not know for certain what specific provisions will be included in the Senate's bill, the following provisions, which are also included in H.R. 4, are being given serious consideration.

- A proposal that would establish a statutory 7-year recovery period and class life of 10 years for natural gas gathering lines. In addition, the proposal would provide that there would be no adjustment to the allowable amount of depreciation for purposes of computing a taxpayer's alternative minimum tax with respect to such property.

- A proposal that would establish a statutory 10-year recovery period and a class life of 20 years for natural gas distribution lines. In addition, the proposal would provide that there would be no adjustment to the allowable amount of depreciation for purposes of computing a taxpayer's alternative minimum tax with respect to such property.

- A proposal that would extend the section 29 tax credits for certain non-conventional fuels produced at wells placed in service after the date of enactment and before January 1, 2007. Qualifying fuels would be oil from shale or tar sands, gas from geopressured brine, Devonian shale, coal seams or a tight formation. The value of the credit would be $3.00 per barrel (or BTU oil barrel equivalent) for production in 2001 and 2002 and would be indexed for inflation beginning in 2003. The proposal would also allow the tax credit for production from certain existing wells (any well drilled after December 31, 1979 and before January 1, 1993). Landfill gas sold to a third party from facilities placed in service after June 30, 1998 and before January 1, 2007 would also be eligible for the section 29 credit. The credit would be capped at production equal to a daily average of 200,000 cubic feet of gas (or barrel or oil equivalent).

B. Pipeline Safety

Senator McCain (R-AZ) intends to offer the provisions of S. 235 as an amendment to the Senate's comprehensive energy bill. S. 235, the Pipeline Safety Improvement Act, passed the Senate February 8, 2001, by a vote of 95-0. This bill would, in part, reauthorize the Pipeline Safety Act through 2004, increase penalties for safety violations, and require pipeline operators to test the

adequacy of pipelines at least every five years. Senator McCain believes that attaching S. 235 to the comprehensive energy bill would increase its changes of clearing Congress, since the House has been slow to act on similar legislation.

The Chairman of the House Transportation and Infrastructure Committee, Representative Don Young (D-AK), along with the Chairman of the Energy and Commerce Committee, Representative Billy Tauzin (R-LA), introduced a new pipeline safety bill, H.R. 3609, on December 20, 2001. In general, H.R. 3609 is much less prescriptive then S. 235 and does not contain the five-year testing mandate that is found in the Senate bill. A hearing on pipeline safety issues before the House Transportation and Infrastructure Committee is scheduled for February 13.

C. Other Provisions in S. 1766

- Provisions that would establish an expedited process for FERC to consider and act on any application to construct a pipeline to transport Alaska natural gas. The bill's Alaska pipeline provisions also include restrictions on court venue, deadlines for performing environmental impact statements, and an authorization for federal loan guarantees.

- Provisions that would prohibit the listing of an operating natural gas pipeline under the National Historic Preservation Act, unless the owner consents to the listing.

- Provisions that would require the development of an interagency memorandum of understanding to expedite environmental review and permitting of pipeline projects.

II. Climate Change

The Bush administration is expected to release its long-awaited policy on climate change this week. Published news reports indicate that the policy will emphasis the need for more research on both the science of understanding climate change and the means of mitigating its effects. The policy is also expected to recommend flexible, gradual goals for greenhouse gas reductions. The Economic Report of the President, released February 5, 2002, briefly describes a flexible approach for controlling greenhouse gases that would index emission targets to economic output or other measures of economic activity. Another approach described in the report would express targets or goals in terms of greenhouse gas emission intensity (*i.e.*, the amount of emissions per unit of economic activity).

ALASKA STATE LEGISLATURE

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12 Proposals on Federal Legislation

Proposal # 1

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress reaffirm that the Alaska Natural Gas Transportation Act (ANGTA) is the prevailing law with respect to a transportation system for delivery of Alaska natural gas to Alaska, the contiguous States, and other markets, and the construction and initial operation of that system.

The Joint Committee on Natural Gas Pipelines also respectfully requests that Congress allow certain amendments to ANGTA to modernize the act without changing the basic nature and general route of the approved transportation system or otherwise preventing or impairing in any significant respect the expeditious construction and initial operation of the transportation system.

Justification for Proposal # 1

Before the enactment of ANGTA there were three competitive proposals for an Alaska Natural Gas Transportation System. Specifically those proposals were:

1) the Arctic Gas Project, which proposed an overland pipeline extending from Prudhoe Bay, across the North Slope of Alaska to the Canadian Mackenzie Delta and thence southerly through Canada to the lower forty-eight states;
2) the El Paso LNG Project, which proposed an overland pipeline extending from Prudhoe Bay to Southern Alaska, where the gas would have been liquefied and transported by tankers to terminals in the western United States; and
3) the Alcan Pipeline Project, referred to in Canada as the Alaska Highway Pipeline Project, which proposed an overland pipeline

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extending from Prudhoe Bay to Fairbanks, Alaska, and thence southeasterly through western Canada to the lower forty-eight states.

All of these proposals were filed under the Natural Gas Act, debated by FERC, and Congress passed ANGTA, which authorized the President to select a route. The President then approved the ALCAN route and entered into a treaty with Canada, which were later confirmed by Congress. The Canadian Parliament also passed the Northern Pipeline Act, the equivalent of ANGTA. ANGTA was never repealed. In fact, in 1992 the federal inspector recommended that ANGTA be abolished, but Congress rejected that notion.

Proposal # 2

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress adopt provisions that prohibit the over-the-top route through the Beaufort Sea as a pipeline route.

Justification for Proposal # 2

- The Alaska Legislature has banned this route in Senate Bill 164.
- The House of Representatives in Congress has adopted an amendment in the Energy Bill to ban this route.
- This route seriously decreases the benefits Alaskan's will receive from the development of natural gas.
- The North Slope Borough and the Alaska Eskimo Whaling Captains oppose this route.

Proposal # 3

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress create a mechanism for allowing the transparent and fair distribution of the costs allowed to be included in the tariffs associated with a conditioning plant(s).

Justification for Proposal # 3

Other producers will likely discover gas downstream from access to a conditioning plant in Prudhoe Bay that will require them to construct an additional conditioning plant. These producers will need to be treated fairly with regard to tariffs to encourage development and exploration of all North Slope gas resources.

Proposal # 4

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to eliminate the Dempster-Lateral route from provisions in ANGTA, if necessary.

Justification for Proposal # 4

The original version of ANGTA included approval for the construction of a Dempster-Lateral pipeline to deliver natural gas to market from the Northwest Territories. The Northwest Territories has developed plans for their own pipeline route to Alberta, making the Dempster-Lateral line obsolete.

Proposal # 5

The Joint Committee on Natural Gas Pipelines respectfully requests that the Congress pass legislation that limits tariff charges for prior work to compensation for work done that does not have to be duplicated and which is deemed appropriate to the current transportation system.

Justification for Proposal # 5

The current owner of the authorizations under ANGTA is Foothills Pipeline Ltd. Previously, Foothills had several partners, which over time have withdrawn from the partnership. The withdrawn partners spent funds in support of the ANGTA route and have filed documents with the FERC to include recovery of those costs in any tariff for transportation of Alaska natural gas. Foothills has been negotiating with the withdrawn partners to resolve this outstanding liability. However, those negotiations have not been successful to date.

Foothills and its partners should be compensated for the work done in furtherance of the ANGTA system that does not need to be duplicated. If the work needs to be redone or modernized, they should not be entitled to collect for the funds previously expended. Accordingly, the Joint Committee should support this request.

Proposal # 6

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress pass legislation to assure that Alaska have fair and reasonable access to gas produced within the State and to create a joint board consisting of members appointed from the Federal Energy and Regulatory Commission and the Regulatory Commission of Alaska to recommend access and tariffs that affect the state of Alaska.

Justification for Proposal # 6

Unlike the Trans-Alaska Transportation System for oil, the Natural Gas Act does not provide for the Regulatory Commission of Alaska to set rates for gas used in Alaska. Although section 13(b) of ANGTA provides that the state is authorized to ship its royalty gas on the approved system for use within Alaska and to withdraw such gas from the interstate market for use within Alaska, it does not deal specifically with how Alaska delivery points along the line will be approved. Access to gas is necessary for social and economic development of Alaska. Alaska's regulatory commission should be part of a team that determines how intra-state access and rates are determined.

Proposal # 7

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to develop a formula that would allow for the setting of different tariff rates for natural gas distribution points along the route. (HUBS)

Justification for Proposal # 7

Alaska is studying different proposals for usage of natural gas within the state, including several proposals for LNG facilities, a petrochemical plant, several GTL plants, and in-state usage by communities. It is important to be able to set the tariff at different rates to allow these take off points.

Proposal # 8

The Joint Committee on Natural Gas Pipelines respectfully requests that the Congress pass legislation to assure that gas producers that do not have an ownership interest in the pipeline have fair and reasonable access to space on the pipeline and the ability to obtain expansion capacity of the pipeline.

Justification for Proposal # 8

ANGTA originally precluded the Producers from participating in the ownership of the gas pipeline. In 1981, a waiver was sought and obtained by President Reagan to permit the Producers to have an ownership share in the pipeline. Their participation, however, had to be approved by the FERC and could be approved only after consideration of the advice from the Attorney General and upon a finding by FERC that the participation would not (a) be inconsistent with the antitrust laws or (b) in and of itself create restrictions on access to the transportation system for non-owner shippers or restrictions on capacity expansion.

Alaska has much more gas than that contained in known fields. Current estimates provide that there is greater than 100 tcf of gas undiscovered on the Alaska North Slope. Currently, companies are considering exploring for such gas. If discoveries are made, that gas will need access to the pipeline on fair and reasonable terms. If significant discoveries are made after the initial capacity is filled, the pipeline will need to be expanded and any expansion request needs to be determined on fair and reasonable terms. Accordingly, the law must be clear that the FERC has the authority to make such determinations.

Proposal # 9

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to approve a provision for project labor agreements.

Proposal # 10

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to approve a preference for qualified Alaskan businesses for the construction and maintenance of a natural gas pipeline.

Proposal # 11

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress pass legislation that prohibits tax incentives for LNG from sources outside of North America.

Justification for Proposal # 11

The President and Congress have recommended a variety of incentives as part of a national energy policy. Alaska natural gas is in competition with LNG imported from foreign sources to supply gas to the lower 48 states. It is the policy of the United States to reduce dependence on foreign energy sources. Accordingly, Congress should not pass any law that gives tax incentives to facilities importing LNG from sources outside North America. Rather, Congress should enact incentives that benefit production from the frontier areas of the United States, including Alaska. Otherwise, United States gas in frontier areas may be stranded.

Proposal # 12

The Joint Committee on Natural Gas Pipelines respectfully requests that the Congress pass legislation providing a tax incentive that allows for an accelerated depreciation schedule of seven years for Alaska natural gas brought to United States markets.

Justification for Proposal # 12

The President and the Congress has recommended a variety of incentives as part of a national energy policy. It is the policy of the United States to reduce dependence on foreign energy sources. Alaska has significant gas resources that can reduce that dependence and bring cleaner burning fuel to United States markets. However, the construction of a pipeline to the lower 48 would cost billions of dollars and involve significant risk. Accordingly, Congress should enact tax incentives, such as accelerated depreciation, investment tax credits, and downside price tax credits that benefit gas production from Alaska.

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2956 SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPLINES, 2001-02

Alaska Gas and NGL—Economic Analysis of Value and Royalty

Report prepared for the Alaska Department of Natural Resources

Roger Riddlehoover and Barry Pulliam

Econ One Research, Inc
Los Angeles, California

January 2002

Economic Issues

•How are gas and NGL markets in North America structured today and how do they operate?

•What role will ANS production play in North American gas and NGL markets?

•What market factors are most important to determination of the value of ANS gas and NGL at the point of production?

•What market and economic factors are most important to determination of gas and NGL royalty values under the State's lease agreements with ANS gas producers?

U.S. Natural Gas Market

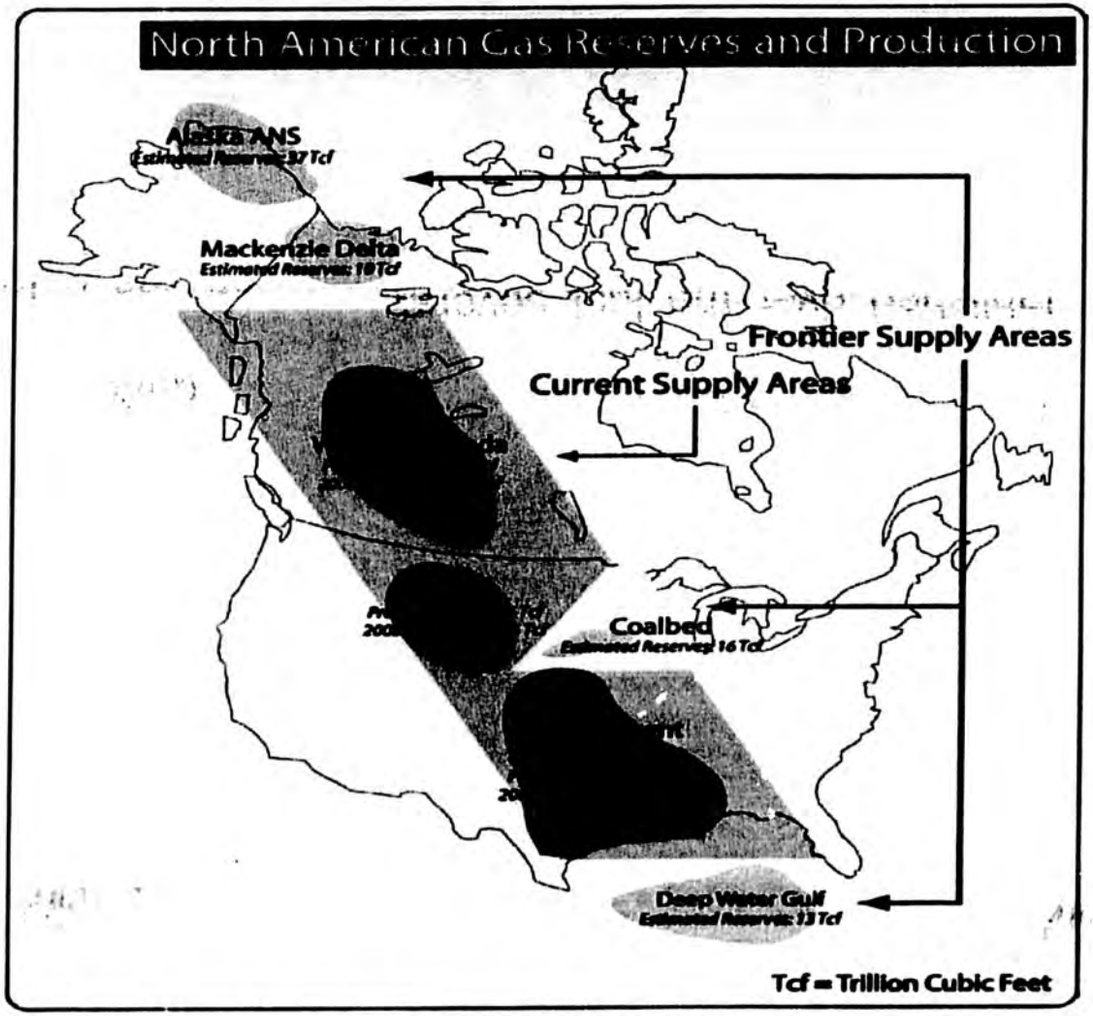
Deregulation of U.S. gas markets over the past 20 years has made them highly flexible and responsive to short-run changes in demand or supply conditions.

- less effective at long term planning for coordinated development of large new supply and infrastructure projects.
- gas prices are sometimes quite volatile.

Gas markets will continue patterns established over the last several years.

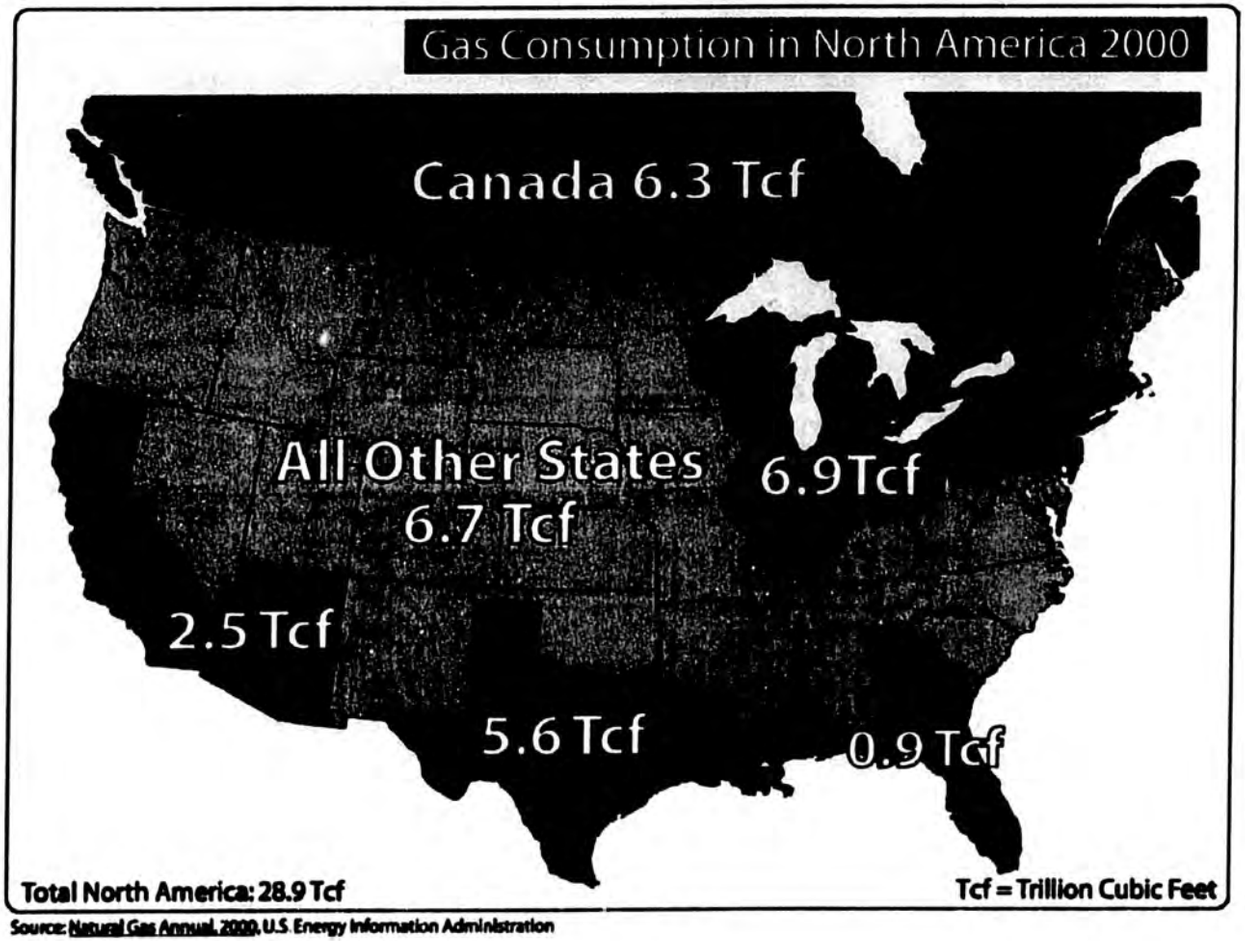
- Short, sometimes dramatic price swings
- Large increments of supply and infrastructure construction may alter price and flow patterns for months or years.

U.S. Natural Gas Supply



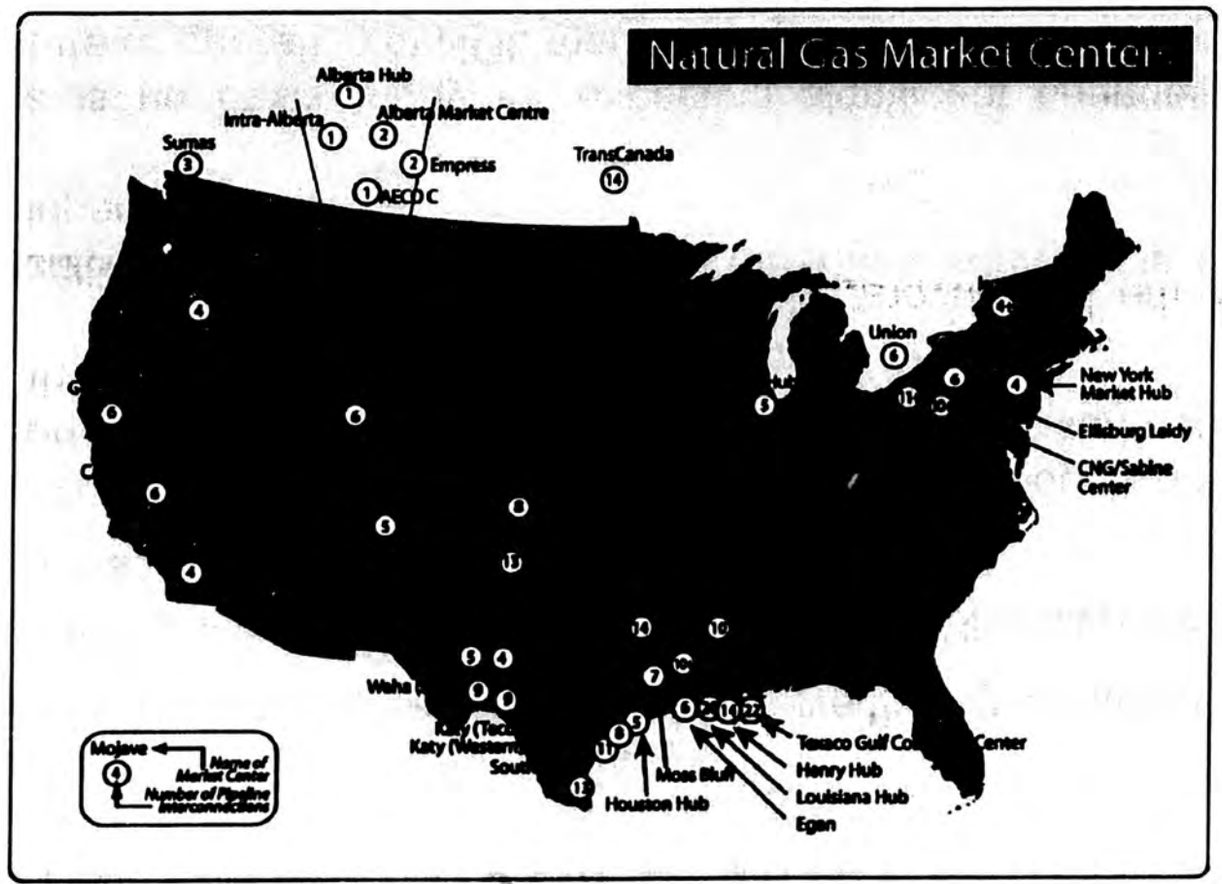
Sources: Potential Supply of Natural Gas in the United States, Potential Gas Committee, 2000.
Natural Gas Potential in Canada, 2001, Canadian Gas Potential Committee.
Natural Gas Monthly, March, 2001, U.S. Energy Information Administration.

U.S. Natural Gas Consumption



Source: Natural Gas Annual, 2000, U.S. Energy Information Administration

U.S. Natural Gas Market Centers



Source: FERC Policy Discussion Paper 99-01 (June 1999).

U.S. Natural Gas Liquids Market

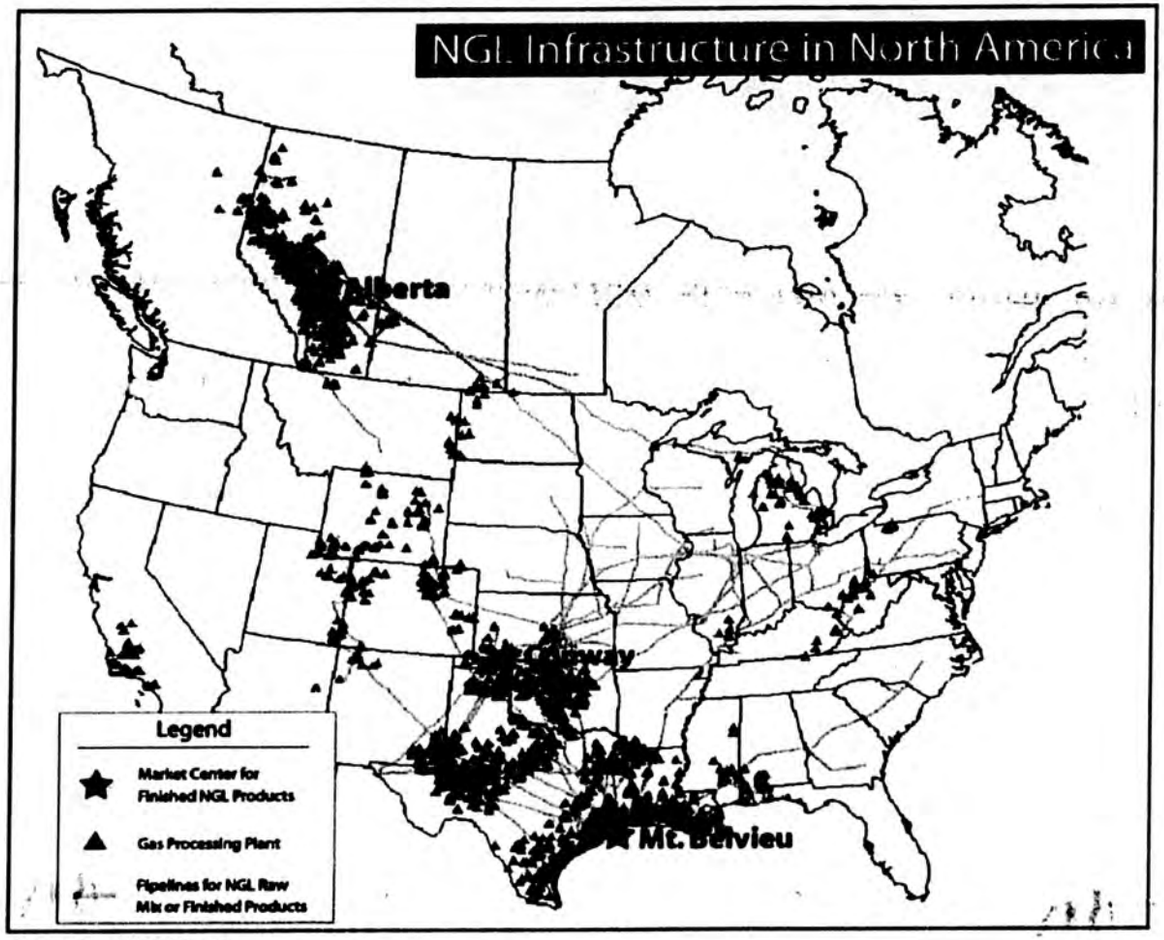
NGL markets are less flexible and responsive than gas markets.

- Only a handful of NGL finished product trading centers, where transaction prices are set and reported.
- Prices paid for raw-mix NGL at the point of production typically are set by deducting transportation and fractionation costs from these downstream market centers.

Information as to market rates paid for these services is not well developed or circulated.

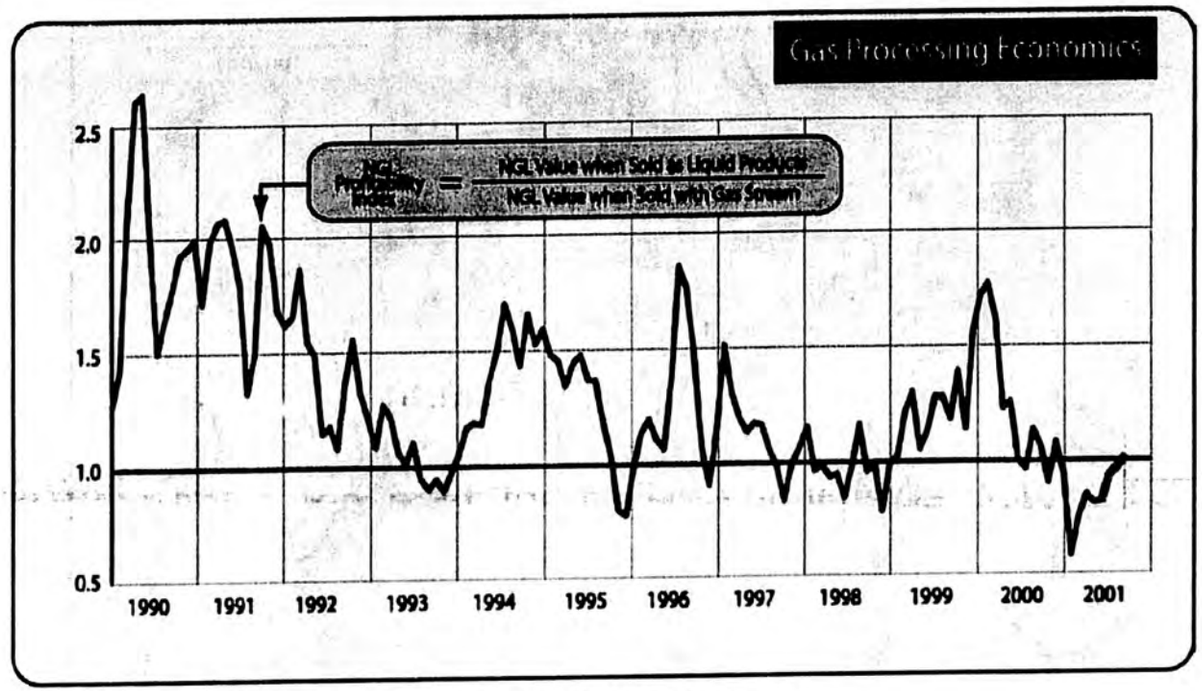
There is no basis today for expecting significant changes in the structure or operation of NGL markets in years to come.

NGL Processing and Market Centers



Source: Penwell MAPSearch.
http://www.mapsearch.com/pipelineFacility.cfm

Profitability of NGL Extraction



Notes: (1) NGL Value When Sold as Liquid Product = Mont Belvieu Composite NGL Price times two, a typical number of NGL Gallons in an Mcf of gas.

(2) NGL Value When Sold With Gas Stream = Henry Hub Price times 25%, a typical heat loss associated with NGL extraction from gas.

Source: Mont Belvieu Composite NGL Price: Gas Processors Report.
Henry Hub, Louisiana: Natural Gas Week.

ANS Natural Gas and NGL

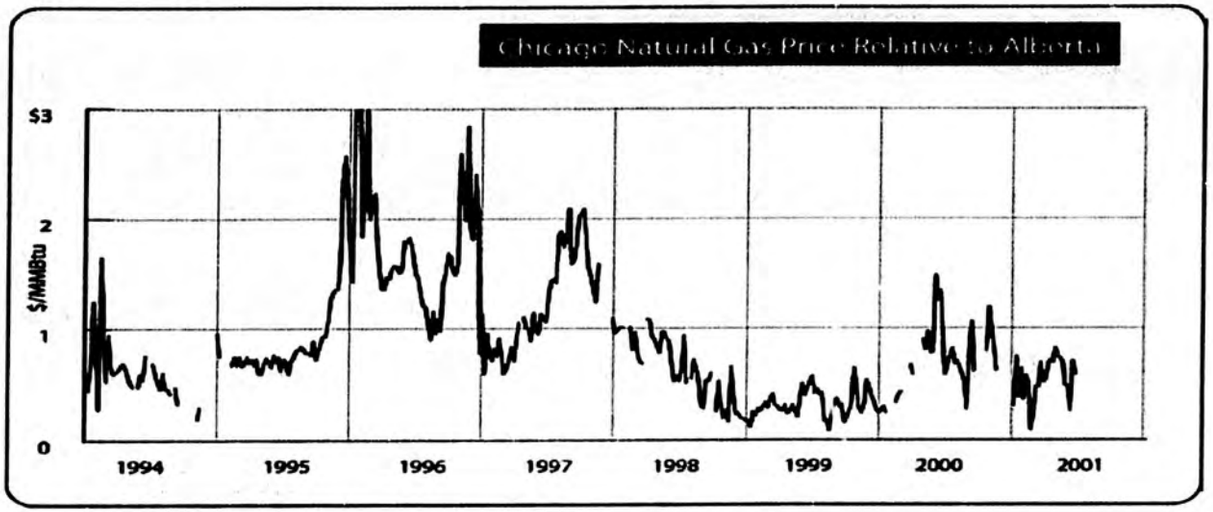
ANS gas and NGL are likely to enter North American markets via Alberta

- As a gas and NGL market center it has experienced wide price swings relative to other market areas.
- A stable and reliable market for gas and NGLs in Alberta will depend on the evolution of production within Alberta and pipeline projects downstream of Alberta.

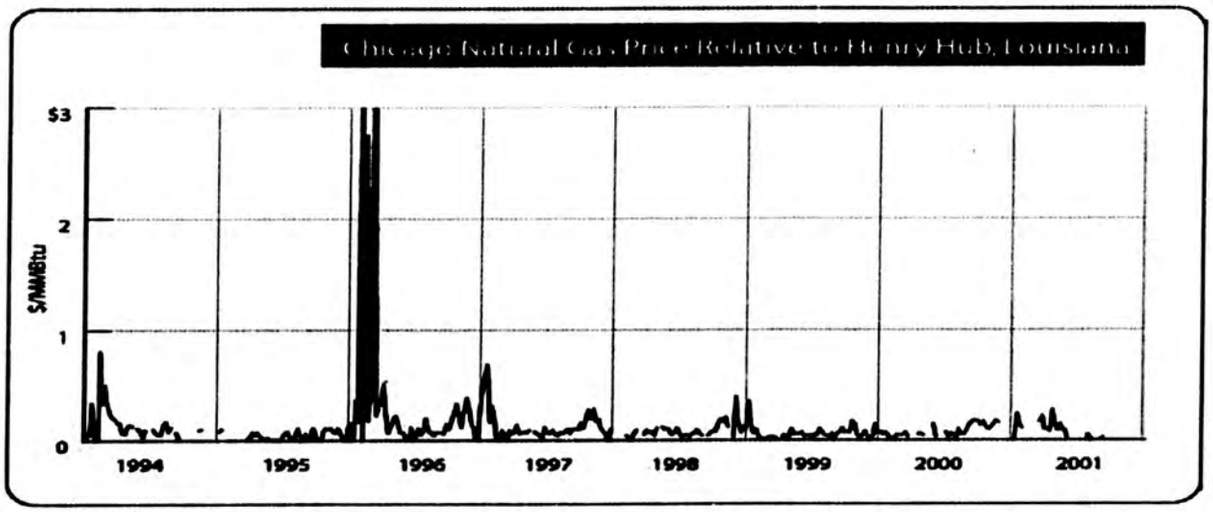
Delivery of ANS gas and NGL in the same pipeline will cost less than transporting them separately.

- Such a pipe, though long and large, will be economically similar to a field gathering system from the perspective of owners and users.
- There is not likely to be a flourishing secondary market for capacity on the ANS pipeline.

Valuation of ANS Gas and NGL



Source: Natural Gas Week.



Source: Natural Gas Week.

Royalty Valuation

Alaska's oil royalty experience provides a useful template for gas and NGL royalty.

- Like ANS crude oil, gas and NGL will be moved to destination markets far downstream.
- The wellhead value of ANS gas will be dependent upon market prices in Alberta and/or other major "nodes" on the North American gas grid and transport costs to those markets.

Royalty is an economic partnership with sharing of product or sharing of revenues.

Royalty Valuation

IT IS CRITICAL THAT PARTNERS SHARE INFORMATION.

During its initial years of production, ANS producers should share with the State information at their disposal concerning movement and sale of ANS gas and NGL.

- This will permit the State and producers jointly to understand how ANS gas is fitting into U.S. markets.
- The State and producers will be positioned to evaluate lower-cost alternative valuation methods that accurately mimic sales proceeds and movement costs.

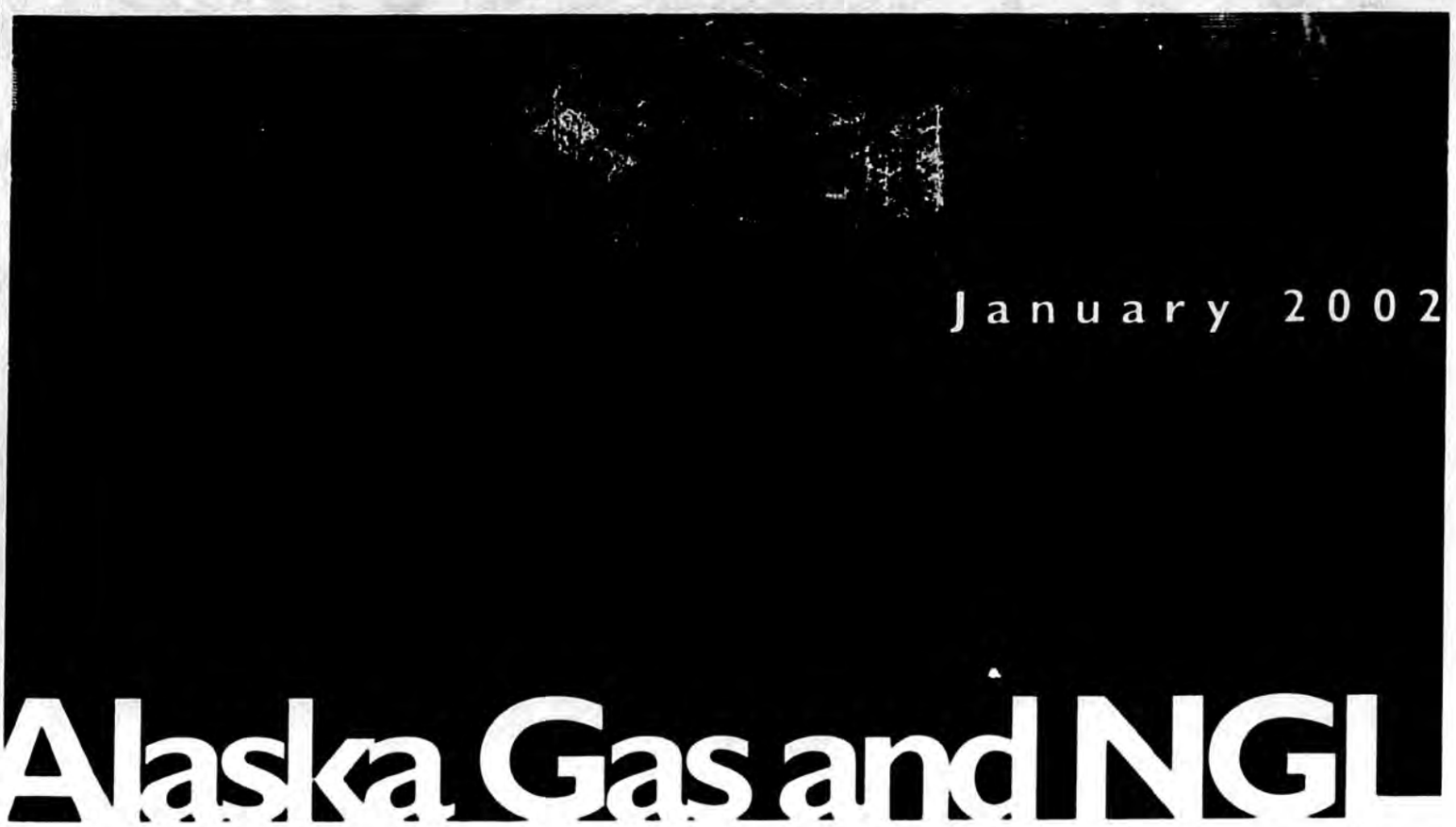
The State should retain its option to take gas and NGL in kind.

Valuation of ANS Gas and NGL

Even the best-conceived royalty valuation formula can go astray over time unless it adapts to new conditions.

ANS oil royalties highlights both the need to maintain flexibility in the procedures and mechanisms used to value and pay gas and NGL royalties

Information as to actual dispositions will be vital both to producers and to the State in understanding how ANS gas and NGL value can be maximized



January 2002

Alaska Gas and NGL

Economic Analysis of Value and Royalty

Report prepared for the
Alaska Department of Natural Resources
Oil and Gas Division

by Roger Ridlehoover and Barry Pulliam

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Purpose and Plan of this Report

It has been known for years that large reserves of natural gas lie under the North Slope of Alaska, but that its location thousands of miles from large gas consuming markets would require relatively high sales prices in those markets to justify development and transportation investments. In the late 1970s gas prices were high and plans for transportation facilities to move ANS gas to Lower 48 markets were pushed almost to construction when price reversals put the project on hold, where it remained until 2000. Since then, a dramatic gas price spike lasting well into 2001 and ongoing concerns that production from Lower 48 reserves cannot serve expected consumption growth in the decades ahead, have returned ANS gas development and transportation facilities to center stage.

The Alaska Department of Natural Resources (DNR) is charged with developing and managing the State's resources for the maximum benefit of all Alaskans. Oil and gas resources fall under the purview of the Department's Division of Oil and Gas. Production from State lands contributes 80 percent of the State's general fund revenues in taxes and royalties. Oil and gas royalties paid to the Department represent over half of the total revenues. Future oil and gas exploration and development will be essential to State government and the growth of the State's economy as revenues from existing oil production decline.

Alaska DNR commissioned this study of the State's gas reserves to address a number of economic issues arising from anticipated production and sale of ANS gas and NGL. In overview, these issues include:

1. How are gas and NGL markets in North America structured today and how do they operate? What principal factors drive prices in those markets?
2. Over its expected production life, what role will ANS production play in North American gas and NGL markets?
3. What market factors are most important to determination of the value of ANS gas and NGL at the point of production?
4. What market and economic factors are most important to determination of gas and NGL royalty values under the State's lease agreements with ANS gas producers?

Chapter Overview

Chapter 1 is a description of natural gas markets in North America as they are structured and operate today. This Chapter also provides historical background as to the evolution of those markets and discusses how gas markets are likely to operate in the decades to come, over the life of ANS gas production.

Chapter 2 presents a similar overview and description for NGL markets in North America.

Chapter 3 discusses economic and market factors that are likely to determine the wellhead value of ANS gas and NGL production when it begins to flow.

Chapter 4 provides a discussion of basic economic aspects of royalty relationships, including description and analysis of typical provisions for valuing natural gas in royalty agreements.

Chapter 5 reviews the State's lease provisions for oil and gas and how those have evolved and operated for oil production.

Chapter 6 presents conclusions and recommendations as to ANS value and royalty issues facing the State and ANS producers.

Report Summary

- Deregulation of U.S. gas markets over the past 20 years has made them highly flexible and responsive to short-run changes in demand or supply conditions, but less effective at long term planning for coordinated development of large new supply and infrastructure projects. As a result, gas prices are sometimes quite volatile. Transportation bottlenecks and surpluses can appear and persist at different points on the continental pipeline grid.
- In the decades to come, gas markets will continue patterns established over the last several years – short, sometimes dramatic price swings in response to temporary conditions, and growth of supply and infrastructure, sometimes in large increments that can alter existing price and flow patterns for months or years before being fully "digested" into the larger grid.
- NGL markets are less flexible and responsive than gas markets. There are but a handful of NGL finished product trading centers, where transaction prices are set and reported. Prices paid for raw-mix NGL at the point of production typically are set by deducting transportation and fractionation costs from these downstream market centers. Information as to market rates paid for these services is not well developed or circulated. There is no basis today for expecting significant changes in the structure or operation of NGL markets in years to come.
- ANS gas and NGL are likely to enter North American markets via Alberta, a gas and NGL center that to date has experienced wide price swings relative to other market areas. While introduction of ANS gas and NGL into Alberta markets may stabilize them, that result depends on the evolution of production growth within Alberta and pipeline projects downstream of Alberta.
- Delivery of ANS gas and NGL in the same pipeline will cost less than transporting them separately. Such a pipe, though long and large, will be economically similar to a field gathering system from the perspective of owners and users. There is not likely to be a flourishing secondary market for capacity, for example, on the ANS pipeline.
- Alaska's oil royalty experience provides a useful template for gas and NGL royalty. Like ANS crude oil, gas and NGL will be moved to destination markets far downstream. The wellhead value of ANS gas will be dependent upon market prices in Alberta and/or other major "nodes" on the North American gas grid and transport costs to those markets.

- Royalty is an economic partnership with sharing of product or sharing of revenues. It is critical that partners share information.
- During its initial years of production, while ANS gas is being introduced into North American markets, ANS producers should share with the State information at their disposal concerning movement and sale of ANS gas and NGL. This will permit the State and producers jointly to understand how ANS gas is fitting into those markets.
- Following this period of intensive information sharing and analysis, the State and producers will be positioned to evaluate lower-cost alternative valuation methods that accurately mimic sales proceeds and movement costs, such as use of published prices in downstream market centers.
- The State should retain its option to take gas and NGL in kind. Doing so preserves its ability to discipline a royalty partner or to avoid neglect or malfeasance.

Note: Throughout this report we use the term "market" in its most general sense, sometimes referring to a geographic area, and sometimes to trading of a particular product, or most generally to commercial activity surrounding a group of related products or services. Economists sometimes use more precise definitions of "market" when analyzing competitive impacts of firm conduct, or price fixing allegations, for example. Because that was not a purpose of this Report, we use the term in its more casual dress.

Chapter I

Gas Markets in North America

Gas markets in North America, defined here as the United States and Canada, are today in the latter stages of an economic and regulatory transition that began more than 20 years ago. That transition, largely but not entirely completed, is from a highly integrated and regulated industry, to one composed of distinct but interlocking segments, some competitive, some oligopolistic, and a few remaining stubbornly subject to monopoly structure and (if left unregulated) exercise of market power. The transition has been slow because legislatures and regulatory bodies are deliberative, and because the physical and contractual infrastructure created under a commercial and regulatory regime that dated back to the early years of the 20th century involved long-term contractual and regulatory commitments that have taken time to revise, play out, or terminate involuntarily.

Over the past decade, gas markets have shown that complete deregulation of gas sales prices and substantial deregulation of gas transportation rates, has been a success if judged by the market's ability to provide reliable service. Markets have responded well to stresses brought about by periods of extreme cold with its attendant heavy gas consumption, and facility outages caused by hurricanes and explosions. No end-users that wanted supply have been without gas. Deregulation has produced not only a market environment in which prices direct supplies to highest valued uses, but major developments in storage, transportation and risk management techniques have given gas producers and consumers alike tools that they never had in regulated markets. Today gas is a favored fuel because of its clean-burning attributes, particularly among electricity generators, and growth in consumption is expected to continue in the years and decades to come.

That situation is a far cry from the outages and curtailments that plagued U.S. markets as recently as the late 1970s. Then it was feared that North America was "running out" of gas supplies. Alaska gas at that time was primed for development but was not in the event called upon. It serves as useful background in understanding the structure and operation of today's gas markets, and as a guide in thinking about current ANS gas and NGL development plans, to trace the major developments in regulation and commercial organization that gas markets have undergone over the past 25 years.

Historical Overview of Gas Deregulation and Market Development

Passage of the Natural Gas Policy Act (NGPA) in 1978 marked the birth of today's gas industry. It mandated time-phased elimination of wellhead gas price controls, setting into motion a regulatory and industry dynamic toward more open, competitive, segmented gas markets that operate today. A fundamental premise of the NGPA was that lifting price ceilings – and ultimately removing them – would bring forth gas supplies that were sorely needed to satisfy growing consumption, and that competition among gas producers could be relied upon to "regulate" wellhead prices thereafter.

In 1985 the Federal Energy Regulatory Commission (FERC) built on this theme, first with Order 436, requiring that U.S. interstate pipelines provide "open access" to their pipeline systems. Before then, pipelines were largely independent systems with relatively few interconnections,

performing all transportation and merchant functions for sales customers – finding, purchasing, and maintaining a gas supply, transporting it, storing it to cover peak demands, and delivering it in accordance with sales contracts and regulations.

With open access, others could buy, move and resell gas supplies using pipeline companies' facilities and, with further regulatory changes, could do so across two or more systems. Though directed to rules affecting pipeline usage and rates, the purpose of Order 436 was to enhance competition in gas commodity markets. The idea was that such markets needed to be more robust both for gas producers and for end-users, with producers able to sell to any potential gas buyer and conversely for gas buyers to be able to reach any potential gas supplier – even those not directly connected to the delivering pipeline. It was reasoned that effective access to all pipelines within the national grid could achieve that objective.

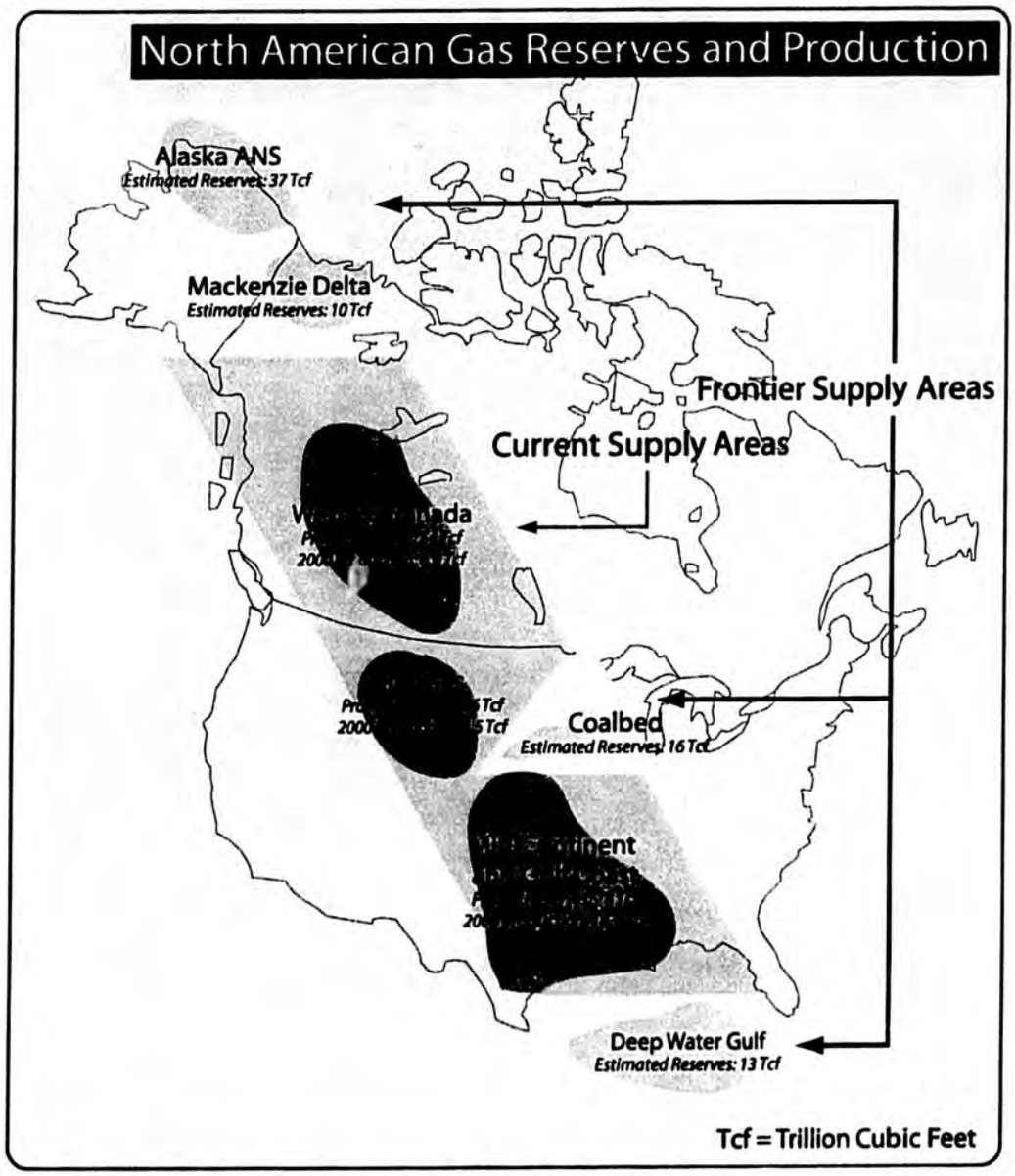
The aims of Order 436 initially proved illusive because pipeline companies retained contractual commitments to suppliers and regulatory obligations to "stand ready" to serve traditional utility customers should independent (non-pipeline) suppliers fail. That put a strain on pipelines and transport customers within the context of shared use of a pipeline facility. So, in 1992, FERC Order 636 relieved that pressure by removing pipeline companies from all merchant functions. Pipeline systems then could be used by all shippers on equal terms, clearing the way for growth of supply, sales, and service markets operating along a transportation grid whose use was neutral with respect to competition in those merchant markets. Order 636 achieved what 436 had attempted – it prompted growth of independent marketing companies and the related industry segments that support gas transactions along the pipeline grid. Gas buyers and sellers could transact with each other irrespective of where either was located.

This regulatory separation, or unbundling, of gas merchant activities from gas transportation service, has brought into clearer focus a distinction in the gas industry between markets for exploration, production, and consumption of the gas commodity itself, and those for the related trading, transportation, financial, and logistical activities that occur between points of production and points of consumption. Transportation and related activities such as gathering, processing and storage have been the subject of regulatory attention in the past decade, and to a large extent the commercial, legal, and regulatory mechanisms and institutions that FERC and state regulators have put in place are stable and can be expected to remain so in years to come, with fine tuning and adjustment as experience and new factors dictate. That part of the industry appears to be settling down after 20 years of perpetual upheaval and change. The focus now is turning from trading and transportation issues toward the serious question of how to find and develop sufficient gas supplies to satisfy growing demand. ANS gas plays a central role in that new focus.

Gas Commodity Markets

Gas reserves in North America lie principally along an axis extending from Alaska and western Canada, through the U.S. Rockies, Texas, and into the Gulf of Mexico (see Figure 1).

Figure 1



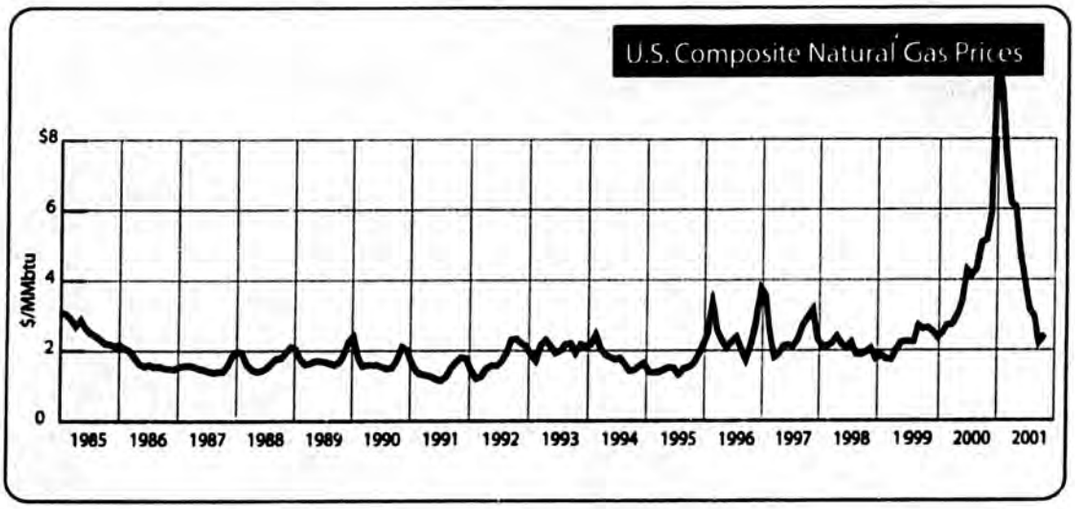
Sources: Potential Supply of Natural Gas in the United States, Potential Gas Committee, 2000.
Natural Gas Potential in Canada, 2001, Canadian Gas Potential Committee.
Natural Gas Monthly, March, 2001, U.S. Energy Information Administration.

More than two-thirds of North American gas is produced along this axis. Historically, gas produced in these areas was purchased by an "anchor" pipeline under a long-term agreement. Pipelines were approved and built if they could demonstrate control, through ownership or contract, of sufficient reserves to serve for many years the requirements of downstream customers that the line proposed to serve. When approved by federal and state regulators, the anchor pipelines took the contracted supplies to consuming markets in the Upper Midwest, Northeast, and West. Gas prices typically were set at regulated levels, with periodic escalations as permitted by regulations. Producers had little marketing responsibility after the long-term agreement was in place.

In the late 1970s, shortages of gas developed in many parts of the United States. Blame was placed at the feet of price ceilings that were too low to elicit exploration and production of new reserves or to give consumers incentive to conserve. In 1978, removal of price controls resulted in increases that had the intended effect on both producers and consumers. Drilling and exploration activity jumped sharply throughout North America. In 1975, 1,800 drilling rigs were operating in North America; by 1981, over 4,200 rigs were in operation, and with predictable results – more gas was found and offered to market. In fact more was offered than consumers would (at the higher prices) accommodate. Gas prices fell sharply in the mid-1980s and stayed low for over a decade as the gas supply "bubble," built up in the early 1980s, stayed stubbornly inflated.

Deregulated sales prices explain only part of the story of gas market development in the 1980s and 1990s. With the advent of open access transportation (1985) and removal of pipeline companies from merchant functions (1992), producer gas sales moved downstream from the wellhead to points of delivery at nearby transmission lines, or even further downstream to points of interconnection among several pipelines and, as confidence grew that trading opportunities would be available when and where they were needed, sales agreements became shorter. The spot market, born in the mid-1980s, provided short-term prices that broadly signaled market conditions both to producers and to consumers.

Figure 2



Source: Natural Gas Week.

In the 1990s, periodic episodes of cold weather, hurricanes, and other short-lived factors generated a few price "spikes," but in general North American consumers enjoyed low gas prices throughout the decade. That prompted steady growth in gas consumption, aided by its reputation as a clean fuel for industrial uses and for electricity generation. But low prices provided weak incentives for producers to find new reserves and at times in the 1990s, they began withdrawing resources not only from ongoing exploration but also from development of existing fields. By April 1999 the North American rig count had fallen to 558.

In Spring 2000, the "quiet" market conditions of the 1990s were abruptly awakened as prices began a steady climb early in the year. A confluence of temporary factors (a pipeline explosion,

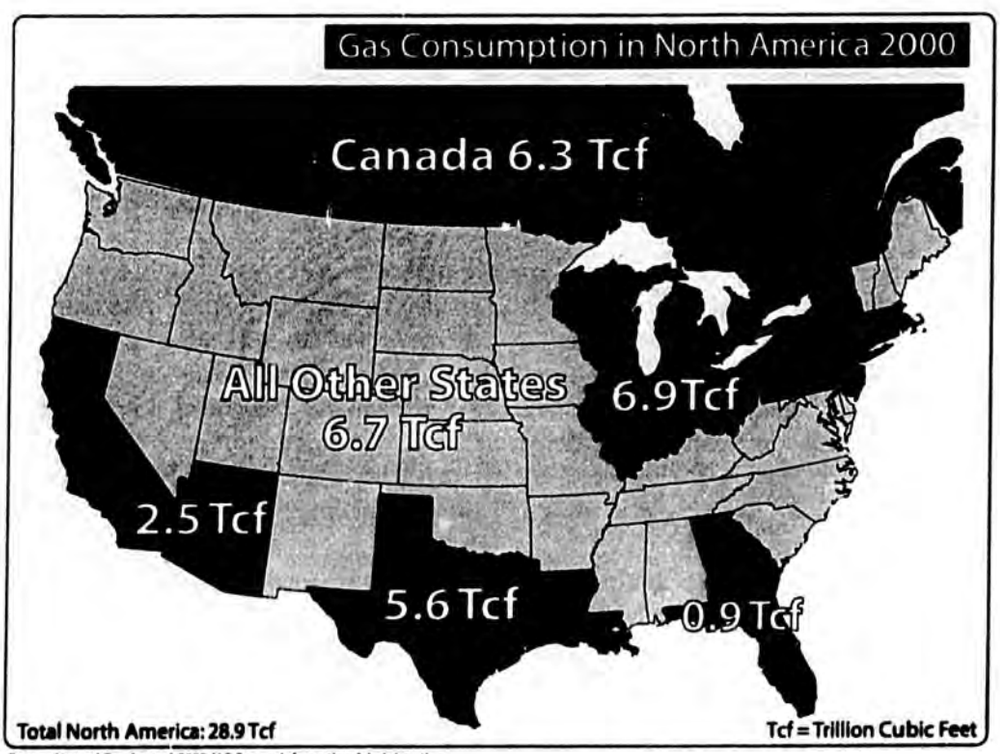
low storage levels), and longer run trends (continuing appetite for gas by electric generators), created a sudden and unanticipated price run-up (see Figure 2). To most, the increase appeared to be more than just another temporary price spike. Throughout 2000 and into early 2001, conventional wisdom became focused on the idea that a new, permanently higher price level had been reached and would be maintained. Yet, from the vantage point of early 2002, both gas production and consumption have again shown themselves to be more responsive to price than conventional wisdom expected. Drilling and exploration activity quickened in 2000 and new supplies began to reach markets in 2001. Higher delivered prices to consumers also caused many to cut back consumption. Plans for new electric generating plants were delayed or canceled. Today, gas prices have returned to levels seen throughout most of the 1990s.

The lesson offered by this history of gas commodity markets and prices is that both production and consumption respond to price changes. As described further below, today they do so quite rapidly, both from the perspective of fluctuations in supply or demand conditions caused by temporary factors such as weather or facility problems, and from the longer-term perspective of continuing development of new supplies to replace depleted wells and provide for growing markets.

Gas Trading, Transportation and Logistics

While gas production in North America is concentrated along a north-south axis centered on Wyoming, apart from Texas and Louisiana, large gas consumption areas lie on an east-west axis from the upper Midwest and Northeastern states to the West and California (see Figure 3). Consequently, a primary task facing the gas industry is getting gas from producing areas to consumers.

Figure 3



Source: Natural Gas Annual 2000, U.S. Energy Information Administration

As noted above, pipeline companies used to perform that function, under the direction of federal and state regulators. They purchased gas at the wellhead, then gathered, treated, processed, compressed, stored, transported, and delivered it to customers. But pipeline companies today provide only transportation service; all other merchant activities are performed by independent companies, or by pipeline affiliates subject to a regulatory mandate of open and non-discriminatory service.

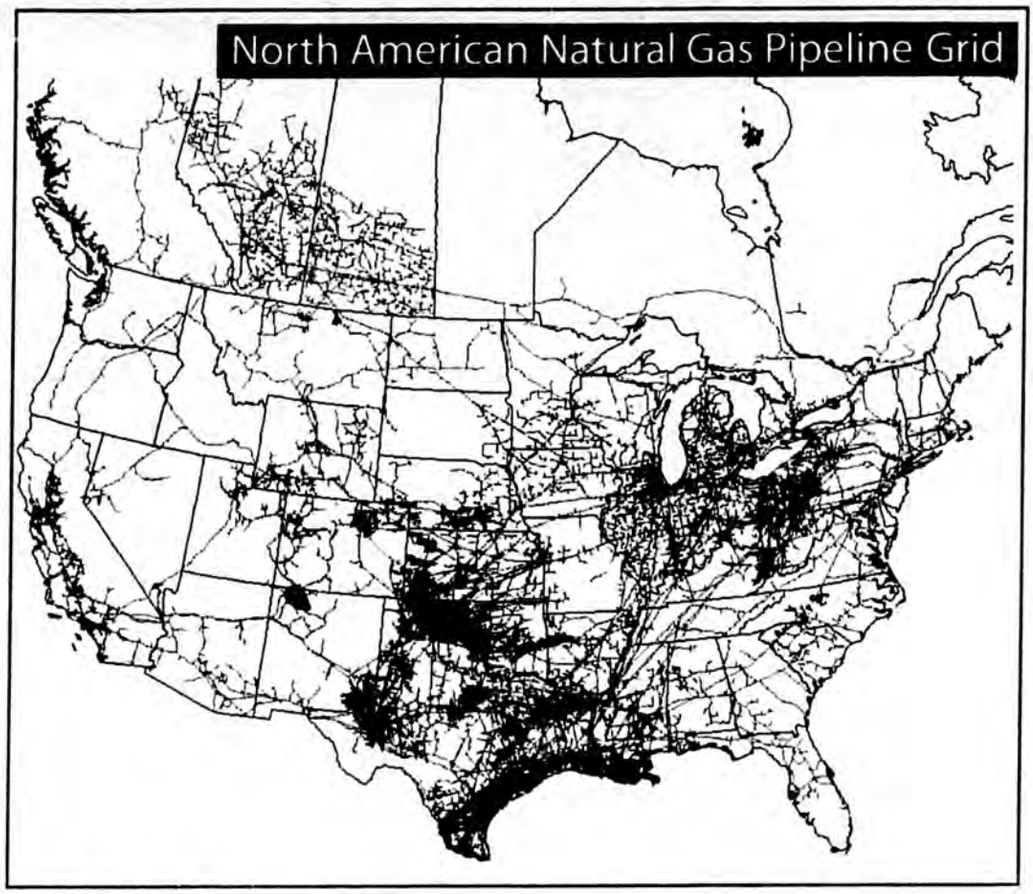
The transition from integrated, bundled pipeline service to today's segmented market has seen the emergence of distinct market segments that provide a host of services along the pipeline grid. These segments operate alongside and in conjunction with gas commodity markets, and include: 1) gathering and processing; 2) pipeline transportation; 3) marketing and trading; 4) market centers or "hubs;" 5) storage; and 6) gas-related financial instruments. Each plays an important role in how the industry operates today, and exerts influence on upstream prices realized by producers and on end-use prices paid by consumers.

Gathering and Processing. Gathering systems are small-diameter pipeline networks of limited geographic scope that act as a bridge from wellheads to the continental pipeline grid. Typically, gathering firms not only move gas from wellhead to grid but also provide services such as compression, dehydration, and gas conditioning to remove impurities and water. Most prominently, though, they also extract natural gas liquids (NGLs) that can be present in the gas stream (see Chapter 2). Traditionally performed by pipeline companies as part of their regulated, bundled service, or by producers as part of the sale of gas production, gathering and processing now are provided also by independent companies under unregulated rates and terms. As greater specialization has taken hold in gathering and NGL processing, agreements have evolved from long-term contracts covering large tracts of developed and undeveloped lands, into shorter, more flexible, and often more geographically compact arrangements. In addition to new commercial forms, competition among gatherers has generated a number of new services, including low-pressure gathering, condensate measurement and marketing, water disposal, and remote flow measurement.

Development of a distinct gathering and processing industry has freed production companies to focus efforts on finding gas, eliminating diversion of resources and management to operations that bear little relationship to knowledge and expertise required for their exploration business.

Long-distance Transportation. Once gathered, treated, compressed and processed, gas is delivered into a transmission pipeline that in turn is part of a continental grid of interconnected pipelines (see Figure 4). That grid is a displacement network, meaning that when gas is injected into the system it is commingled with other supplies that have entered upstream. Buyers withdrawing supplies are not concerned to know the specific (physical) source of the gas because uniform quality standards imposed by all pipelines assure that gas within the grid is fungible. As a result, gas bought by customer B from supplier A may not actually move from A to B; rather, the volume put into the system by A matches the volume removed by B.

Figure 4



Source: Penwell MAPSearch.
http://www.mapsearch.com/pipelineFacility.cfm

The fungibility of gas once it enters the pipeline grid creates opportunity for substantial transportation cost savings compared to a system where specific bundles of product are matched and traced from supplier to customer. FERC Orders 436 and 636 (and most recently, Order 637) were specifically designed to achieve that efficiency by standardizing operating protocols and facilitating contracting across interconnected systems. Gas marketers, producers, and end users can create customized pipeline systems within the existing physical (and separately owned) pipeline systems to "move" gas from hundreds of independent supply sources to a like number of customers. Fungible supplies also greatly facilitate creation and trading of financial instruments tied to gas.

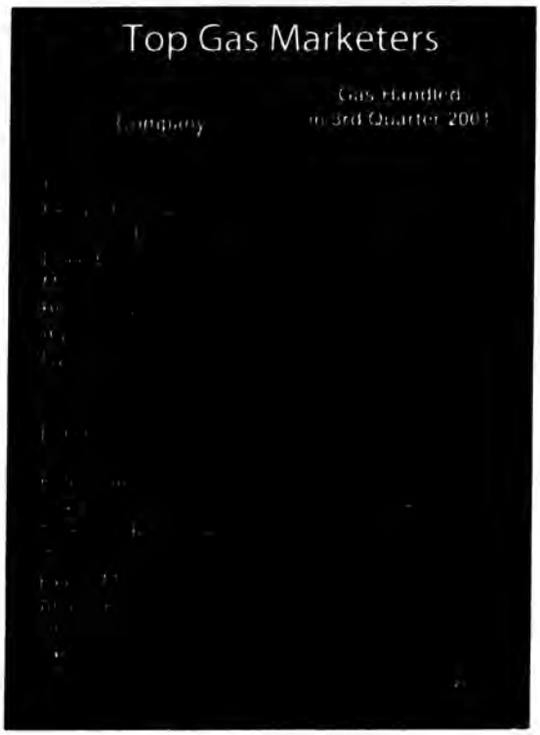
Much of FERC's ongoing work with respect to natural gas relates to removing remaining impediments to efficient use of the pipeline grid. In crafting rules designed to do that, FERC is mindful of the dilemma it faces concerning short-run efficiency versus long-run efficiency. In its official pronouncements, and in speeches given by commissioners, it appears that FERC is striving to attain both; that is, it is trying to create a pipeline market where short-run price signals effectively ration available capacity and provide appropriate long-run incentives for investments in new systems and expansion of existing ones.

Marketing and Trading. If there is one party that straddles all aspects of the gas industry, it is the gas marketing company. These firms obtain access through ownership and/or contract to

facilities needed to: a) assemble a portfolio of gas supplies; b) hold and repackage them as necessary; and c) make deliveries to a portfolio of gas customers. Competition among marketers (entry into the industry is relatively easy), coupled with opportunity to earn unregulated profits has created intense pressure on them to create innovative services and to minimize costs. That competition confers a tremendous economic benefit both to gas producers and to consumers.

Marketing firms have come to the business from a variety of paths. Some were created out of pipeline companies, some from producers, and some from gas distribution companies. Marketers handle more than 80 percent of gas consumed in North America.

Figure 5



Gas marketers' activities serve to link gas and other energy product markets, particularly electricity. These linkages have had a number of impacts on operation and development of the gas business:

Cross-commodity risk management

Short-term gas purchase agreements (weekly, daily, even hourly) and associated short-term transportation capacity agreements.

Short-term storage agreements

Greater summer demand by electric load that smoothes the gas industries' traditional winter peak

Siting of new electric generating plants along pipeline routes or near gas market hubs.

The emergence of marketing firms also has spurred growth and innovation in activities related to marketing. For example, marketers' need for information has created a robust industry of firms that collect, interpret, analyze, and distribute information of relevance and importance to gas buyers and sellers, including information about weather, prices of gas and other fuels, transactions, demand patterns, storage flows and levels, and much more. Government agencies, private firms and quasi-public organizations such as trade associations and industry groups also contribute to regulatory hearings, conferences, trade shows, and other public forums that spread information among market participants.

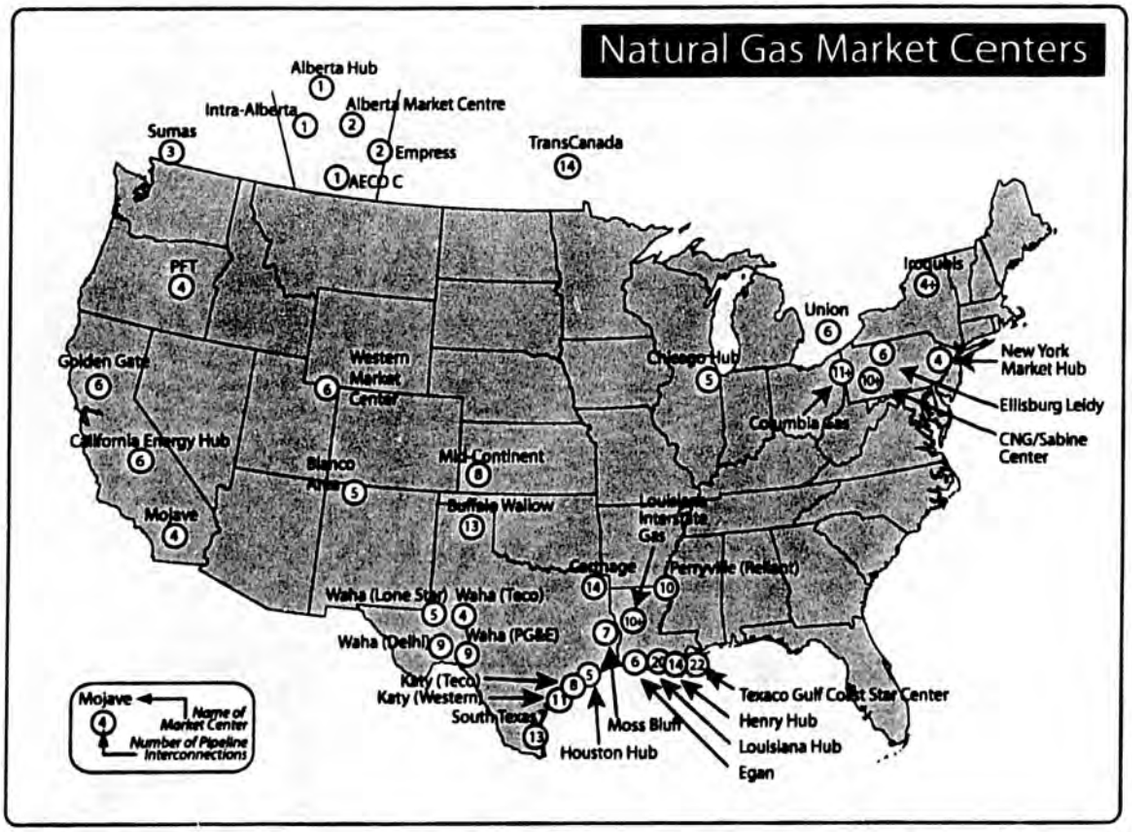
Some of these organizations are active in making contracting and exchange less costly by writing and endorsing standardized sales, storage, and transportation agreements. The Gas Industry Standards Board (GISB), for example, is a quasi-public organization composed of representatives from several segments of the industry. Though GISB is the focal point for this effort, private companies participate as well when, for example, they create and offer electronic trading services using standardized agreements. Some of these trading platforms simply provide low-

cost means for buyers and sellers to effect trades they already have arranged, but others provide a market-making function of internally matching buyers and sellers so that both can transact anonymously and cheaply.

E-commerce in the gas industry, though still relatively new, is advancing quickly. It is expected that all trading of gas, pipeline capacity, and storage will occur at a computer screen rather than by phone and fax (financial instruments already are so traded). That will make the industry even more responsive to short-run changes in market conditions.

Market Centers (pipeline "hubs"). Market centers are places along the pipeline grid where marketers and others aggregate supplies prior to transshipment to downstream customers. There are 38 market centers across North America, with six more in various stages of development. In general, such hubs lie near the intersection of two or more pipelines.

Figure 6



Source: FERC Policy Discussion Paper 99-01 (June 1999).

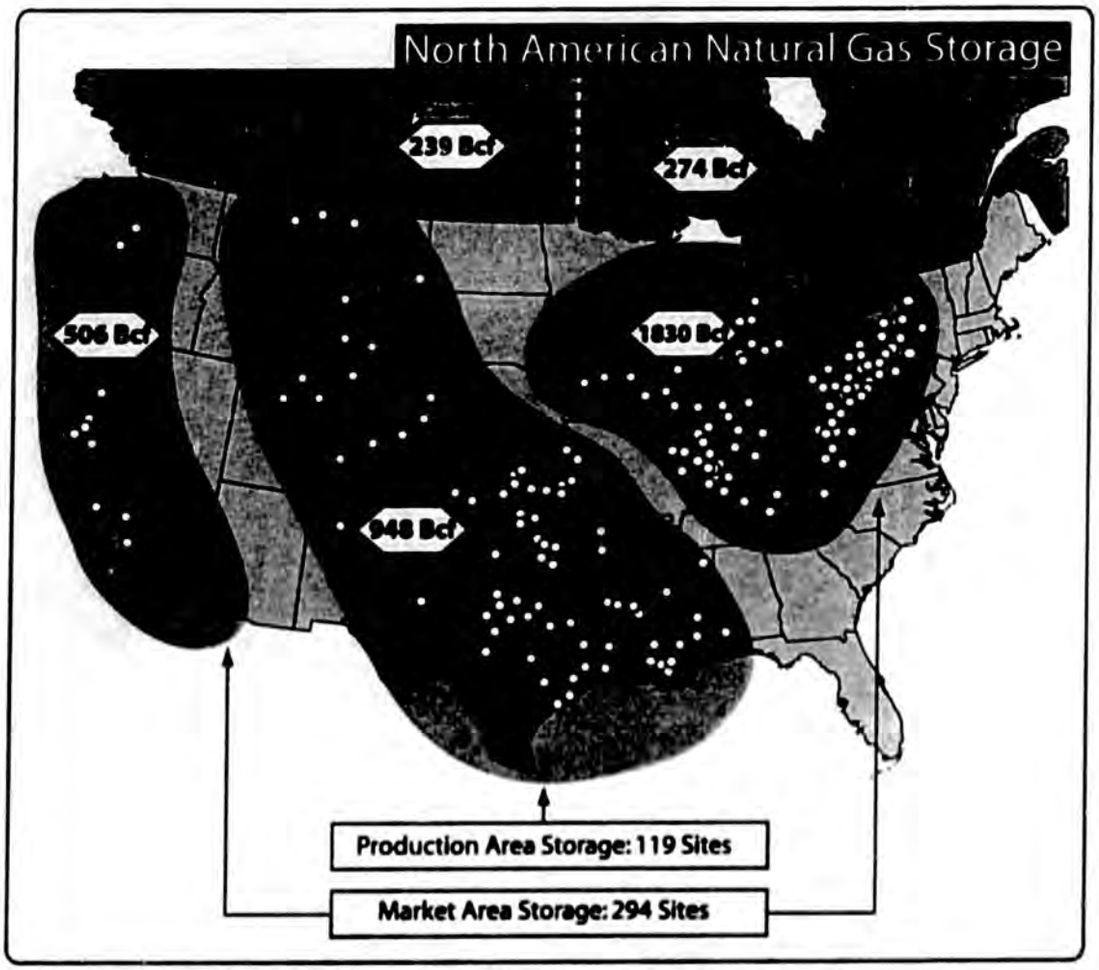
Hub management involves operation of physical facilities such as pipes, valves, storage, and compression, and provision of ancillary services that are useful to marketers, producers and other customers, such as electronic trading, "wheeling" gas from one pipeline system to another, short-term gas storage ("parking"), short-term lending or borrowing of gas among traders, long-term storage, or other forms of transaction support.

FERC recognized that pivot points along the grid would be an important element in creating responsive gas markets. To that end, it forbade pipelines that connect to hubs from taking any

actions that could distort or discourage use of them. The result has been steady and substantial growth both in the number of hubs operating and in the services offered. Today, there are production-area hubs, where upstream supplies congregate awaiting dispatch to distant markets, and market-area hubs, where supplies are "staged," awaiting delivery to nearby end-use customers. Many local distribution companies (large buyers of gas) have come to rely heavily on nearby market-area hubs as a supply source. That relieves their burden of locating supplies and arranging long-distance delivery. That these kinds of customers, who bear a legal obligation not to run out of gas supply, consider market-area hubs to be reliable sources illustrates their importance in today's gas industry.

Storage. Gas storage facilities often are associated with market hubs, though many exist apart from them. There are three types of storage facilities: aquifers, depleted gas fields, and salt domes. Depleted gas fields and aquifers can provide a large volume of storage capacity, but typically exhibit slow injection and withdrawal speed. Salt domes are smaller, but can take in and release stored gas more quickly. That attribute is especially important for storage facilities near consuming markets, where weather can trigger large pulls on stored gas, or at hubs, where temporary excess supplies can be inserted into storage and removed a short time later.

Figure 7



Source: U.S. Energy Information Administration, Form EIA-191, "Monthly Underground Gas Storage Report."
Canadian Gas Association storage survey - November 30, as reported in Gas Daily, December 10, 2001
American Gas Association storage survey - November 9, as reported in Gas Daily, November 10, 2001

The number and kind of services offered in connection with storage have grown and become more innovative. Storage once was a tool used only by local distribution companies to provide peak winter deliveries, but now it is used by producers, marketers, large end users, and local distribution companies, for a variety of reasons, including daily balancing, risk management, and trading.

Financial Instruments. In addition to creating geographically diverse portfolios of supplies and customers, marketers and others also hold supply and delivery positions that span time. To aid management of price risk inherent in such inter-temporal obligations, these parties have turned to financial markets for risk-hedging and trading instruments. The natural gas futures contract created by NYMEX in 1990 became the fastest growing contract, in terms of volume traded, in that exchange's history. Futures contracts, forward contracts, options, swaps, and other financial instruments related to gas, NGL, and allied products are traded on organized public exchanges, and via private exchanges such as Intercontinental Exchange (ICE) and those operated by large marketers such as Dynegy. A principal use of these financial instruments is risk management. Marketers, producers, and customers can, at low cost, "lock in" prices using them. The ability to do so aids financial planning, reduces capital cost, and permits more efficient use of physical assets.

The new features of gas logistics that have grown up over the past 10 years – marketing companies, open access transport, hubs, storage, and financial instruments – all serve to make gas markets highly responsive to short-run changes in supply or demand conditions. Gas sales, transportation, and storage agreements today are shorter than those in the integrated, regulated industry because most buyers and sellers have confidence that trading partners will be available when and where they are needed. Transportation rates, storage rates, and even gathering and processing rates all can change relatively quickly. As a result, gas prices at a specific market location can be quite volatile, as can price differences between locations. While that serves to discipline markets and efficiently allocate existing supplies and facilities to their highest valued uses, it can weaken or distort long-term price signals for investments.

The enhanced short-run efficiency of the gas industry is therefore a mixed advance to the integrated, regulated industry of years past. With today's disaggregated industry, short-run prices are responsive, but long-range planning is harder. In the past, the process of regulatory approval for pipeline projects imposed an organizing mechanism that effectively coordinated simultaneous development of pipelines and supplies. That mechanism no longer operates, and today pipelines and supplies can be built and developed on different schedules, sometimes leaving one without the (properly-sized) support of the other. Examples abound. Development of U.S. Rockies gas over the past decade or more provides numerous instances of excess pipeline capacity (when a new project is completed), followed by excess gas supplies (as new fields are found or developed). The San Juan Basin and Gulf of Mexico are other examples.

The economic effect of independent development of supply and infrastructure is that the continental grid works less efficiently than it otherwise might, with some sections suffering over-capacity (and low transport rates) while others are full (and enjoy high transport rates).

North American Gas Markets over the Next Several Decades

Over the past two decades, the regulatory focus has been on facilitating development of gas commodity markets by, ironically, reforming pipeline rates and access rules. The success of that program has changed dramatically the way gas is bought and sold, and how pipelines and storage facilities are utilized. Now market institutions such as electronic trading, futures contracts, risk management techniques, hubs, storage, and others are firmly established and can be expected to remain in place. Economic forces now shaping the industry include a rate of demand growth that threatens to outpace development of new gas reserves; fine tuning of pipeline regulation by FERC; adoption of standardized trading instruments and electronic trading methods; and continuing expansions and extensions of the pipeline network and related facilities such as storage and hubs.

Over the next several decades, the marketing and logistic aspects of the gas industry will continue to undergo refinement and adjustment, but the industry's main focus will likely return to the serious problem of finding enough gas reserves to satisfy growing consumption, especially that associated with electricity generation, and integrating them into new and existing physical systems and market trading patterns. Management of that two-fold process of supply and infrastructure development is likely to remain fractured and accordingly, the industry will continue to find at any point in time that its transport grid has sections with excess capacity, and others that are severely constrained.

Consensus projections call for North American gas consumption to exceed 35 Tcf by 2020. Figure 1 above shows that in order to satisfy that demand over the next several decades, the existing gas production axis will need to be extended at both its northern and southern ends. ANS gas will be a key component. How ANS gas will fit into the Northern American market, and how it is likely to be valued there are discussed in Chapter 3.

Chapter 2

NGL Markets in North America

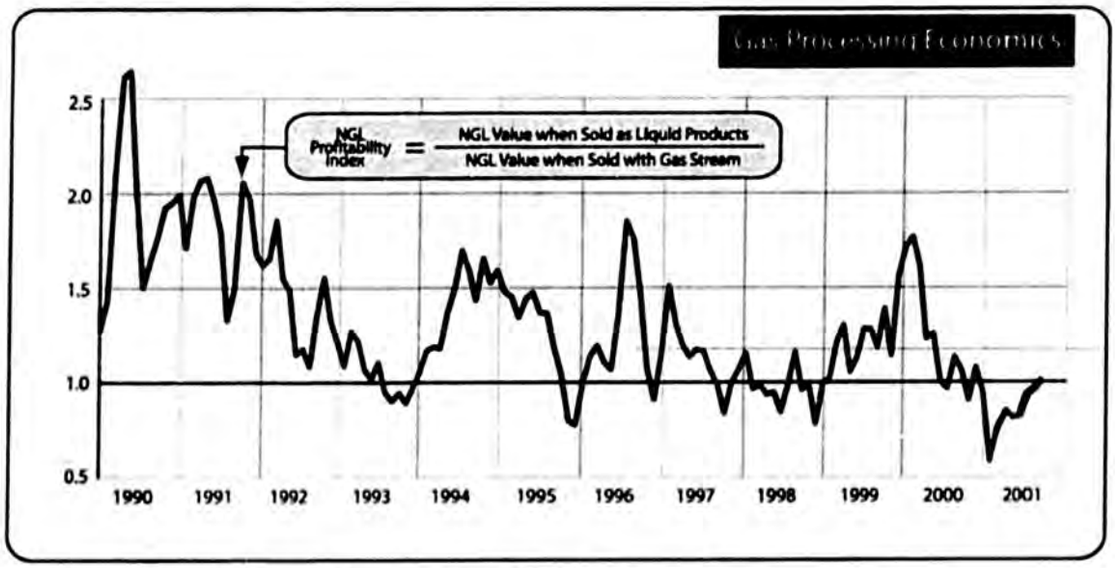
Natural gas liquids (NGL) are by-products of natural gas, carried to the surface by the gas stream itself. The hydrocarbon liquid produced with natural gas is a mixture of ethane, propane, butane, pentane, and more complex hydrocarbon molecules. It can be, and in some producing areas, must be, extracted from the gas stream and sold as a separate product. NGL markets, though linked to natural gas, are different in organization and operation.

Extracting finished NGL products from a gas stream is a two-step process. The first – called gas processing – typically occurs at a plant located near gas wells, where a "raw mix" of liquids is removed from the gas stream. That liquid mix then is piped or trucked to one of several fractionation centers in North America, where – step two – finished products ethane, propane, butane, and others are separated and sold.

Whether NGL extraction adds value to a particular gas stream depends on how much NGL is present and on the prevailing relationship between NGL prices and natural gas prices. Extraction adds value when revenue from NGL sales exceeds extraction, fractionation and transport costs and the opportunity cost of leaving the NGL in the gas stream and selling them along with the gas (methane). That opportunity cost arises because gas with liquids contains more heat than gas without liquids and therefore is more valuable.

These factors – gas prices, NGL prices, and costs – fluctuate on a daily basis, and often quite dramatically, so the profitability of gas processing is uncertain and difficult for any gas producer to predict.

Figure 8



Notes: (1) NGL Value When Sold as Liquid Product = Mont Belvieu Composite NGL Price times two, a typical number of NGL Gallons in an Mcf of gas.

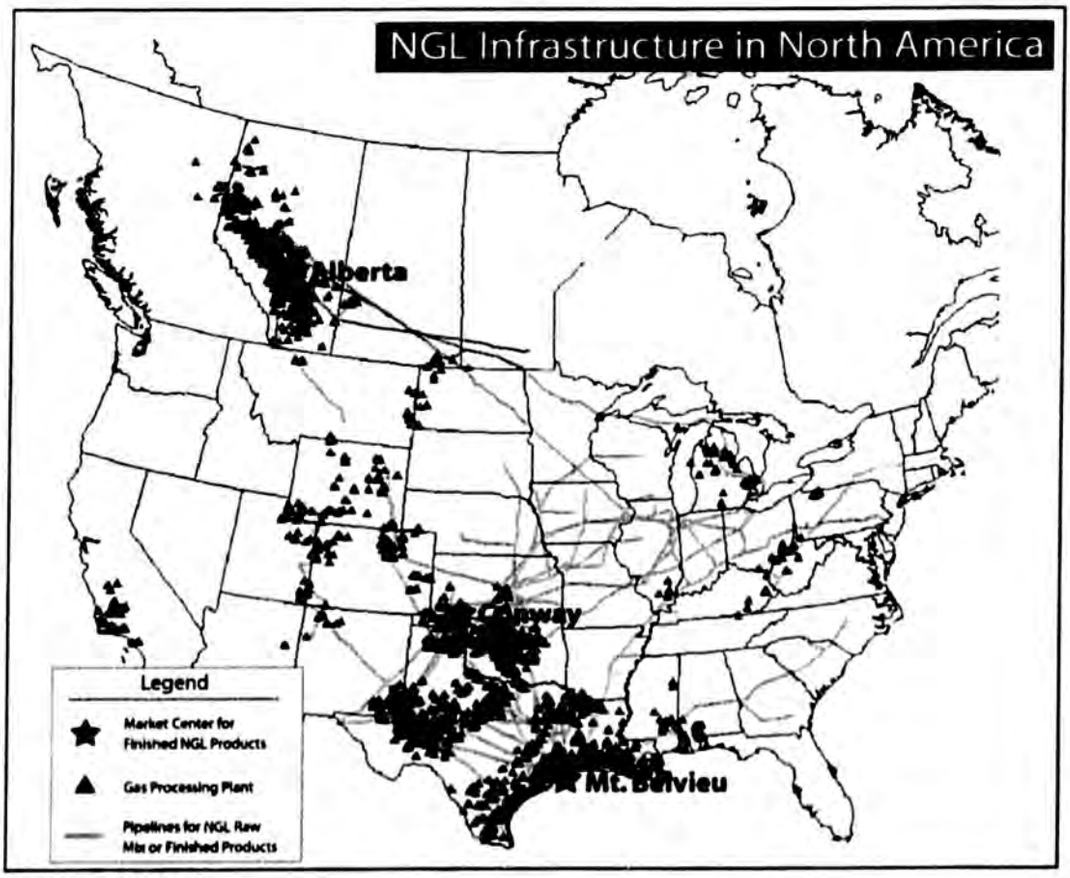
(2) NGL Value When Sold With Gas Stream = Henry Hub Price times 25%, a typical heat loss associated with NGL extraction from gas.

Source: Mont Belvieu Composite NGL Price: Gas Processors Report.
Henry Hub, Louisiana: Natural Gas Week.

Figure 8 shows a measure of the profitability of NGL extraction. The index shown is simply the ratio of the dollar value of gas when its NGL is extracted and sold separately, compared to the dollar value of that same gas if sold without removing NGL. When the ratio is greater than 1.0, NGL processing can be favorable to a gas producer (depending on plant costs); when the ratio is less than 1.0, NGL processing is not profitable. On average, the upgrade associated with NGL extraction (using the assumptions of Figure 8) is eight percent. That is, the value of NGLs extracted over the period shown was eight percent higher than the value of gas lost in the extraction process. That implies an added value from processing of 12 cents per mcf (thousand cubic feet) before payments to processing plant owners. As the Figure indicates, while gas processing is most often profitable, it is sometimes unprofitable and the economics are volatile.

Against the background of this uncertainty, the NGL industry also must cope with the problem that many of the facilities needed for processing – extraction plants, storage, pipelines, and fractionation facilities – entail large, sunk investments. Accordingly, it is not feasible to move resources quickly into or out of gas processing in response to short-term fluctuations in prices or profits. These two facts – fluctuating and uncertain profitability, and sunk capital – drive much of the operation, contracting, pricing and economic organization of NGL markets.

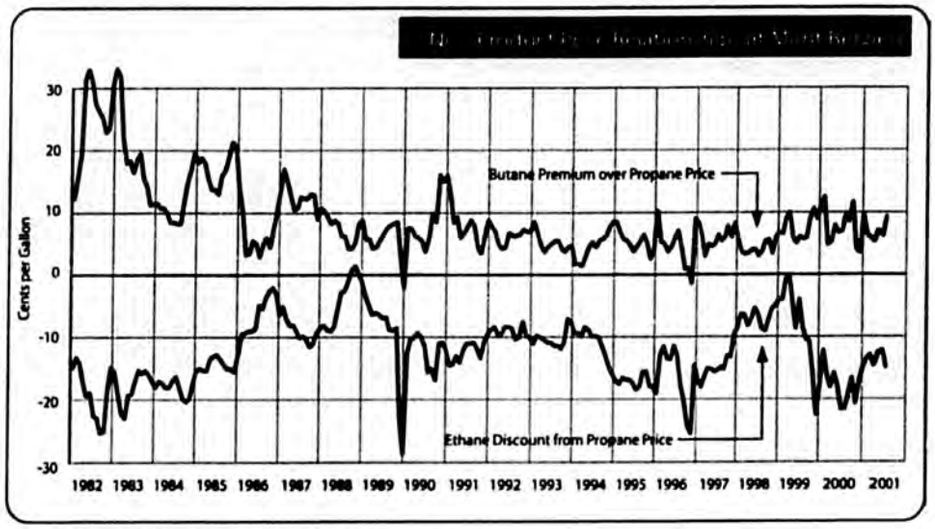
Figure 9



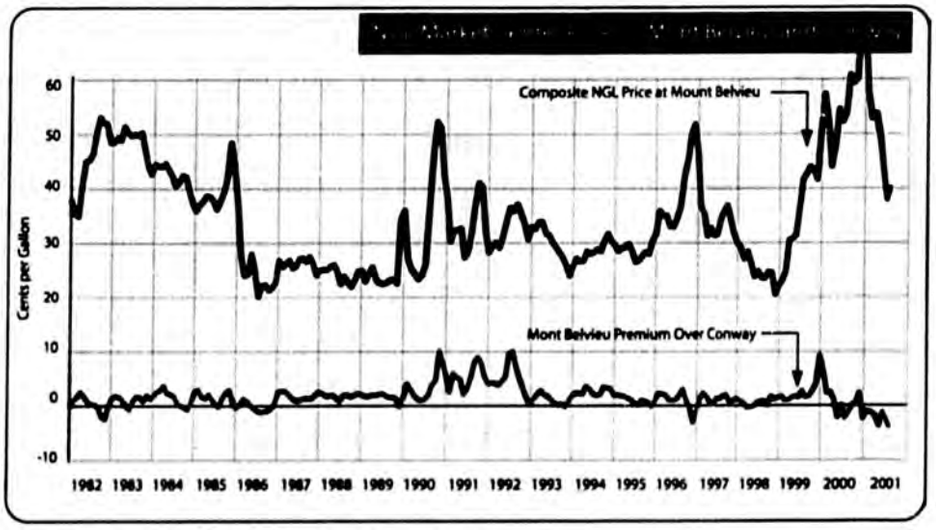
Source: Penwell MAPSearch.
http://www.mapsearch.com/pipelineFacility.cfm

Figure 9 shows the geographic distribution of NGL processing plants, pipelines and fractionation centers in North America. Fractionation centers generally are located near petrochemical plants (major customers of NGL finished products). Mont Belvieu, Texas; Conway, Kansas; and Alberta, Canada are three of the largest such centers. These also are where sales markets for NGL finished products are most active and, therefore, where arms-length transaction prices are established and widely quoted through publications and information services. The price of each finished product is subject to distinct market forces. While these prices move in sympathy, they do not always move in lockstep. The same finished product sold at different market centers can trade at substantially different prices. This web of product and price dynamics adds considerable complexity to NGL markets that is not present in gas markets. Examples of these price patterns and relationships are illustrated below in Figure 10.

Figure 10



Source: Ethane: 1982: Butane – Propane News; 1983-2001: Gas Processor's Report.
Others: 1982: Platt's Oilgram Price Report; 1983-2001: Gas Processor's Report.



Source: Ethane: 1982: Butane – Propane News; 1983-2001: Gas Processor's Report.
Others: 1982: Platt's Oilgram Price Report; 1983-2001: Gas Processor's Report.

Processing Agreements

Producers of NGL-bearing gas usually enter into a contractual agreement with a nearby processing plant to remove raw-mix NGL. These agreements allocate the costs, benefits, and risks of processing.

1. *Keep-Whole Agreements.* Here the gas producer allows the processing plant owner to extract and sell NGL present in the gas. In return, the producer receives a quantity of MMbtu's, in the form of gas, equivalent to the heat content of the extracted liquids. Thus, the gas producer is "kept whole" for the loss of heat that results from removal of NGL from his gas stream.

2. *Percent of Proceeds Agreements.* Under this arrangement, the gas producer and processing company split proceeds of NGL sales, with the producer usually retaining 70 percent or more. Normally, the producer bears the cost of fuel consumed in operating the processing plant, and the cost of heat "shrinkage" associated with removal of NGL-related MMbtu's from the raw gas stream.

3. *Fee for Service Agreement.* Under this arrangement the gas producer simply pays a fee to the processing company for its service, bears all the opportunity cost associated with plant fuel and shrink, and sells for its own account all the NGL that is extracted.

Variations within each type affect the cost-, benefit-, and risk-sharing characteristics of each, but in general keep-whole arrangements allocate cost, risk, and reward to the processing company; fee-for-service arrangements allocate cost, risk and reward to the gas producer; and percent-of-proceeds arrangements allocate some cost, some risk, and some reward to both.

Downstream Finished Product Prices Determine Upstream Raw-Mix Values

Processing plants are located in gas producing areas and most are far removed from fractionation centers and finished-product sales markets (see Figure 9). There are over 1,500 processing plants sprinkled throughout the gas production belt that extends from western Canada to the Gulf of Mexico. By contrast there are 86 fractionation plants, with over half of total fractionation capacity located in the Houston, Texas area, Conway, Kansas, and Alberta, Canada.

Because little or no active market trading occurs at most upstream processing plants, the value of raw mix NGL produced at them depends upon the plant's location relative to one of the large NGL fractionation and finished product sales markets. Upstream NGL prices typically are set equal to published prices for finished products sold at Mont Belvieu, Texas or Conway, Kansas less deductions for transportation of the raw-mix NGL and fractionation costs. That formulation sounds simple, but in practice it can be a complex derivation of value, owing mostly to the difficulty of obtaining information concerning cost deductions.

Gas producers, with operations upstream even of processing plants, can readily obtain published information as to finished product prices at downstream market centers, but often they have little or no information about transportation and fractionation costs incurred to move their raw mix NGL from a nearby plant to those markets. Plant owners, who must bear those costs, have direct access to them. As a consequence of this information asymmetry, intentional or inadvertent distortion of deductions can be used to lower the value paid to producers (or

equivalently, to raise processing plant charges). At a minimum, the asymmetry presents an ever-present negotiating tension between producers and plant owners.

This wellhead NGL valuation difficulty is a persistent problem for gas producers and allied claimants (royalty owners, taxing authorities) for a number of reasons:

1. The transportation grid for NGL is not comparable to the gas grid – It is smaller, with fewer interconnections, fewer market centers and, for the most part, it is not a displacement network. See Figure 4 in Chapter I and compare it to Figure 9 above.

2. There are far fewer marketers buying and selling NGL than for gas.

3. NGL finished product customers tend to be clustered around the major fractionation and market centers. This leads to active trading at these market centers, but little outside of them.

4. Accumulation and dissemination of information concerning prices and the cost of services such as transportation and fractionation is much less than exists for gas markets.

In short, NGL buyers and sellers work with less public information and fewer trading tools than those in gas markets. There is little or no publicly-available price information, for example, regarding prices paid for NGL at upstream locations away from the major NGL market centers. Upstream NGL values that are derived or estimated solely from public information may only approximate what actual transaction prices might be if upstream market activity was widely reported.

There are other attributes of the NGL industry that distinguish it from natural gas. For example, contracting and exchange in NGL markets is not highly standardized and still involves significant cost of negotiating and monitoring agreements. Agreements tend to be longer than is typical for gas sales. Both input costs and product prices are subject to economic forces in related markets (natural gas, petrochemicals, gasoline refining). And, an imbalance of knowledge and information exists among those in the industry. In short, NGL markets in North America are far less "commoditized" than those for gas.

North American NGL Markets Over the Next Several Decades

Like gas markets, NGL markets are likely to operate in the future much as they do today, but for different reasons. The gas industry has moved a long way toward commoditizing not only gas, but related services such as transportation, storage and financial instruments. This makes those markets accessible to a wide variety of participants. While some NGL finished products may be considered commodities, the ease of market exchange is far less than it is for gas. That is not likely to change in the foreseeable future. NGL markets will remain the domain of specialists. There will continue to be a relatively small number of NGL market centers in North America where prices are determined by trading among a relatively small number of buyers and sellers. That limits the amount of information upon which to base value estimates outside these market centers. And finally, there is no regulatory force at work now to push NGL markets in any discernible new direction. Though every market undergoes change over time, there is no basis today for predicting that NGL markets will change.

Chapter 3

Valuation of ANS Gas and NGL

Current gas consumption in North America is about 70 billion cubic feet (Bcf) per day. Consensus growth projections, if realized, would put consumption at 85-90 Bcf per day by 2010. Current NGL consumption in North America is about 120 million gallons per day. Assuming continued NGL extraction rates, projected NGL production for 2010 would be 154 million gallons per day. A developed and flowing ANS supply of 4 Bcf per day of gas and 10 million gallons per day of NGL would account then for about 5 percent of total North American gas sales and 7 percent of NGL sales.

The value of Alaska gas and NGL when it begins production will depend upon prices and market conditions in North America, not in-state markets. Local markets cannot absorb the large volume of gas produced from ANS fields, even at very low prices. The bulk of ANS gas and NGL will flow to markets in North America and accordingly, analysis of valuation must focus on its anticipated role in those established markets. A few key factors will determine that role: the pace of North American demand growth; the ability of existing producing areas to maintain or increase output; the size, development cost, and accessibility of frontier supply areas other than Alaska; and the specific intermediate and destination markets within North America to which ANS gas and NGL are most likely to be routed.

North American Demand Growth

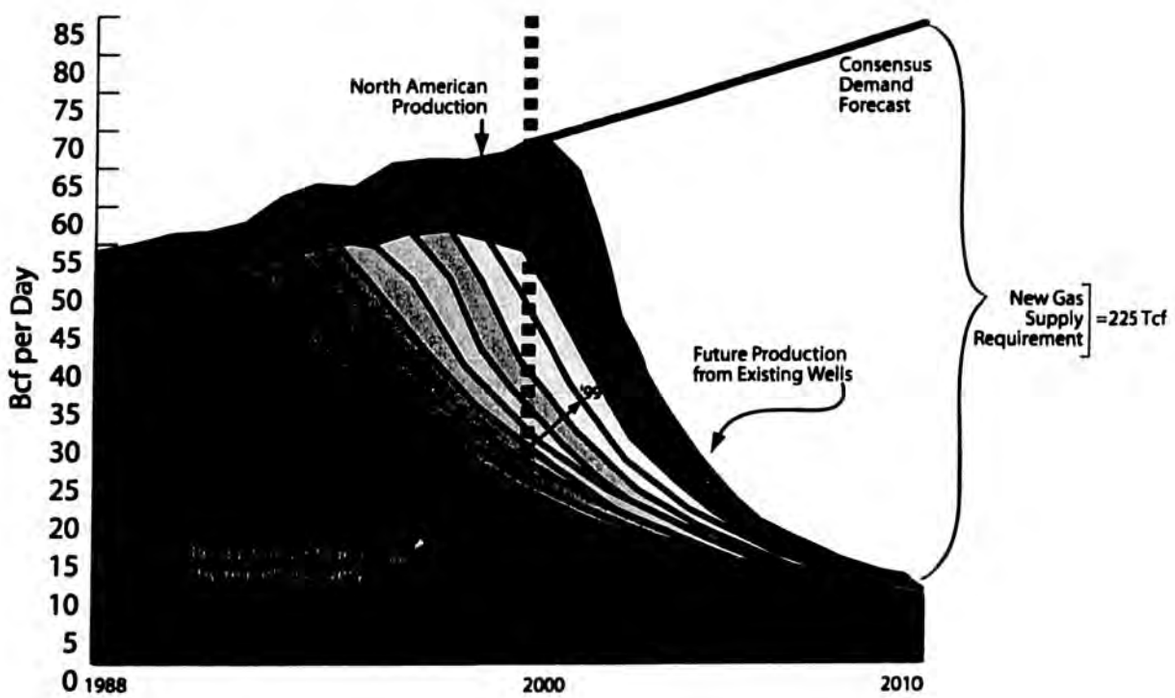
Judging whether consensus projections of North America gas consumption are accurate is, of course, difficult. A skeptic could point to forecasters' inability to predict, even for relatively short periods, prices of gas, electricity or crude oil. Relationships among these are critical inputs to any gas consumption forecast and given our inability to forecast them, no consumption forecast deserves much respect. Yet, short of adopting that agnostic view, there is no better basis for planning and conducting analyses of future markets than to utilize these projections, with due scrutiny of their assumptions.

A number of organizations and government agencies forecast gas consumption, including the Gas Research Institute, the U.S. Energy Information Administration, and the Canadian Energy Research Institute. These and others generally predict that gas consumption will increase 2-3 percent per year over the next two decades. These forecasts are based upon projections of economic growth and continued expansion of gas use in electricity generating plants and other industrial uses. Notwithstanding the recent dramatic price increases of 2000-2001, it is generally accepted that gas will continue to play a dominant and expanding role in North America's energy mix over the years to come. Certainly there are "wild cards" that could alter that picture, such as advances in fuel cell technology, distributed electricity generation (which could increase or decrease gas use depending on the technology developed), and environmental regulations. But none of these has risen yet to a level of commercial importance sufficient to cause forecasters to predict a slowing or reversal of gas consumption growth.

Thus, under almost any expected growth scenario, expansion of gas and NGL consumption in North America will continue. But that expansion cannot occur without development of new supply areas. By its nature, production from existing fields declines over time, or can be

maintained only with continuous development of new geologic strata or "step-outs" from already developed acreage. Advancing technology applied to existing supply areas surely will extend the economic life of those fields as it has in years past, but relying on such technology alone is not likely to satisfy growing consumption markets in North America. Figure 11 below illustrates the dual effects of a depleting gas supply and growing consumption – the gap between them grows quite rapidly indeed. That gap must be filled by technology applied to existing fields, or by development of new supply areas.

Figure 11



Source: "Potential Supply of Natural Gas in the United States - 2000," Potential Gas Committee.
Canadian Natural Gas Market Review & Outlook, May 2001.
"North American Gas Trends - 2000," Arthur Andersen/Cambridge Energy Research Associates.

Frontier Supply Regions

"Frontier" supply areas are regions believed or known to contain large undeveloped reserves for which little or no delivery infrastructure currently is in place. Alaska is one area; others include: deepwater Gulf of Mexico, Northwestern Canada (Alberta, British Columbia, Mackenzie Delta and Valley), U.S. Rockies, and U.S. coal-bed methane production (principally in Wyoming).

Though Alaska gas is farther away from the North American pipeline grid than any of the other areas, that fact alone does not mean that it will be developed last or valued less. Development of all frontier areas will require substantial investment, not only in exploration and drilling under adverse weather and terrain conditions, but also in infrastructure and facilities such as compression, treating, processing, gathering and pipelines. As noted in Chapter 1, current industry structure makes coordinated planning of such development quite difficult. By virtue of the long history of oil production in Alaska, and existing investment in North Slope infrastructure (seismic information, personnel, roads, etc.), Alaska gas development is more advanced than most of the other areas. The companies that will be producing most of Alaska's

gas – Exxon Mobil, Phillips, and BP Amoco – are large, established energy producers with access to financial capital and expertise. In addition, partners in one of the primary pipeline proposals – the Alaska Highway route – are established, experienced pipeline companies that have been organized and functioning since the late 1970s. Many of the necessary permits for that project are already in hand.

In addition, ANS gas production is relatively rich in NGL while some of the other areas are not. Coal-bed methane, for example, has no NGL but does have high levels of carbon dioxide and other impurities that must be removed. Treating and conditioning will add substantially to the cost of delivering that gas to the pipeline grid but unlike NGL, those costs will result in little or no offsetting sales value.

Production characteristics of two of the frontier areas – Gulf of Mexico and coal-gas – are particularly risky from the perspective of large up-front investments in facilities and other infrastructure. Production from wells in these areas tend to exhibit a brief "pop" of early production that tails off to low (albeit steady and long-lived) production thereafter. Gulf production in particular has caused great concern in this regard – new wells there have shown steep decline patterns.

In short, Alaska's existing status as a major oil producing region, coupled with the head-start (almost actual start) it experienced in the late 1970s positions it well in the competition it faces from other frontier supply areas in North America.

What North American Markets Will ANS Gas and NGL Serve?

Assuming that North American demand projections are realized, and that those projections result in development and integration of ANS gas and NGL, the two remaining factors of critical importance to its valuation concern which downstream markets ANS supplies will serve, and how the costs of shipping gas to those markets will be determined and applied in setting values in Alaska. Alaska gas and NGL most likely will be moved to North America via a dense-phase pipeline (one carrying gas and NGL in the same stream) that traverses or terminates in Alberta, Canada. Though LNG and Gas-to-Liquids (GTL) markets and related facilities also are potential outlets, they appear at this time to be secondary to pipeline transport.

Intermediate and Destination Markets. For purposes of analyzing determinants of ANS gas and NGL value, it is useful to distinguish two kinds of gas marketplaces in North America. Some are locations where end-users (or the local retail distributor that delivers to them) buy and consume gas. Call these "destination" markets. They ultimately are the destination points for gas produced and transported within North America. An "intermediate" marketplace is located upstream of destination markets, but downstream of individual gas wells or fields. These are places where gas supplies are aggregated, stored, traded, and routed on to destination markets. These were described in Chapter I as production-area "market centers" or "hubs." Transactions at these locations occur primarily between commercial parties (producers and marketers), with little or no involvement of end-users.

Large destination markets like Chicago and California are served by more than one upstream intermediate market and, conversely, large intermediate markets like Southwest Wyoming and West Texas, can reach more than one downstream destination market. Some Gulf Coast areas

enjoy both attributes – they are at the same time aggregation points for gas moving to downstream destination markets but also serve large nearby consumers.

Prices at destination markets and intermediate markets are greatly influenced by the number of supply or sales options available to them. For example, a destination market capable of receiving gas flows from a number of different upstream hubs provides valuable options for consumers there, and prices reflect those options. They are lower and more stable than prices paid by consumers in markets served by fewer upstream hubs.

For gas producers and other sellers, the same is true of upstream hubs – those with gas at a hub capable of routing supplies to more than one destination market typically enjoy higher and less volatile prices than those with supplies at a hub that serves only one downstream consumption market.

The large pipeline corridors spanning the North American gas grid are connections among intermediate markets and destination markets. Prices across the system adjust to prevailing market conditions at each node, and reflect the capacity and cost of transportation between nodes. Observed price differences between some pairs of nodes remain quite stable over time, reflecting a balance between gas flows and transport capacity. Other pairs experience volatile price relationships, caused by periodic imbalances in available supplies or demands relative to interconnecting capacity.

This distinction between intermediate and destination marketplaces applies to gas. For NGL the situation is somewhat different. As described in Chapter 2, there is no comparable pipeline grid and system of hubs for NGL to that which serves gas. Rather, NGL typically is first extracted upstream, near the point of gas production, then piped or truck downstream to one of a relatively few fractionation centers where final NGL products are produced and sold, usually to nearby large customers such as petrochemical companies. These fractionation centers can be considered analogous to destination markets for NGL.

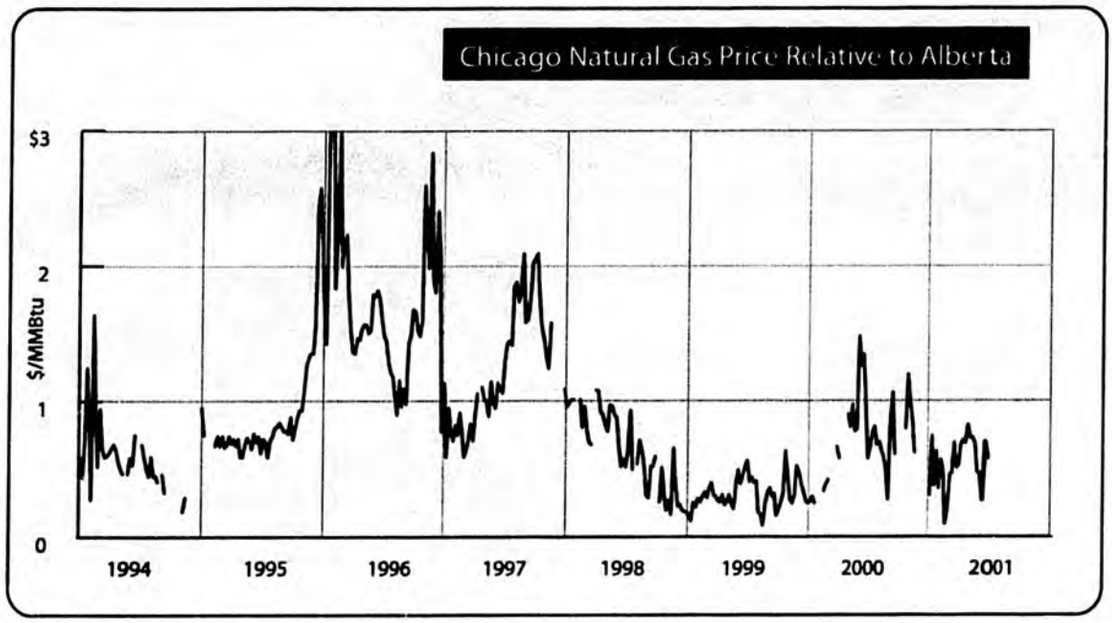
The Potential Role of Alberta in Valuation of ANS Gas and NGL

Under most of the pipeline transport options proposed for ANS gas, the routing will traverse and most likely terminate in Alberta, Canada. Alberta is an intermediate marketplace on the North American gas grid, but a destination marketplace for NGL. These facts point to some important questions whose answers in years to come will greatly affect ANS valuation. First, what are the downstream destination markets accessible to gas that is aggregated in Alberta, and what are current and expected transport costs and capacity to them? Second, if ANS gas is routed in such a way as to bypass (or "bullet through") Alberta in an effort to reach higher-value downstream gas markets, will NGL values at those markets suffer compared to the sales opportunities in Alberta? And third, if ANS gas and NGL bypass Alberta, where will it go?

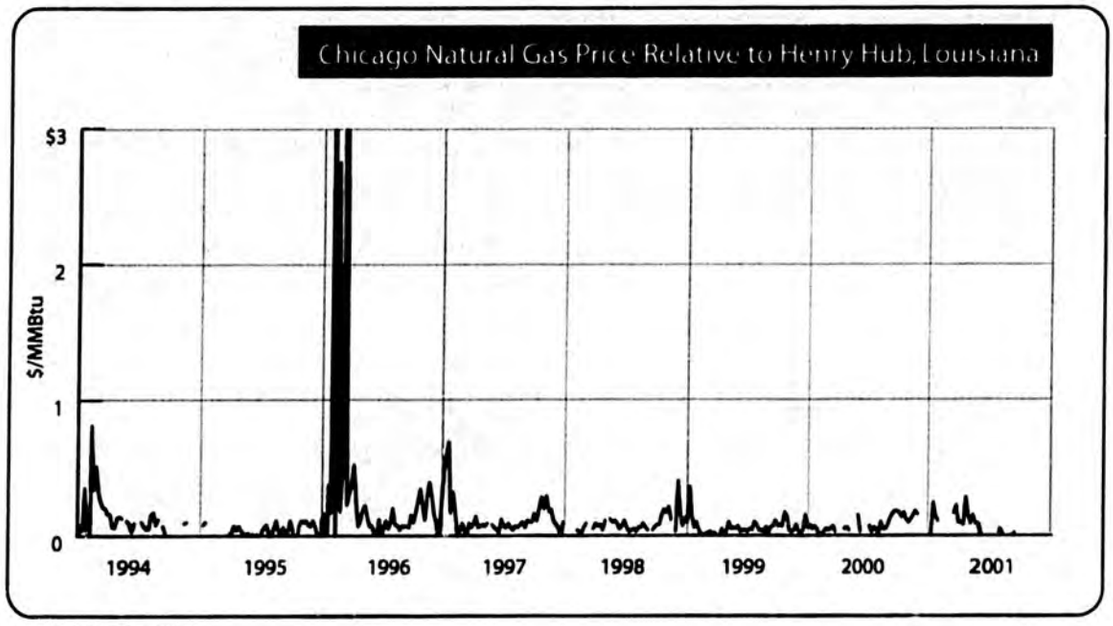
With respect to gas, the Alberta marketplace has a rough history. Though there is an established hub, or market center in Alberta that provides support facilities such as storage and trading services (actually there are several such hubs – See Figure 6 in Chapter 1), throughout its history to date, Alberta gas and the pipelines that carry it to downstream destination markets have failed to achieve a stable role in North American markets because production and takeaway pipeline capacity have not grown in a balanced way. This can be seen in the pattern of Alberta prices shown in Figure 12, which shows that prices in Alberta fluctuate substantially

compared to its primary destination market – Chicago. By contrast, prices at Henry Hub in South Louisiana have remained in steady alignment with Chicago prices.

Figure 12



Source: Natural Gas Week.



Source: Natural Gas Week.

These price patterns demonstrate two important aspects of gas valuation. First, the capacity and cost of transport links between a destination market and the upstream intermediate markets that serve it have a direct and potentially sizable influence on upstream prices. Without an ongoing balance between supplies and transport capacity, upstream prices are subject to considerable volatility. Also, the price patterns shown highlight the vulnerability of an intermediate marketplace, like Alberta, that sends most of its supplies to one downstream

destination market. While some Alberta gas can, and does, flow to Western U.S. markets, the bulk of it is shipped to the upper Midwest. In that situation, any excess pipeline capacity or bottlenecks that develop between Alberta and Chicago have an immediate effect on Alberta prices. If Alberta served Chicago and Western markets more equally, that effect would be dampened and Alberta prices would be more stable as a result.

The Alliance Pipeline. The prices shown in Figure 12 do not reflect much experience with the presence of the newest pipeline serving Alberta: Alliance. That pipeline went into service in December 2000. It carries Western Canadian gas to a point near Chicago. There the gas stream is processed at the Aux Sable plant, built in conjunction with the pipeline, and then is delivered to sales markets in the upper Midwest or to markets in the Northeast. The Aux Sable plant is the largest in North America in terms of gas throughput.

The Alliance/Aux Sable arrangement, where gas and raw mix NGL are transported together for a long distance, is unique among North American pipelines, but similar to the pipeline and processing arrangement envisioned for ANS gas. The advantage of that arrangement is that it transports raw mix NGL at lower cost than if that mix were extracted at or near production (as is the norm) and transported via a separate pipeline to a downstream fractionation center and finished products market. The disadvantage of that system is that it isolates its gas stream from the North American grid until it reaches markets near Chicago. This is because the grid does not accept gas containing raw mix NGL. That isolation limits sales and market options available to Alliance gas, though its proximity to large markets in Chicago mitigates this problem. In effect the Alliance pipeline is a large, long gathering system that delivers to a single processing plant. Only then can the gas enter the pipeline grid and participate in the merchant activities that take place along the grid.

The Alliance system has created excess pipeline capacity serving production in Western Canada. Accordingly, prices there are today little different than downstream market prices in Chicago, especially in comparison to past years when the reverse situation – not enough pipeline capacity – had depressed Alberta prices relative to Chicago. The situation today is favorable to producers in Alberta, but over the longer term, the see-saw relationship of pipeline capacity and production that has plagued Alberta over the years makes it difficult to assess its true and permanent economic role in North American gas consumption markets vis-à-vis other producing areas. The uncertainty impedes investment in exploration and transport facilities.

How Will ANS Gas and NGL Affect Alberta Markets? If flows into Alberta become commingled with other supplies that are aggregated there, ANS gas and NGL will become subject to the same market forces that act on all Alberta supplies. As noted, to date those forces have created periods of benefit to producers with gas there, as well as periods of very low prices when supplies faced constrained transport outlets. It is possible that introduction of a large new supply source that ANS gas would represent could bring the region to a size threshold sufficient to create a stable marketplace there, particularly if that size prompted creation or expansion of takeaway pipeline routes serving destination markets other than the upper Midwest. In that scenario, the Alberta region could become a northern "Henry Hub" with volumes from Alaska solidifying the Alberta region as a permanent and active marketplace for gas and NGL. As shown by Henry Hub, that reputation itself encourages investment in services and facilities that enhance trading, such as storage, organized trading markets, and take-away pipeline capacity. Financial markets also could recognize Alberta as a legitimate location for establishment of a northern futures market, for gas and/or NGL. That, of course, would further enhance the region's legitimacy as a stable and reliable market center.

But whether ANS gas and NGL will bring about market stability in Alberta is not a certainty. The added ANS volumes may simply offset production declines in that region, both for gas and NGL, and even should the ANS volumes represent incremental supplies there, the critical factor influencing Alberta prices is pipeline takeaway capacity relative to those supplies. Excess pipeline capacity can be expected to produce strong prices in Alberta, relative to downstream markets, while constrained capacity will generate weak prices. Alone, nothing about the increased size of gas supplies available in Alberta upon the arrival of ANS gas will change that fundamental fact. While excess capacity would benefit ANS producers and the State, its presence sets up the very see-saw phenomenon of alternating excess and constrained capacity that Alberta has experienced over the years. The same has occurred in other regions as well, the U.S. Rockies being a prime example. Experience shows that when pipeline capacity serving a region is tipped out of balance with the region's production capacity, it is difficult to regain that balance, and the result is fluctuating periods of abnormally low and abnormally high gas prices.

That fact highlights the importance of today's estimates of the volume of ANS gas that will be produced and piped into Alberta, and – equally important – the expected volume of Alberta gas (including perhaps supplies from the MacKenzie Delta and Valley areas) that also will be offered to market at that time. Such volume estimates are critical in determining how much takeaway pipeline capacity should be added, if any. If ANS plus Alberta volumes in 2010 exceed expectations, pipeline capacity out of Alberta may not accommodate it, with resulting low prices. Given the long lead-time for pipeline construction, such estimates of joint ANS/Alberta/MacKenzie production must be made and evaluated now, not after ANS gas begins to flow.

A second factor highlighted by Alberta's uneven development to date is the value of diversification of sales options. The value of ANS gas will be enhanced if, when it begins to flow to markets, it can readily access two or more large destination markets. The ability of ANS gas to flow either to Western markets such as California, or to Midwestern markets such as Chicago will give ANS producers valuable options. Again, given the long lead time associated with expansion or construction of pipelines from Alberta to either Western or Midwestern markets, it is vital that such pipeline proposals and plans be evaluated in conjunction with ANS development plans.

Can ANS Gas and NGL By-Pass Alberta?

If ANS gas producers determine that injecting their production into the Alberta marketplace is likely to subject them to too much uncertainty in terms of the rates and capacity of takeaway pipelines, they may devise means to avoid the Alberta market entirely. There are two potential ways to accomplish such a by-pass. First, the pipeline constructed to handle ANS gas could be extended to other markets downstream of Alberta. Or, the producers could obtain long-term commitments in advance of production on existing takeaway pipelines to assure themselves adequate capacity to move beyond Alberta at known, consistent rates.

These options pose a number of hazards and costs for ANS producers. The cost of a pipeline system extending from, say, Alaska's North Slope to Chicago would be enormous. Moreover it would effectively lock ANS producers into a single downstream sales market. In addition, if such a pipeline were, as planned, a dense-phase line carrying both gas and NGL, the NGL portion of the stream would by-pass a market (in Alberta) that may well be superior to any available near Chicago. Alberta is home to a large petrochemical industry (which Chicago lacks) that would

provide a substantial market for NGL. Arranging capacity on takeaway pipelines now serving Alberta would indeed enable ANS producers to sell NGL in Alberta and ship gas downstream to potentially more attractive sales markets, but that option must confront the risk of committing to a sizable portion of existing lines' capacity.

These are difficult choices for ANS producers but ones that, once taken, will substantially affect the value realized by them for years to come. One of the major conclusions of this Report with respect to royalty determination is that as those choices are being made and as events surrounding them unfold, it is critical that producers and the State share detailed information concerning the actual disposition of ANS gas and NGL. Information relating to transportation routes and costs, and ultimate sales realizations in whichever markets ANS gas and NGL ultimately reach should be made available to the State under either proceeds-based, or value-based royalty methods.

Netback Calculations for ANS Gas and NGL

The amount North America buyers in Alberta or markets further downstream will pay producers for ANS gas and NGL depends on prevailing price levels for gas and NGL available to them in other supply markets, and on the cost of moving ANS gas and NGL.

In the gas and NGL business the term "netback price" refers to a calculated, or estimated price, as opposed to an observed arms-length transaction price. A netback price is calculated by deducting transportation costs required to move gas or NGL from a producing area (where the netback is being applied) to a downstream market area where transactions occur and prices are collected and published. The use of netbacks is quite common to derive gas and NGL values at remote points in North America

The economic rationale for calculating and using a netback derivation of value is that competitive buying and selling should, in theory, force prices at different locations to equal the cost of transportation between them. If that relationship did not hold, it would give rise to an arbitrage profit opportunity. The actions of those seeking to exploit that opportunity would return the price differential to transport costs. The same concept also can be used to estimate the price of one product based upon observed prices for a second product and the costs of converting one into the other. So, for example, one could estimate prices for NGL in one location based upon prices for gas in a second location, less transport and processing costs.

The netback methodology for estimating value, though simple in theory (sales price less transport costs) requires special care in practice. Problems can arise in the determination and application of transport cost data in the formula. When a pipeline has excess capacity, its fully-allocated cost of service is little or no different that if it were running full (variable operating costs could differ, but these are normally a small part of total pipeline costs). But market forces tend to reduce the rates paid for transportation on a pipeline that has excess capacity to rates below those derived to recover total costs. Thus the actual price paid by a shipper using a line with excess capacity would be less than the pipeline's full cost of service.

The reverse could be true in the event of a pipeline bottleneck. In that case shippers competing to assure that their gas flows through the constrained line can reduce sales prices – effectively bidding up the price paid for using the pipeline. This time the true cost of using such a line, for purposes of applying a netback pricing methodology, would be higher than its fully-allocated cost of service. This has happened periodically in Alberta over the years, when pipeline capacity out

of the area has been constrained. Competition among Alberta producers bid up transport rates, usually through purchases of capacity in the secondary transportation market, to assure their gas moves through the constrained pipe. In that circumstance, a netback value utilizing the pipeline's tariff transportation rate would overstate actual gas sales value.

The conditions posed above – surplus or deficiency of pipeline capacity – are not uncommon and therefore except by coincidence, the actual economic costs to shippers of using a pipeline are unlikely to match up with tariff rates or other full cost-recovery transportation rates. The same is true for transportation and processing of NGL. The mis-match arises from the fact that gas and NGL pipelines and plants are large, long-lived sunk investments that are susceptible to fluctuating throughput. That can create for them periods of above-normal rates reflecting scarcity rents, and periods of below-normal rates that under-recover full costs.

Notwithstanding these complications associated with its use, the netback methodology is frequently used by gas buyers and sellers and, with appropriate care and access to relevant information concerning transport and processing costs, can be a good means of determining upstream values based upon downstream sales prices.

The potential complications warrant special attention in the case of Alaska gas and NGL because sufficient local trading is not likely to occur in Alaska to establish local, transaction-based measures of value and some type of netback methodology is likely to be used by producers and buyers of ANS gas to arrive at wellhead transaction prices. That task will be made somewhat more difficult if a single pipeline moves all ANS production because it will almost never be the case that the pipeline is optimally loaded, and accordingly there could be persistent and potentially unobservable transport rates above full pipeline costs, or persistent discounts below full costs. Either would make use of a netback methodology more difficult. It is in part for this reason that the State and producers should implement a period of intensive analysis and sharing of information during the initial years of ANS production in order to comprehend fully the nuances of netback value measurements for ANS gas and NGL. This suggestion is described in more detail in Chapter 6.

Chapter 4

Economic Aspects of Royalty

A royalty arrangement is a partnership between a resource owner and a resource developer. One contributes the resource, the other contributes expertise, investment, and effort to develop and "commercialize" the resource. A royalty agreement is a contractual mechanism for sharing that enterprise's benefits and responsibilities between these partners.

While the economic purpose and benefit of royalty is to capture efficiencies of specialization, delegation of development and marketing powers by the resource owner to a non-owner creates two kinds of problems that the partnership, through its contractual agreement, must address. The first is principal/agent problems arising from the fact that once the enterprise is launched the developer (the owner's agent in commercializing the resource) is likely to possess superior information, which it can be expected to exploit to its advantage where possible. The other is problems stemming from the difficulty (or impossibility) of using a long-term contract to provide certainty and stability to the partnership, while at the same time enabling adaptation to changed circumstance.

Principal/Agent Problems

In theory, an agent (in this case a gas production company, or lessee under an oil and gas lease) always acts in harmony with the principal's (mineral owner; lessor) interests. But in practice, agents can and often do pursue their own interests, even when doing so harms the principal. Where that danger is present and the parties foresee that it may cause problems, contractual agreements between principals and agents will specify oversight and monitoring mechanisms to police agent conduct.

A primary tool of oversight in gas royalty agreements is the lessor's right periodically to audit a producer's financial, production, and operating records to determine if performance has been in accordance with lease terms. That right serves both as a means to correct past errors in royalty sharing, and as an incentive for the producer to establish procedures and data collection that will demonstrate its faithful performance of obligations. Yet, as many producers and mineral owners can attest, audits often are complex, costly, and inevitably involve interpretation and judgment. These weaken its power to fully assure producer performance.

When such oversight is not possible or proves too costly to administer, a principal may seek to structure the agent's compensation in some creative way so as to align incentives. It would be possible of course for a gas producer to be paid by a mineral owner based upon time and expenses, with no payment linked to the volume or value oil and gas produced and sold. But clearly a producer under that deal has little or no incentive to maximize development value, or to operate efficiently. In contrast, permitting the producer to keep all product upon payment of a fixed amount – effectively buying the mineral from its owner – presents the difficult task for both parties of arriving at a price, with little or no information about future production levels or revenues.

For gas royalty agreements, a better compensation scheme than either of these extremes is one in which lessor and lessee share revenues from production, or share in physical production. Production or revenue sharing does better align producer and mineral owner incentives, but it is

subject to its own set of problems. For example, when revenues are shared (as opposed to physical volumes) the producer is positioned to exploit its natural advantage over the mineral owner regarding important revenue-related data such as reserve size, production levels, NGL content, costs, prices and sales opportunities. In a revenue sharing arrangement where that kind of information is used, the producer can capture a larger-than-agreed share by withholding or distorting such information. That can result from intentional acts of deception, but also simply because information used to calculate revenues and costs often requires interpretation and analysis. It is natural for a producer to apply interpretations favorable to it and to create and share information consistent with that interpretation.

Unfortunately, recognizing these problems does not aid much in their resolution. Audits and litigation of detailed contract terms are costly forms of contract administration. Writing a contract that accurately and fully describes which among many possible interpretations is the "correct" one is difficult at best. Even if such language could be agreed to, the danger remains that the lessor won't be able to detect and enforce it, even with audit rights, or to take steps to correct faulty sharing.

Contract Adaptability Problems

Oil and gas leases normally last for many years, well beyond the time frame that a lessor (mineral owner) and a lessee (producer) could be expected to predict how production and value determination will unfold. Royalty terms and sharing methodologies that today efficiently carry out the parties' intentions, can become onerous to one side or the other as circumstances change. There is no perfect royalty agreement in an ever-changing market environment – one capable of continuously implementing (at acceptable cost) the parties' initial intentions. Every agreement entails a tradeoff between the low-adaptability and high administrative cost of highly specified agreements that carry a degree of certainty, and the hassle and costs of (and potential hold-up associated with) renegotiating agreements with flexible but open-ended terms.

Types of Gas Royalty Sharing Agreements

The following is a list of royalty sharing principles, methodologies, and procedures often appearing in oil and gas royalty agreements:

1. Royalty paid in value

    a. Lessee producer's wellhead sale
    b. Wellhead sales proceeds of other, comparably-situated producers
    c. Lessee producer's sale proceeds from downstream sales points (netback calculations).
    d. Market value measures constructed from sale activity at major downstream markets to which lessee producer's gas could, or should, flow (netback calculations).

2. Royalty in Kind

These methods of royalty determination are briefly described below, with explanation of the economic benefits underlying them and difficulties presented by each.

Royalty in Value

1. Proceeds from producer's wellhead sales.

Though wellhead sales are not common today, this measure of value still appears in many leases. Clearly this value measure is the simplest and easiest to determine. The potential problems with its use relate to determination that the producer's proceeds are not artificially depressed (owing perhaps to sales to an affiliate, or to an independent party where compensation is received in forms other than sales proceeds), or that the producer's marketing efforts have been adequate to obtain the highest available proceeds.

2. Wellhead sales proceeds of other, comparably-situated producers.

This lease term evolved as a means of assuring that a producer's marketing efforts were adequate to obtain proceeds at least equal to those being obtained by comparable sellers. It is not an easy formulation to implement owing to the cost of obtaining relevant information concerning third-party transactions. Even where such information is available, the difficulty in implementing such a measure lies in performing an adequate comparison of sales terms other than price, and adjusting for legitimate sources of price differences such as gas quality or location.

3. Lessee producer's sale proceeds from downstream sales points (netback calculations).

Under this measure, a producer pays royalty based upon sales revenue it obtains for gas and NGL produced and sold. For sales that occur downstream from the wellhead, this methodology is intended to document actual sales and actual costs incurred to move and sell gas and NGL at those downstream locations. Some portion of such costs often are deducted from revenue to determine the lessor's share of value. In theory this arrangement can give a precise measure of value received by producer at the wellhead even when no wellhead sales occur. That makes it a highly desirable measure. Weighed against that substantial benefit, though, are a number of costs and administrative challenges:

a. The producer is likely to have superior access to information needed to make value determination. That leads to opportunity to cheat; when that occurs and is not detected, the lessor is deprived of his agreed-upon share. When it occurs and is detected, trust is destroyed, potentially raising future compliance and enforcement costs. That in turn heightens producer incentive to cheat, and the cycle continues. The result can lead to expenditure of resources by both sides that cut into the economic benefit to both parties of gas and NGL sales.

b. Because gas is transported in a displacement pipeline network, often it is not possible accurately to physically trace gas from point of production to point of sale. Therefore, by necessity, both revenues and costs in a net proceeds measure are accounting determinations that result from allocation procedures. These may bear little or no resemblance to true revenues and economic costs. In addition, the producer may aggregate lessor's gas with gas from other sources and provide valuable services to customers with the resulting "package" of gas. Attributing a portion of the value of such services to a particular lessor's gas is, again, a difficult task, involving accounting allocations that may bear little relationship to the value-

added by any particular gas source, and which may be subject to manipulation and distortion by the producer to reduce royalty sharing.

c. Affiliate transactions – likely to be present in movement and sale of ANS gas and NGL – also present opportunity for a producer to shift costs to avoid royalty payments. Producers that use affiliates to gather, process, transport or provide other services prior to sale have an incentive to inflate the costs reported for those activities so as to reduce the lessor's share of value.

d. The presence of NGL in Alaska gas, and the likelihood that such NGL will be transported long distances in the same stream as gas, complicates net proceeds determination because the cost of such joint transportation must be allocated between gas and NGL.

4. Market value measures constructed from third-party transactions at downstream markets (netback calculations).

Under this approach royalty payments use an agreed-upon downstream published price index, less agreed-upon market indicators of costs for moving of gas and NGL to that downstream sales point.

This approach does not require specialized information that only the producer is likely to possess and must share with lessor, and that puts them on more equal footing. It eliminates the opportunity for a producer to manipulate information to its advantage, and eliminates the perceived need by the lessor to impose costly compliance standards and procedures for producer to perform (or seek in turn to avoid or distort). Weighed against these benefits are the following disadvantages:

a. The downstream market index chosen may not reliably reflect value for the production covered by the royalty agreement. For example, the index could be subject to manipulation by one or more buyers or sellers at the index location. In addition, the agreed-upon index may be subject to short-run or long-run changes that do not accurately reflect changes in value of the royalty production. Also, the producer may find and sell into more lucrative markets than those chosen for index.

b. Published data for NGL transportation rates, processing costs and fractionation costs are not as readily available as published gas prices; in addition, such transport and processing information requires a greater level of interpretation. That presents opportunity for manipulation, distortion, or at least disagreement about, the meaning and application of such information.

c. Transport rates for ANS gas are likely to be highly influenced by the dominance of the three largest ANS producers in the takeaway pipeline. Even if producers do not own that pipeline, they still are likely to dominate its use and affect the structure and level of rates paid. This will affect value determination for both gas and NGL.

d. Market rates paid for transportation can differ from tariff rates, and short-term market rates may differ from long-term market rates. These complicate use of independent rates in netback calculations. To the extent that producers are positioned to affect collection and presentation of such information, the opportunity exists for manipulation.

Royalty in Kind

It is relatively rare that gas royalty is paid in gas. Unlike oil, gas cannot easily be stored at the lease by the lessor and disposed of separately from the lessee's production. That could potentially require duplicate or costly facilities. Instead, royalty-in-kind for gas, when it occurs, is more likely to involve separate contracting by the lessor or royalty-in-kind purchaser for use of the facilities also used by the lessee. It is possible for a lessor to administer such contracting itself – though that would appear to destroy the primary reason for a royalty partnership (specialization) – or it could contract with a "commercializer" that is distinct from the original lessee. Such contracting, though, presents the same kinds of problems as those discussed above inherent in the royalty relationship: establishing verifiable value principles, and implementing monitoring or compensation mechanisms. One advantage to royalty-in-kind is the possibility of harnessing periodic competition among potential marketers, including the lessee producer, to achieve maximum value. This alone is reason for a lessor to retain the option to switch periodically and with due notice, from royalty-in-value to royalty-in-kind.

Chapter 5

Alaska State Lease Provisions and Historical Experience with Oil Royalty

The discussion in this Chapter is not intended to provide a legal interpretation of the rights and obligations of the State and its oil and gas lessees. Rather, it is intended to illustrate and highlight issues and complexities likely to be encountered in valuation of the State's royalty gas and NGL.

Historical Experience with ANS Oil Royalty

ANS crude oil royalty is based on a determination of the value of the oil at the point of production, sometimes referred to as "wellhead value." For purposes of computing royalties, the value of ANS crude oil at the point of production has been computed both by the producers and the State using a netback mechanism since oil production first came on stream in mid-1977. Under that netback mechanism, value at the point of production is based on the value of ANS crude oil in destination markets where it is sold or consumed, less a measure of the cost associated with transporting the product from the North Slope to those markets.

The use of a netback approach to wellhead value determination arose from the way in which ANS crude oil was sold and consumed – in destination markets rather than at the point of production itself. Historically, the vast majority of ANS crude oil production has been transported thousands of miles from the North Slope of Alaska before being sold and consumed in destination markets. Today almost all ANS production is sold to refiners on the U.S. West Coast. Until recently, however, large volumes of ANS production were sold in markets as distant as the U.S. East Coast, the Caribbean and/or Asia.

Since most ANS crude oil has been sold by producers in destination markets far from the North Slope, nearly all of the transactional information regarding ANS value comes from sales of ANS in destination markets, rather than sales at the point of production itself. To the extent sales occurred on the North Slope, those transactions have almost always themselves incorporated a netback formula, with the price determined from ANS prices or values in destination markets, less a measure of transportation costs to those markets.

Alaska's Oil and Gas Lease Provisions

The companies that will produce gas from the Prudhoe Bay Unit and Pt. Thomson Unit signed lease contracts and royalty settlement agreements with the State of Alaska that will govern the calculation of the value of the State's royalty gas. The leases establish the State's right to retain a royalty share of production – usually 12.5 percent of gross production – and allow the State to take its royalty share in-kind or in-value. When the State takes its royalty in-kind, it sells its royalty share to third parties. When the State takes its royalty in-value, the lessees pay a cash value for it. The leases provide a mechanism to calculate the cash value of royalty paid in-value.

The DL-1 Lease Form.

Most of the leases in the Prudhoe Bay Unit are DL-1 form leases originally adopted by the State as administrative regulations in 1959. Some of the leases in the Point Thomson Unit also are DL-1 leases but many are new-form leases issued after 1978. There are several important differences between the DL-1 and new-form leases, but both establish the size of the State's royalty share and give the State the option to take its royalty share in-kind or in-value. They differ in the terms that describe the mechanisms to calculate value for royalty the State takes in-value.

Paragraphs 15 and 16 of the form DL-1 lease read as follows:

> ¶ 15. ROYALTY IN VALUE. At the option of the Lessor, which may be exercised from time to time upon not less than six months notice to Lessee, and in lieu of royalty in kind, Lessee shall pay to Lessor, the field market price or value at the well of all royalty oil and/or gas....
>
> ¶ 16. PRICE. The field market price or value of royalty oil or gas shall not be less than the highest of: (1) The price actually paid or agreed to be paid to Lessee at the well by the purchaser thereof, if any; or (2) The posted price of Lessee in the field for such oil or gas at the well, if any; or (3) The prevailing price received by other producers in the field at the well for oil of like grade and gravity or gas of like kind and quality at the time such oil or gas is removed from said land or run into storage, or such gas is delivered to an extraction plant.

Disagreements between the State and the Prudhoe Bay Unit lessees concerning DL-1 lease terms led to the *ANS Royalty Litigation* in 1977. Over the course of that litigation many of the lease terms were interpreted by the Superior Court and modified by royalty settlement agreements. Some of the issues ruled on include:

> 1. The cash value of the state's royalty share is equal to the price of the royalty oil or gas in the market(s) where it is sold, minus the cost of transportation to deliver that oil or gas to market.
>
> 2. Each lessee deducts its own reasonable and actual transportation cost from the price in the market(s) where its gas is sold, which may differ from the market value of that transportation.
>
> 3. In addition to transportation costs, the State bears field costs on royalty taken in-kind. When the State takes its royalty in-value, the lessees provide it free of field costs.
>
> 4. An early Superior Court ruling (that was later superseded by the 1980 royalty settlement agreements) held that the State could take its royalty in-kind only if it received at least as much from sale of the oil to royalty in-kind purchasers as it would have received if lessees paid royalty in value. Only then would taking the royalty in-kind meet the constitutional requirement that it be "in the best interests of the State and for the maximum benefit of its people."

The New-Form Lease.

In 1980 the State began issuing new-form leases, with royalty and value terms intended to minimize opportunities for dispute over royalty value. These leases have never been litigated. Like the DL-1 leases, the new-form lease describes a variety of mechanisms to calculate royalty value and the lessee must use the mechanism that yields the highest value.

An example of the value term found in the new-form lease is illustrated as follows:

¶ 36. VALUE.

(a) For the purposes of computing royalties due under this lease, the value of royalty oil, gas, or associated substances shall not be less than the highest of
(1) the field price received by the lessee for the oil, gas, or associated substances.
(2) the volume-weighted average of the three highest field prices received by other producers in the same field or area....
the lessee's posted price in the field....
the volume-weighted average of the three highest posted prices in the same field...

(b) If oil, gas, or associated substances are sold away from the leased or unit area, the term 'field price' in subparagraph (a) above will be the cash value of all consideration received by the lessee or other producer from the purchaser of the oil, gas, or associated substances, less the reasonable costs of transportation away from the lease or unit area to the point of sale. The 'reasonable costs of transportation' are as defined in 11 AAC 83.228 and 11 AAC 83.229 as those regulations exist on the effective date of this lease.

(c) In the event the lessee does not sell in an arm's length transaction the oil, gas, or associated substances, the term 'field price' in subparagraphs (a) and (b) above will mean the price the lessee would expect to receive for the oil, gas, or associated substances if the lessee did sell the oil, gas, or associated substances in an arm's-length transaction, minus reasonable costs of transportation....The lessee must determine this price in a consistent and logical manner using information available to the lessee and report that price to the state.

(d) The state may establish minimum values for the purposes of computing royalty on oil, gas, or associated substances obtained from this lease, with consideration being given to the price actually received by the lessee, to the price or prices paid in the same field or area...to posted prices, to prices received by the lessee and/or other producers from sales occurring away form the leased area, and/or to other relevant matters. In establishing min m values, the state may use, but is not limited to, the methodology for determining 'prevailing value' as defined in 11 AAC 83.227. Each minimum value determination will be made only after the lessee has been given notice and a reasonable opportunity to be heard. Under this provision, it is expressly agreed that the minimum value of royalty oil, gas, or associated substances under this lease may not necessarily equal, and may exceed, the price of the oil, gas, or associated substances.

The new-form lease explicitly acknowledges that the lessees will sell royalty gas in distant markets and that prices of gas in these markets are appropriate data in determining royalty value. The lessees are allowed to deduct their own reasonable costs of transportation.

Paragraph 36(d) allows the State to define the minimum value for its royalty. Although the lessees retain a mechanism to voice disagreement with the State, the lessee must pay the higher-of the minimum value or the highest price yielded from the other lease terms. The new-form lease also requires the State to evaluate the same kinds of information that it might consider when establishing the Paragraph 15 value under the DL-1 lease. A critical distinction between Paragraph 15 and Paragraph 36(d) is that the lessees must accept Paragraph 36(d) as determined by the state to be the minimum value for their royalty obligation.

Disputes Concerning Proper Calculation of Royalty Values

Settled ANS Gas Royalty Disputes. A 1980 royalty settlement agreement anticipated the construction of a pipeline to take ANS gas from the North Slope for Prudhoe Bay only. It includes details about how the State and the lessees are to account for the royalty deduction for the cost of removing CO2 and other impurities in a gas conditioning plant. The conditioning costs to be deducted from the value of royalty gas will depend on whether the lessees own the plant and whether the plant is a unit facility or part of a pipeline project. The magnitude of conditioning costs will not be known until the gas conditioning plant is built.

The same agreement provides a formula for calculation of Prudhoe Bay Unit field costs on oil and gas that would apply to all royalty dispositions whether taken in-kind or in-value. At present, the field cost deduction for gas produced from the Prudhoe Bay Unit calculated per the 1980 agreement is $0.19 per mcf.

In 1995, near the conclusion of the *ANS Royalty Litigation*, the State and lessees entered into several gas royalty settlement agreements and set out royalty valuation provisions that differ from the requirements of the DL-1 lease. These provisions apply only to sales of royalty bearing gas referred to as "Local Gas," defined as dispositions of royalty bearing gas volumes less than 50 mmcf/d. These settlements also determined a royalty deduction on "Blendable NGLs" produced from the Prudhoe Bay Unit, i.e., NGLs that can be blended with oil for shipment on TAPS.

A significant term in the 1995 gas royalty settlement agreements prohibits the lessees from charging, as a royalty deduction, the cost of Prudhoe Bay's Central Gas Facility on gas sold for deliveries to an ANS gas pipeline project. If a lessee sells "New Gas," defined as a disposition of gas in excess of 50 mmcf/d, the gas royalty settlement agreements leave the question of appropriate valuations and royalty deductions up to the provisions of the DL-1 lease provisions. Volumes of this magnitude would be expected to supply the ANS gas pipeline. In the event that the ANS gas pipeline is built, we understand from DNR that the State will look to Paragraph 15 and 16 of the DL-1 to value most of the royalty gas produced from the Prudhoe Bay Unit. The State and the lessees have not agreed on an interpretation of all of the terms in Paragraph 15 and 16.

Settled ANS Oil Royalty Disputes. From the start of ANS oil production the producers computed royalties using one of two basic approaches: 1) proceeds or 2) a measure of market value. In some instances producers used a combination of the two approaches depending on how they

marketed their oil. Where producers sold oil to another party they often based royalties on the proceeds they received in those sales. Where producers used their ANS oil production in their own refineries, they determined royalties based on a measure of market value. In both cases producers netted back these prices to the point of production by subtracting their determination of transportation cost from the North Slope to the point of delivery.

ANS producers used a number of approaches in determining market value for ANS production. In some cases producers constructed market value-based, transparent formulae. These included basing ANS value on the prices of one or more "proxy" crude oils sold in the same destination markets in which ANS was delivered, or basing ANS values on the average price received by the producer in its own sales transactions. In other cases producers determined market value based on a more subjective "assessment" of market factors.

The manner in which the major producers computed royalties was contested by the State for many years and was the subject of litigation between the State and producers in the *ANS Royalty Litigation*. In that litigation the State took issue with the way in which the producers calculated the proceeds they received from sales to third parties and the methods used by producers to determine market value. The State also took issue with many of the cost deductions made by the producers when netting back destination values to the point of production. In the *ANS Royalty Litigation* the State obtained detailed data relating to all transactions entered into by the producers for the purchase, sale, exchange and transport of ANS oil. The State also obtained data from the producers regarding the cost of transporting ANS oil from the North Slope to destination markets. The process of obtaining and analyzing this information in the context of litigation was lengthy and costly, involving the efforts of many people over several years.

The State analyzed the transaction data it obtained from producers during litigation to determine the proceeds actually received by the producers to develop a measure of ANS market value that would closely track prices actually received by ANS producers; it analyzed the information obtained regarding cost deductions to determine appropriate deductions when netting back from destination values. Based on its analysis of producers' transactions, the State made determinations of proceeds and ANS market values that often resulted in large discrepancies relative to the proceeds and market values reported by producers for royalty payments. In some cases these discrepancies amounted to several dollars per barrel over extended periods of time. Likewise, the State's analysis of ANS transportation costs resulted in large differences relative to the costs claimed by the producers.

The State and major producers settled the oil valuation phase of the *ANS Royalty Litigation* in the early 1990s. As a result of these settlements, the three major producers agreed to pay the State a total of $736 million in additional back royalty payments. In addition, the State and major producers agreed on a prospective approach for determining royalty values. The prospective valuation approach incorporated in the royalty settlement agreements between the State and producers established a netback formula for royalty payments that consisted of: 1) a destination value measure, and 2) specified cost deductions for transportation to destination markets. Destination values were established by reference to independent, published market assessments for ANS and other crude oils; transportation deductions were based on agreed-upon costs that were, in some cases, indexed to changes in industry-wide transportation cost measures.

The royalty settlement agreements include provisions that allow either party to "reopen" or renegotiate terms of the valuation formula with respect both to destination valuation and to

cost deductions. Either party may reopen in the event it feels the current formula does not produce results that are consistent with true ANS market values. The agreements also specify that if the parties fail to reach agreement on a new formula after one of the parties has formally reopened the negotiation, then their dispute will be settled by binding arbitration.

Since entering into royalty settlement agreement in the early 1990s, the State and producers have reopened agreements on several occasions. In each instance, the parties have been able to reach agreement without arbitration. In some instances, the parties have amended the agreements without resorting to a formal reopener notice.

Knowledge Gained by the State after Years of Analysis The ANS oil royalty settlement agreements between the State and producers have provided a workable, mutually agreeable framework for royalty valuation over the past decade. Implicit in the agreements is recognition of the costs of compliance and enforcement associated with detailed proceeds accounting (and audits) and the potential controversy surrounding a subjective determination of appropriate value measures. Also implicit is recognition of the economy associated with use of independent, publicly available measures of value and costs that are themselves regularly used by industry participants when contracting for the sale or transportation of ANS.

For the State, the agreements have provided a mechanism that enables it to receive a measure of market value for its oil without the need to engage in continuous, detailed auditing of producers' transactions and accounting data. For the producers, the agreements have provided a formula for paying royalties that removes uncertainties as to how to comply with payment provisions of the lease agreements. That certainty is valuable to the producers.

The success of the royalty settlement agreements in striking a balance among the interests of all parties is indicated by the fact that the parties have on occasion renegotiated agreements without the aid of arbitration.

The royalty settlement agreements were negotiated by the State after ANS crude oil production had been flowing for more than a decade. They were negotiated after the State had the opportunity to analyze the way in which ANS was transported and sold. By the time the agreements were put in place the State had reviewed thousands of contracts involving ANS transportation, sales and exchanges, as well as accounting statements used by producers to support cost deductions in their netback calculations.

The experience and expertise gained by the State through its analysis of data and contracts involving ANS transportation and marketing was a key factor in the State's ability to negotiate the prospective royalty valuation formulae contained in the agreements. This experience helped insure that the valuation methodology agreed to by the State accurately captured ANS value at the outset, and that the agreements gave the State the ability to modify terms in the event markets changed going forward.

Since ANS production came on line in the late 1970s, oil markets have undergone several changes that have affected markets into which ANS has been sold. For example, during the first few years of ANS production, crude oil markets were characterized by long-term contractual relationships between producers and buyers. World events in 1979 set in motion a multi-year change in the oil industry that resulted in greater emphasis on short-term or spot markets. This in turn led to a rise in importance of financial or "paper" markets. In short, the world and the way in which crude oil – including ANS – was marketed changed dramatically over the first

decade of ANS production in a way that was not anticipated by market participants when ANS production first came on line.

Oil markets have continued to evolve as ANS production has declined since the early 1990s. Today, all ANS production is marketed on the U.S. West Coast or in Alaska. The structure of the West Coast market itself has undergone dramatic transformation over the past several years as refiners have merged and consolidated into fewer companies. And as ANS production has declined, West Coast refiners, that until recently benefited from a surplus of ANS production relative to refining demand, have had to import large quantities of foreign crude oil again. This recent change has brought a renewed emphasis on long-term relationships again at the expense of spot transactions. It also has brought about direct competition between ANS crude oil and foreign crude oils imported into the West Coast.

Implications of Oil Royalty Experience for Gas Royalty Determination

As these changing market environments illustrate, even the best-conceived royalty valuation formula can go astray over time unless it adapts to new conditions. This in fact has happened periodically during the past decade that the royalty settlement agreements have been in place. The agreements have been modified several times. Each of these was occasioned by a recognition that market conditions had changed substantially enough to change the nature of the bargain originally agreed to.

This history of ANS oil royalties highlights both the need to maintain flexibility in the procedures and mechanisms used to value and pay gas and NGL royalties and, more importantly, the critical need for information sharing between producers and the State as to how ANS gas and NGL is moved to market and sold. As discussed in Chapter 3, producers of ANS gas and NGL face a number of difficult marketing and transportation choices with respect to gas and NGL. How they solve those in a way that maximizes their own value will no doubt require experimentation with various marketing and transport options. While ANS producers and the North American markets that they sell into adjust to the new volumes and settle into a balanced, consistent flow of gas and NGL to sales markets, information as to actual dispositions will be vital both to producers and to the State in understanding how ANS gas and NGL value can be maximized.

Chapter 6

Conclusions

This Report has provided an overview of gas and NGL markets in North America as they are structured and operate today, with observations as to how those markets can be expected to perform in years to come. In addition, we have described and analyzed market factors that are likely to determine the value of ANS gas and NGL when these begin to flow to North American markets within the next several years, and economic considerations relevant to structuring and applying royalty principles, methods, and procedures to best accommodate the State's interests as lessor of that gas and NGL. This Chapter draws these findings together in summary form.

Gas and NGL Markets in North America

1. North American gas markets have become flexible and responsive to supply and demand conditions, and are likely to remain so in years to come. Gas flows and prices respond to localized supply and demand conditions and pipeline capacity constraints or surpluses. Producers, marketers and end-users utilize the extensive pipeline network, along with storage facilities, market centers and financial instruments to consume and produce gas efficiently and to capture value when and where it arises.
2. Gas consumption in North America is expected to exceed 30 Tcf per year within the next 10 to 20 years. To accommodate that demand growth, producers not only must replace today's depleting wells, they must find and develop new reserves. Alaska gas will be one of those new supply sources. Substantial infrastructure – pipelines, storage, hubs – must be built to move new-found reserves to markets.
3. Based upon historical trends, gas and NGL prices – always a hazard to forecast – are unlikely to rise substantially, except for periodic spikes at various times and at various locations in response to temporary conditions.
4. NGL markets in North America are not as commoditized as gas markets. There are fewer active trading points, and the transport network, less extensive than that for gas, does not for the most part operate as a displacement network. That reduces opportunities to exploit logistic and financial efficiencies that are present for gas.
5. NGL finished product prices are established at a handful of market centers. Upstream raw-mix prices are set by reference to market center prices, less deductions for transport and fractionation costs.
6. NGL finished product prices are buffeted by numerous and diverse influences including oil and gas prices, petrochemical demand, heating fuel demand, and oil refinery output. The family of NGL finished products – ethane, propane, butane, and others – are each subject to distinct market forces. Wellhead NGL is a mixture of these finished products and therefore its value is affected to some degree by each distinct factor in addition to locational factors, transportation costs and fractionation costs.
7. NGL markets are likely to operate in the future much as they do today – largely the domain of a comparatively small group of specialists. Raw-mix NGL prices will continue to be set by downstream product prices (published and available for select locations) less transportation and fractionation cost deductions (limited reliable public information).

ANS Gas and NGL Value

1. Alaska gas most likely will enter the North American market at Alberta, Canada or at consuming markets downstream of Alberta. Alberta is a large "node" on the North American gas grid, but one which to date has been subject to periodic price fluctuations owing to imbalanced development of gas production and takeaway pipeline capacity.
2. Alaska wellhead gas value will be set by conditions in North American markets and by transport costs from the North Slope of Alaska to those markets. Even should in-state markets develop substantially, the bulk of produced volumes will flow to out-of-state markets.
3. Alaska NGL also is likely to enter North American NGL markets at Alberta, which is a major NGL trading center in North America.
4. Alaska gas and NGL are likely to be transported to Alberta in the same pipeline. While that may be the least cost method to move ANS gas and NGL, it complicates determination of transport costs for both gas and NGL. Transport cost is an important component in determining the wellhead value of both products.
5. The time horizon over which ANS gas and NGL will be produced is long – 50 years or more. It is not possible now to predict fully how North American gas and NGL markets will change over that time period, or to predict the evolving role of Alberta within the North American gas grid and in its role as a major NGL and petrochemical center. These will be the major factors to understand and factor into ongoing ANS value determination. Only time and experience can reveal the specific consumption markets to which ANS gas will flow downstream of Alberta.

ANS Gas and NGL Royalty

1. Efficient and workable royalty agreements should specify principles, methodologies and procedures to be used by lessor and lessee as they share production or revenues. In addition, there should be a well-understood and readily-identifiable mechanism that tells the parties when to modify existing methodologies or procedures (or change to entirely new ones) in order to remain faithful to their initial sharing principles.
2. The State's experience with oil royalty provides a useful template for gas and NGL royalty. Lessons learned and expertise developed there can be applied to gas and NGL royalty. In particular, the basic approach taken for oil – to gather and analyze information as to actual proceeds, then construct value measures from that information – should serve the State and producers well for gas and NGL royalty.
3. Because the role of ANS gas in North American markets for the next 50 years cannot be predicted today, the parties should provide sufficient royalty flexibility to adapt methods and procedures as conditions warrant. Within that framework though, there is room for agreement now as to first principles of production and/or revenue sharing, but these should not be carried to the point of eliminating adaptability.
4. Information is a primary source of royalty problems, even for mature production at or near major markets. ANS gas, at least in the early years of its production, and probably for much longer than that, enjoys neither of those characteristics. Information sharing therefore takes on heightened importance for ANS gas and NGL royalty. This suggests that the State and producers may both be well served to put in place a mechanism at the

outset of production for generating and sharing information that is above and beyond that which might be called for in mature areas.

5. The information so shared should relate to the actual sale of ANS gas and NGL as well as actual transport and processing costs incurred. Agreement should be reached as to measures of such revenues and costs that accurately track ANS gas and NGL flows and transactions from points of production to points of sale. The State should be allowed to utilize source documents and data in order to apply and test the effects of alternative revenue and cost allocations where commingling of gas makes such allocation necessary.

6. Information from such a mechanism will guide the State and producers in understanding how ANS gas and NGL fits into North American markets. It is likely to take some time for market dynamics there to adjust fully to introduction of ANS gas and NGL. The heightened information sharing period should last until markets have digested ANS volumes and an adequate understanding is reached as to how and where ANS volumes are sold and priced.

7. When that level of understanding is achieved, it may be possible then to turn to mechanisms that utilize published market information and are less costly to implement, such as use of downstream market price indicators and market-based transport and processing cost indicators.

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ALASKA HIGHWAY NATURAL GAS POLICY COUNCIL



REPORT TO THE GOVERNOR

VOLUME ONE

NOVEMBER 30, 2001



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Alaska Highway Natural Gas Policy Council

Report to the Governor

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Note to Readers: This is Volume I of the Alaska Highway Natural Gas Policy Council Report to the Governor. Volume II includes public testimony, selected presentations, and subcommittee meeting summaries. For copies of Volume II, please contact the Governor's Office at (907) 269-7450.

Section I:

Council Background

ADMINISTRATIVE ORDER NO. 188

I, Tony Knowles, Governor of the State of Alaska, under the authority of art. III, secs. 1 and 24 of the Alaska Constitution, establish the Governor's Alaska Highway Natural Gas Policy Council (Council).

PURPOSE

1. Alaska North Slope gas development and transportation to market is of vital public interest. It is in the best interest of the people of Alaska that a North Slope natural gas commercialization project advance, to the maximum extent allowed by law, Alaska hire and use of Alaska businesses; Alaskan access to gas; and a fair share of revenues for Alaskans. This project should improve the standard of living for Alaskans by providing feedstock for new industries, community access to gas, and gas for future commercialization projects that may become feasible as market conditions improve. It is essential that Alaskans have a voice in determining how the state will achieve these goals.

2. As Governor, I join the many Alaskans in believing that the only viable and environmentally responsible project is a natural gas pipeline from Prudhoe Bay to Fairbanks, and then along the Alaska Highway through the Yukon Territory and Alberta to connect with distribution systems in America. This route was approved by Congress in 1977 and is the subject of an international treaty with Canada.

3. The purpose of the Council is to engage Alaskans representing a broad spectrum of Alaska interests, experience, and geography to advise the Governor and the Alaska Highway Gas Pipeline Cabinet in determining how the state can best promote the Alaska Highway North Slope natural gas pipeline project and maximize benefits for Alaskans.

DUTIES

1. The Council shall hold statewide meetings to obtain the public's views on how the state can best promote a gas commercialization project and maximize benefits for Alaskans. During

the meetings, the Council shall present a summary of project options and general topics for discussion.

2. Before the statewide meetings, the Council shall meet to plan its work schedule and prepare the presentation for the meetings.

3. No later than November 30, 2001, the Council shall present a summary of public comments, consensus recommendations, and other information gathered to the Governor, the Alaska Highway Gas Pipeline Cabinet, and the public.

4. The Council shall deliberate and make recommendations on topics related to natural gas commercialization, including

   a. the benefits of natural gas development to Alaska communities, including those located in rural areas of Alaska;

   b. the best uses of the state's royalty share of the gas and promotion or attraction of investment for in-state and value-added processing;

   c. the costs and benefits of the state taking delivery of its royalty share of the gas in Alaska versus allowing a project developer to include the gas in its delivery flow to the lower 48 states;

   d. options for projects utilizing gas-to-liquids, liquified natural gas, and natural gas liquids;

   e. demand for in-state natural gas consumption and its effects on a gas project;

   f. environmental impacts and necessary protection measures;

   g. training and readiness of Alaskans for jobs on a gas project, use of the Alaska labor pool by contractors and subcontractors, and use of Alaska businesses; and

   h. state promotion and facilitation of project financing, including potential ownership by the state of some or all of a project.

MEMBERSHIP AND GENERAL PROVISIONS

The Council shall be comprised of Alaskans representing a diversity of interests, experience, and geography and appointed by the Governor to serve at the pleasure of the Governor. Members of the Alaska Highway Gas Pipeline Cabinet shall serve as non-voting, ex-officio members of the Council.

The Office of the Governor and other state agencies shall provide professional and administrative staff assistance to support the activities of the Council. The Department of Law shall provide legal assistance to the Council.

To reduce costs, the Council shall use teleconferencing or other electronic means to the extent practicable in order to gain the widest public participation at minimum cost.

The Council shall establish procedures for voting and meetings. Council members who are not state employees serve without compensation and are entitled to per diem and travel expenses in the same manner permitted for members of other state boards and commissions. Per diem and travel expenses for members of the Council who are appointed as a member of a state agency are the responsibility of that state agency. The Governor shall designate two members of the Council as co-chairs. Meetings of the Council shall be conducted and notices of such meetings provided in accordance with AS 44.62.310 (Open Meetings Law).

AMENDMENTS AND REVOCATIONS

This Order amends Administrative Order No. 187 to change the name of the Gas Pipelines Cabinet to the Alaska Highway Gas Pipeline Cabinet.

This Order revokes Administrative Order 152.

This Order takes effect immediately.

DATED at _____, Alaska, this ____ day of January, 2001.

_____

Tony Knowles
Governor

FOR IMMEDIATE RELEASE: January 26, 2001 01-027

KNOWLES ANNOUNCES CO-CHAIRS OF NEW ALASKA HIGHWAY NATURAL GAS POLICY COUNCIL

Prominent Alaskans to Help State Direction on Gas Development; International Energy Firm to Advise State and Alaskans

ANCHORAGE—Continuing his push to develop an Alaska Highway natural gas pipeline, Gov. Tony Knowles today announced two initiatives to further commercialization of Alaska's North Slope gas. By state Administrative Order, the governor created the Governor's Alaska Highway Natural Gas Policy Council to be chaired by two prominent Alaskans – retired ARCO Alaska Senior Vice President Frank Brown of Anchorage and former Fairbanks North Star Borough Mayor Jim Sampson of Fairbanks.

Knowles also announced that his administration has contracted with one of the world's top international oil and gas experts, Cambridge Energy Research Associates, to provide Alaskans expertise and analyses of various aspects of gas development.

"When it comes to natural gas, after two decades of false starts and broken dreams, the economic and political stars are finally aligned in Alaska's favor," Knowles said. "Despite our distance from domestic markets, our natural gas is more economic now than ever. The Governor's Alaska Highway Natural Gas Policy Council will engage the public as it analyzes the many issues related to gas development and makes recommendations to Alaskans."

The governor asked the council to begin its work soon and report back with recommendations by November 30, so their work can be incorporated into gas line legislation and project development. Knowles noted that his new special assistant for economic development, Ken Freeman, will provide staff assistance to the council.

Cambridge Energy also will assist the council and Alaskans in analyzing the many aspects of gas development. "Led by Pulitzer Prize-winner author Daniel Yergin, who won the honor for his thorough history of world oil development, Cambridge Energy can provide the objective market analysis we need to make the important public policy decisions facing Alaska," Knowles said.

The governor also used his remarks to the Alliance to praise developments in the oil patch.

Citing a recent analysis of the impact of the oil industry on Alaska's economy, Knowles noted that more than one in ten private sector jobs in the state are the result of this industry, which also has the highest average wage and the largest private sector payroll in Alaska. The investment the oil and gas industry makes in Alaska each year is roughly equal to the state's annual general fund spending.

"Alaska's major producers, especially BP and Phillips, are working hard to keep those good news numbers coming by aggressively exploring for oil and gas on the North Slope," he said. "By investing about 25 percent more in capital spending, Phillips has targeted a 14 percent oil production increase over the next 5 years; BP 17 percent.

> "Other companies such as Alberta Energy, Unocal, Marathon and others, are equally bullish on the Slope and in Cook Inlet. Last fall's North Slope area-wide sale set a record for state oil and gas lands leased for exploration, more than 713,000 acres," Knowles said. "In Cook Inlet, there's a renewed interest in exploration of natural gas and Forest Oil set the first new platform in Cook Inlet since 1986. The state is responding to all this interest with 16 area-wide lease sales in the next 5 years."

After Alaska's success in convincing the national administration to open the National Petroleum Reserve-Alaska to oil and gas exploration, Knowles said the challenge now is to persuade America and Congress to permit environmentally responsible development in the Arctic National Wildlife Refuge.

"We breathed a sigh of relief when the Clinton administration listened to Alaskans and declined to make ANWR a national monument," he said. "With a new national administration, we're better positioned for success in ANWR. But we shouldn't kid ourselves into believing we face a cakewalk.

"Our challenge is to demonstrate, using the latest technology and relying on the world's safest oil transportation system, that we can develop the oil beneath the refuge, while protecting the environment and fish and wildlife that we value so much and which are such an important symbol for so many Americans," the governor said.

Knowles has taken a number of steps to advance gas development, including visiting personally with the top officials of Alaska's oil and gas producing companies. He co-sponsored a natural gas summit in Columbus, Ohio attended by experts from more than 40 states.

Two weeks ago, he signed Administrative Order 187 creating a special Natural Gas Pipeline Cabinet and directing state agencies to work aggressively for timely one-stop permitting and right-of-way preparation. The Knowles administration has introduced legislation extending the state's ability to negotiate tax flexibility for natural gas projects, like an Alaska Highway gas line.

These initiatives are supported by a multi-million dollar budget request, which Knowles has asked the Legislature to act on quickly.

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FOR IMMEDIATE RELEASE: February 2, 2001 *01-035*

KNOWLES ADVANCES ALASKA HIGHWAY GASLINE WITH POLICY COUNCIL
Civic, Business Leaders Included in 28-Member Panel

Citing their breadth of experience and leadership in keeping Alaska's economy healthy, Gov. Tony Knowles today announced 26 members of the Governor's Alaska Highway Natural Gas Policy Council. The council will spend the next 10 months focusing on the best ways to advance construction of a natural gas pipeline down the Alaska Highway.

"This council is one of the smartest, most experienced, and highly dedicated group of Alaskans ever assembled for a single purpose: to help guide Alaska public policy as we build a natural gas pipeline," Knowles said. "I'm honored each of these Alaskans answered my call to public service for this important effort. I know Alaskans will be reassured that their views about this enormous project will be considered."

Knowles created the council January 26, when he signed an administrative order to "engage Alaskans representing a broad spectrum of Alaska interests, experience, and geography to advise the Governor and the Alaska Highway Gas Pipeline Cabinet in determining how the state can best promote the Alaska Highway North Slope natural gas pipeline project and maximize benefits for Alaskans."

The Governor last Friday announced the council's two co-chairmen: retired ARCO Alaska Senior Vice President Frank Brown of Anchorage and Jim Sampson, Executive Director of the AFL-CIO in Alaska and a former mayor of the Fairbanks North Star Borough. The 26 other members of the council appointed by the Governor today include:

- Former state representative and Kenai Peninsula Borough Mayor Mike Navarre;
- Anchorage Mayor George Wuerch;
- Former state Attorney General Grace Schaible of Fairbanks;
- Bill Corbus, president of Alaska Electric Light and Power Company of Juneau;
- Former state Attorney General Charlie Cole of Fairbanks;
- Former state Senator Al Adams of Kotzebue;
- Carl Marrs, president and CEO of Cook Inlet Region, Inc., of Anchorage;
- Rosemarie Maher, president and CEO of Doyon, Ltd., of Fairbanks;
- Former state Natural Resources Commissioner Esther Wunnicke of Anchorage and a member of the public policy group Alaska Common Ground;
- Former Anchorage Mayor Jack Roderick, a noted Alaska author and oil industry historian;
- Oil and gas consultant Brian Davies of Anchorage and former vice president for BP in Alaska;
- Jim Jansen, President of Lynden transportation company in Anchorage;
- Former Permanent Fund Executive Director Dave Rose, currently president of Alaska Permanent Capital Management;
- Ed Rasmuson, chairman of the National Bank of Alaska;
- Lee Gorsuch, chancellor of the Universi Alaska Anchorage;
- Anchorage businessman Bob Penney, a member of the North Pacific Fisheries Management Council;
- Fairbanks North Star Borough Mayor Rhonda Boyles;
- Ron Duncan, president of GCI;
- Former ARCO Alaska President Ken Thompson, currently CEO of Pacific Rim Leadership Development of Anchorage;
- Peg Tileston of Anchorage, an environmental citizen activist and board chair of Alaska Common Ground, a non-partisan public policy group;
- Jake Adams, president of the Arctic Slope Regional Corporation
- North Slope Borough Mayor George Ahmaogak,

- Anchorage attorney Jeff Feldman;
- Jon Rubini, an Anchorage real estate businessman with statewide investments;
- Jerry Hood, chief executive officer of Alaska Teamsters Union local 959; and
- Mike O'Connor, president of Peak Oil Field Services Company.

"Commercialization of North Slope natural gas via the gasline project is the biggest economic opportunity to come to Alaska in years," Knowles said. "Taking full advantage of this opportunity won't be easy, though, and that's why we need a broad based, diverse group of Alaskans to work through the many issues that have to be addressed. I'm confident that this group will ensue public participation and produce recommendations that will protect the public's interests and make Alaskans proud as the gasline moves forward."

The Governor asked the council to hold statewide meetings to obtain the views of Alaskans on how the state can best promote a gas commercialization project and maximize benefits for Alaskans. He asked it to report back with recommendations by November 30, so their work can be incorporated into gas line legislation and project development. Among the issues the council will consider are:

- Benefits of natural gas development to Alaska communities, including those located in rural areas of Alaska;
- Best uses of the state's royalty share of the gas and promotion or attraction of investment for in-state and value-added processing;
- Costs and benefits of the state taking delivery of its royalty share of the gas in Alaska versus allowing a project developer to include the gas in its delivery flow to the Lower 48 states;
- Options for projects utilizing gas-to-liquids, liquified natural gas, and natural gas liquids;
- Demand for in-state natural gas consumption and its effects on a gas project;
- Environmental impacts and necessary protection measures;
- Training and readiness of Alaskans for jobs on a gas project, use of the Alaska labor pool by contractors and subcontractors, and use of Alaska businesses; and
- State promotion and facilitation of project financing, including potential ownership by the state of some or all of a project.

Two weeks ago, Knowles signed an administrative order that created a special Alaska Highway Natural Gas Pipeline Cabinet and directing state agencies to work aggressively for timely one-stop permitting and right-of-way preparation. Members of the Gas Pipeline Cabinet will serve as ex officio members of the council.

Knowles also recently introduced legislation that amends the "stranded gas" legislation that was passed in 1998 to facilitate natural gas commercialization to include an Alaska Highway natural gas pipeline or a gas-to-liquids (GTL) project.

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Alaska Highway Natural Gas Policy Council

COMMITTEE STRUCTURE

Council Mission: To promote an Alaska Highway Natural Gas Pipeline project to the lower 48 that also enables creation of a natural gas business in Alaska.

Alaska Hire/Buy/Build – Mike Navarre, chair
Jerry Hood, Rhonda Boyles, Jake Adams, Peg Tileston

- Use of the Alaska labor pool by contractors and subcontractors
- Use of Alaska businesses
- Training and readiness of Alaskans for jobs on a gas project
- Socio-economic impacts

State Pipeline Ownership and Tax Structure – Bill Corbus, chair
Dave Rose, Ron Duncan, Grace Schaible, Mike Navarre, Ed Rasmuson, Mike O'Connor, Ken Thompson

- State promotion and facilitation of project financing – state ownership
- Evaluation of state tax structure

Federal/International Action – Charlie Cole, chair
Esther Wunnicke, Bob Penney, Jon Rubini, Jeff Feldman, George Wuerch

- Federal permitting/access
- Federal agency lead
- Canadian permitting/access
- Other contractual considerations
- Domestic markets – competing sources/sharing of the market
- Canadian national and territorial relations

Access for In-State Gas Use and Future Opportunities – Ken Thompson, chair
Carl Marrs (vice chair), Rhonda Boyles, Al Adams, Brian Davies, Jim Jansen, Jerry Hood, Bob Penney, Jack Roderick, Lee Gorsuch, Jeff Feldman, George Ahmaogak, Bill Corbus

- Supply/demand for in-state natural gas
- Best practices valuation/netback pricing methodology to facilitate in-state gas use
- Ensuring fair and transparent access rules to natural gas for Alaskan customers
- Benefits of natural gas development to rural Alaska and to communities along the pipeline
- Future options over 50 years for projects utilizing: gas-to-liquids (GTLs), liquefied natural gas (LNG), natural gas liquids (NGLs), petrochemical feedstock, fertilizer, etc. for in-state use or for export to markets in Asia or the West Coast
- Promotion or attraction of investment for in-state distribution and value-added processing
- Assess costs and benefits of the State taking delivery of its royalty share vs. taking royalty payments; review other states' policies for best practices

Environmental Considerations – Peg Tileston, chair
Brian Davies, Esther Wunnicke, Lee Gorsuch, Grace Schaible

- Environmental impacts and necessary protection measures
- Doing it right

Section II:

Subcommittee Reports

Alaska Highway Natural Gas Policy Council

Committee Report
Alaska Hire/Buy/Build Committee
Mike Navarre, Chair

Recommendation:
The committee believes Alaska residents and contractors should be employed on a gasline project when they are available and qualified. In turn, contractors should be encouraged to employ and train Alaska residents.

Recommendation:
The committee believes that Alaska hire language, similar to language from the BP/ARCO Merger "Charter Commitment," should be sought for the Alaska Highway natural gas pipeline and facilities. *(Note: charter language is attached.)* It should be specifically stated that the quarterly report to the Department of Labor should include all contractors and subcontractors of the company or sponsor.

Recommendation:
The committee believes additional funding should be made available for vocational education training and should be coordinated with existing workforce training efforts now underway. Additionally, efforts should be increased to notify interested Alaskans of training opportunities available.

Recommendation:
The committee believes every effort should be made to ensure that needed gas production facilities are constructed at sites in Alaska.

Recommendation:
The committee recommends the State's Department of Community and Economic Development undertake a study to determine the socio-economic impacts of the gas pipeline along the Alaska Highway route. The Department has already begun implementation of this recommendation. A draft "scope of work" for this study is attached. We recommend the scope of the study also be expanded to include impacts to local governments.

Conclusions and narrative:
The committee held several hearings regarding the constitutionality of local hire laws. The record in Alaska on local hire litigation is not encouraging. We believe it will be difficult to construct local hire legislation that will withstand challenges under the U.S. and Alaska Constitutions (equal protection and privileges and immunities clauses). Additionally, a successful Alaska hire provision is complicated by the national and international scope of the project. Voluntary, cooperative efforts with industry seem to hold the most promise and should be pursued.

The number of jobs will be significant and will exceed the available capacity of Alaskan workers. The committee heard testimony that there is already a crisis situation being created because of the aging workforce in the oil industry, without factoring in the effect of a large-scale project like the gasline. There are coordinated efforts already underway, by industry, unions, native and tribal organizations, the Denali Commission, the University of Alaska and state agencies to address the training of Alaskan

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workers, and those efforts will require additional funding. The Alaska Human Resources Investment Council has developed a white paper that details a comprehensive approach to workforce training. It is attached as part of this report.

In addition to assuring labor stability, a project labor agreement will facilitate the further ramping up of union training programs, bringing more Alaskans into apprenticeship and skill upgrade programs. An ancillary benefit of the PLA is the legality of geographic preference provisions of collective bargaining agreements.

Committee members heard testimony from rural residents along the pipeline route expressing interest in job opportunities. We believe that issue is best addressed through notification, to interested Alaskans, of available training and through registering of interested workers and their skills. Construction training in rural Alaska has increased to an unprecedented level in the past two years through initiatives such as the Alaska Works Partnership, various labor organization programs, and the Denali Training Fund and other efforts funded by the Denali Commission. Continued support of these initiatives, which have resulted in training and employment of hundreds of rural Alaskans in construction, is essential if residents of communities along the pipeline and in areas of the state suffering economic dislocation due to fisheries problems, are to share in the economic benefits of the project. The Department of Community and Economic Development is already working with Native nonprofits to create accurate job banks, focusing on rural areas and villages.

The committee also obtained information regarding module related jobs for gas treatment facilities and compressors. The opportunity is tremendous and construction of modules, at Alaskan sites, should be vigorously pursued. It is estimated that the module related jobs and opportunities will be bigger than the Alpine, Northstar, Badami and MIX projects combined.

ALASKA HIRE COMMITMENT LANGUAGE
from BP/ARCO "Charter for Development of the Alaskan North Slope"
December 2, 1999

1. Alaska Hire Program.
BP and ARCO agree that, after the merger is completed, they will continue with and extend their commitment to the people of Alaska to utilize a voluntary program to employ residents of Alaska and to use Alaska businesses. It is expected by the parties that this program will include the attributes that:

a. BP and ARCO will comply with all valid federal, State and local hiring laws in hiring Alaska residents and contractors and will not discriminate against Alaska residents or contractors, and within the constraints of law will employ Alaska residents and contractors to the extent they are available and qualified;
b. When recruiting for new hires, BP and ARCO will advertise for available positions locally and use Alaska job service organizations to notify the Alaskan public;
c. BP and ARCO will use best efforts to contract with Alaska firms and fabricate modules in Alaska whenever feasible (in determining feasibility, BP and ARCO will consider commercial, health, safety, and environmental conditions and requirements to ensure maintenance of BP and ARCO's operational standards); and
d. BP and ARCO will, to the extent permitted by law, encourage its contractors to employ, and train when necessary, residents of Alaska.

2. Reporting.
BP and ARCO agree to submit to the Director, Division of Oil and Gas, for transmission to the Department of Labor, an annual report that details the specific measures that they and their contractors and subcontractors have taken or are planning to take to recruit qualified Alaska residents for available jobs, describes on-the-job training opportunities, and describes their efforts to use Alaska businesses for work in connection with their leases and associated activities. BP and ARCO will also furnish the Department of Labor a quarterly report regarding their employment of Alaska residents. The report will include statistical data concerning the number of resident personnel hired within the previous year.

3. Construction.
The program and reporting described in this paragraph are intended to be fully consistent with the 1996 amendments to paragraphs 41 (1980 leases) and 31 (1983 lease) of the Northstar Unit leases between the State and BP.

4. Alaska Native Recruitment, Training and Hire.
BP and ARCO further acknowledge their continuing support for the recruiting, training and hiring of Alaska Natives and the parties' common understanding of the desirability of providing Alaska's first citizens opportunities to participate in the economic benefits of oil and gas development, most of which takes place in rural Alaska.

Department of Community and Economic Development
Alaska Gas Pipeline Socio-Economic Impact Study
Scope of Work (DRAFT)

The Department of Community and Economic Development is currently undertaking a study to determine the socio and economic impact of the gas pipeline along the Alaska Highway route. There are currently two segments of the report. In order for the State of Alaska to anticipate future needs arising from the gas pipeline project, it will be necessary to look at both the positive and negative impacts associated with the construction and the operation.

Segment 1
The first segment is an analysis of the impacts to state departments (specifically DCED, DHSS, DNR, DOL, DPS, DOE). The Department is currently investigating this section internally. After completing a preliminary analysis of potential impacts to state agencies, the report will be disseminated amongst the agencies so that the departments can tailor more specific questions that will need to be addressed.

Segment 2
The second segment is the potential economic benefits the gas pipeline would have for the State of Alaska and perhaps in more detail the communities along the proposed Alaska Highway route. An independent third party contractor will investigate this segment.

It would identify potential economic opportunities created by the gas pipeline along the highway route during construction and also during the operational phase. For the construction phase, the study would examine past pipeline projects to see which sectors benefited from the construction activities as well as what types of business developed in the region during the construction phase.

The study would also include an analysis of what types of businesses might expand or relocate to Alaska as a result of accessibility to a large supply of natural gas. These projects might include a petrochemical facility, an increase in mining activity, and transportation infrastructure. Other benefits that could be examined include the potential for cheaper utilities to rural areas as well as an increase to the local tax base for communities along the pipeline.

Once the scope of work can be finalized, an RFP will be created based on the finalized scope of work.

DRAFT

Alaska's Skilled Worker Shortage: Crisis or Opportunity?

A White Paper for the
Alaska Human Resource Investment Council

August 9, 2001

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Introduction

> The future looks bright for Alaska, but do we have the people to fill the jobs? The oil and gas industry wants to fill positions to support a new gasline. Will those employees come from out of state? They'll have to if we don't have a trained workforce in Alaska to fill the good jobs. The same goes for teachers, pilots, nurses, truck drivers. Our only hope is training. But no one entity can do it alone. Industry must partner with education. Unions must work with vocational schools. Partnerships, incentives and education are the key.—*Lt. Governor Fran Ulmer*

Over the last two years the Alaska Human Resource Investment Council (AHRIC) has become increasingly concerned about the lack of a skilled workforce in Alaska. Members of the AHRIC believe the state is on the verge of a workforce crisis, describing the situation as "urgent," "serious," and "critical." But members of the AHRIC also believe the labor shortage presents tremendous opportunities for Alaskans who are unemployed or who lack education and training. As the "...private/public leadership board that sets the policy framework for developing Alaska's workforce," members of the AHRIC call attention to Alaska's workforce issues. Planning efforts today will have a direct impact on Alaska's ability to attract new businesses, maintain an educated workforce and build and sustain projects such as the much-desired natural gas pipeline.

Workforce Concerns

A natural gas pipeline from the North Slope to the lower 48 has become more of a reality with the rising price of petroleum products. A national missile defense project based in Alaska is being discussed in Congress. Commercial construction activity is healthy in Anchorage, with two multi-story office buildings under construction and a 23-story multi-use facility in the planning phase. Visions of an economic expansion are tempered, however, by the fact that Alaska may not be able to supply enough trained workers. A recent Associate Press article states:

> The oil patch is bustling around the country, so Alaska is competing with the Lower 48 states and elsewhere for engineers, pipefitters, drilling workers and more to find and develop new oil reservoirs.... *Allen Baker, The Associated Press, April 17, 2001*

In addition to the lack of skilled workers, many of Alaska's trained workforce are on the verge of retirement. Add to that predicament the fact that there has been a decline in the number of younger Alaskans:

> The number of Alaskans age 20 to 34 has declined significantly in total numbers (by about 36,000) since the 1990 census....Just as a disproportionately large number of Alaskans approach retirement age there will be relatively few Alaskans that will have completed postsecondary education or training needed to fill the openings created by retiring workers.
>
> —*Alaska Economic Trends, September 2000*

The oil and gas industry has one of the highest percentages of workers over the age of 50; in 1999 the average age of a pipeline worker was 47. In addition, the average age of electricians, operating engi-

neers, institutional cooks, mechanics, heavy equipment mechanics, engineers, civil engineers, and workers in heavy construction is 40 or over.

The need for trained workers extends well beyond the construction trades. Like the rest of the nation, Alaska is desperate for health care and information technology workers. There is a shortage of teachers in rural areas of the state, especially Alaska Native teachers. With regard to employer demand, the health care industry has the highest need for workers; of the 15 fastest-growing occupations, ten are associated with health services, three with information technology and two with the transportation/visitor industries.

In order to attract and keep businesses in Alaska, it is necessary to have good schools, a business-friendly environment and basic infrastructure. We can't have good schools without good teachers. A business-friendly environment is impossible without educated, trained workers. Basic infrastructure cannot be built without skilled labor. Alaska's workforce is the common denominator that makes economic development possible.

Defining Workforce Priorities

> We've been here before; we know what happened when Prudhoe Bay came online. We didn't have enough Alaskans to fill the jobs and we imported a lot of labor from Outside. Let's not revisit the past. We have an excellent opportunity to train Alaskans. Let's make sure Alaskans are the first to benefit from the next big project. — Ed Flanagan, Commissioner, Alaska Dept. of Labor and Workforce Development

The AHRIC has already laid the groundwork to prioritize Alaska's workforce development needs. In response to legislation passed during the 2000 legislative session, an annual priority list for Alaska Technical and Vocational Education Program grants was developed. The construction, health care, information technology and transportation industries have been targeted, based on economic, employment and other relevant data developed to maximize employment opportunities for participants. Federal and state training dollars will now be awarded in alignment with the priority list.

Opportunities & Workforce Gaps

The Alaska Department of Labor's Research and Analysis (R&A) Section has extensively researched employment needs in the state and has identified lists of "hot" and "best-bet" occupations. "Hot" occupations are jobs with a higher than average projected growth rate and a higher than average estimated wage, and "best-bet" occupations are those with good employment opportunities and good wages. The R&A Section's statistics show that twenty-seven of the forty-one "best bet" occupations require education or training of an associate's degree or higher. There are a number of "hot" occupations, however, that do not require university degrees. Research and Analysis notes:

> The labor trades and crafts occupations of electricians, plumbers, electrical powerline installers/repairers, excavating and loading machine operators, and operating engineers all combine growing employment numbers with estimated earnings in the highest earnings group. The often rigorous training required for these occupations is generally available 'on-the-job.'

In addition, state labor economist Neal Fried has seen a shift in the state's population. "It's a tighter labor market and there's more turnover. There are more people leaving the state than entering," Fried said. As a result, there are more opportunities in Alaska for young people and unemployed workers than in the recent past. "The markets have been very healthy and the opportunities have been extraordinary for Alaskans who try to take advantage of it. Kids have many more opportunities than in the past if they know what's out there," Fried said.

A Call to Action

Are there enough workers in Alaska to build a large construction project? Will Alaska seniors suffer because there are too few health care workers to care for them? Will Alaska children receive a substandard education because certified teachers cannot be recruited? Will opportunities to expand Alaska businesses vanish because there are no information technology workers?

At this point, the answers to such questions are unclear. Many pieces are in place for Alaska's successful transition to a trained, skilled workforce, but more remains to be done. Governor Knowles and Lt. Governor Ulmer have made workforce development a high priority as evidenced by the creation of the Alaska Human Resource Investment Council (AHRIC), the Governor's Jobs Cabinet and the increased funding for the FY 2002 education budget. U.S. Senator Ted Stevens expressed concern over Alaska's lack of focus on vocational education, and the AHRIC responded with a state plan for vocational training, "*Alaska's Future Workforce Strategic Policies and Investment Blueprint.*" Proposals for regional training centers in geographic hubs have been evaluated and may be funded through efforts by Senator Stevens. State industries and business groups have set up formal consortia with educational institutions to develop curricula and focus on workforce needs. The Department of Labor and Workforce Development has initiated an effort to actively promote its job training and employment services and has developed a partnership with the Denali Commission, an organization that also provides job training opportunities.

In spite of current efforts toward solving the workforce crisis, state policymakers continue to be concerned. What must be done to produce a viable workforce to ensure future economic development in Alaska?

- Financial Support. The State of Alaska must increase aid to academic and vocational educational programs. Economic development will not happen without a workforce that has access to good educational opportunities.

- Help Students Succeed. State student loans are readily available, but the cost of a college education has increased exponentially over the years. A student graduating from college or vocational school is immediately faced with loan payments on the level of a car or house payment. The state can do more to encourage students to pursue a higher education by providing financial incentives for job training and postsecondary education in priority occupation areas; incentives should be geared toward encouraging students to remain in Alaska upon completion of their training or degree. The state can also encourage student success by providing adequate funding for:
  - early childhood education;
  - career education awareness and linkages, K-14; and
  - distance delivery of education to rural areas.

- Vocational education is key to training the number of workers who will be needed for all types of construction projects. Associated General Contractor's Dick Cattanach expresses the concern well:

> This year there were 6,900 high school graduates [in Alaska]. Of those, 70 percent don't go to college....When I went to high school, kids took shop, woodworking; we don't have that anymore. We don't seem to emphasize the vocational track anymore. We emphasize the college track and we ignore 70 percent of the kids who graduate. We're not doing nearly enough. Voc ed is an afterthought—we're not focusing on the future of our kids.—*Dick Cattanach, AGC*

If we want trained workers for the future, Alaska's legislators and other key policymakers must commit to funding vocational education programs at a level that reflects the huge number of students who will not go on to advanced education. We must focus on "the other 70 percent."

- Workforce Development Clearinghouse. Creation of a web-based clearinghouse is necessary to provide access to essential functions of the workforce development system. Information is currently available through federal, state and local sources, but a central hub is necessary to manage information in a coordinated manner. The clearinghouse would include information regarding:
  - employment, training and labor market information;
  - professional development, technical assistance and capacity-building services;
  - budget review that promotes alignment and leveraging of resources.

- Reauthorization of the State Training & Employment Program (STEP) as a permanent program. STEP is an innovative job-training program created in 1988 and funded by one tenth of one percent of employee contributions to the Unemployment Insurance (UI) Trust Fund (no state general funds are used). STEP's purpose is to reduce current and future claims against UI benefits by training residents who are unemployed, underemployed or are about to lose their job. Although STEP has been reauthorized each time it has come up for sunset review, making STEP a permanent program in 2002 would signal a commitment by state leaders to train workers who might otherwise join the unemployment rolls.

- Strengthen and Secure AHRIC's Oversight Role. The Alaska Human Resource Investment Council has made significant strides in its first six years, but the AHRIC's oversight role must be strengthened to bring all Alaska education and training providers and workforce programs under one umbrella. The AHRIC is the oversight body that can make sure Alaskans are being trained for the right jobs and are meeting the needs of Alaska employers.

A Shared Vision

Alaska will have enough workers to build a pipeline, Alaska's seniors will be cared for, our children will receive an excellent education and business opportunities will abound if business, industry, government, the university and state policy makers join forces to make workforce development a top priority. We must plan now for tomorrow's workforce. If we fail to act, the opportunities we see on the horizon will become tomorrow's workforce crisis.

Alaska Highway Natural Gas Policy Council

Committee Report

State Pipeline Ownership and Tax Structure Committee

Bill Corbus, Chair

Recommendation:

The committee believes the pipeline is economically feasible for certain investors and should be undertaken with private financing. We recommend against direct State investment unless there is clear evidence of economic benefits to Alaska that cannot be achieved through other regulatory or political mechanisms.

Recommendation:

The committee encourages exploration of creative financial structures to facilitate all or part of a gas pipeline and/or in-state gas infrastructure, provided such entities finance their activities through private markets.

Recommendation:

The committee recognizes that State tax policy is one of several tools that could play a role in influencing pipeline development, but reserves a decision. It is premature to decide how to use this tool until there is more definition of a project and the nature of its ownership.

Conclusions:

* When the committee began its work early in 2001, there appeared to be certain problems that could be resolved by partial State ownership in a gas pipeline, and that it could be an important advantage for Alaska. However, through the process of gathering information and holding meetings, the committee has determined that most if not all of these could be resolved through other means, other tools the State has at its disposal. For example, access to and from a pipeline can be facilitated through the State Regulatory Commission of Alaska working with the Federal Energy Regulatory Commission, and through stipulations in a State right-of-way lease across state lands.

* The committee believes a natural gas pipeline from Alaska would be a good investment, but there are other, equally good investment opportunities for public funds that entail less risk. The State has a policy of diversifying investment of its assets (the Permanent Fund is an example) to reduce risk.

* From information gathered during hearings, the committee has concluded that, absent majority or total ownership of a natural gas pipeline, an ownership interest gives the State no right to capacity in the pipeline. Capacity in a contract carrier pipeline is obtained through the nomination process during an "open season."

* The committee is not persuaded that partial ownership of the pipeline raises any conflict of interests for the State (i.e. a State "ownership" interest vs. a State responsibility to regulate the pipeline) that cannot be resolved.

* The committee investigated alternative sources of financing, including the Permanent Fund, Constitutional Budget Reserve and the ability of various public authorities to issue revenue bonds. The committee believes that private sector companies can raise needed funds based on adequate coverage and financing reserves. State participation would not enhance the acquisition of funds, would not necessarily guarantee lower financing costs and might unduly interfere with a straightforward private sector funding. The State's participation would include a vote on a tariff, but its interest would not be proportionately large and it would not guarantee a desired outcome.

* Absent a compelling public interest for partial State ownership, ownership of the pipeline is best left to private industry and to firms which are experienced in oil and gas and the pipeline business.

* The committee suggests that Alaskan-owned businesses, such as Alaska Native corporations, have the opportunity to invest in a natural gas pipeline project.

* Regarding alternative financing mechanisms, the committee has been told by the producers' group that an investment in a gas pipeline might not meet the rate-of-return criteria for the producing companies. If so, alternative financing mechanisms, such as through a public authority, might facilitate others, such as pipeline transmission companies, becoming involved. A public authority may have advantages in terms of exemption from federal income tax, or jurisdiction by the Federal Energy Regulatory Commission.

* Regarding tax policy, the producers are seeking simplification and clarity in natural gas tax and royalty administration.

* The Gas Policy Council itself has endorsed the Governor's proposals for federal tax incentives, such as accelerated depreciation, an investment tax credit and a gas price volatility protection mechanism, a tax credit that becomes effective if prices fall below a certain point. The committee reaffirms this endorsement.

* The committee feels that if a viable proposal for a pipeline is put forward and the producers do not respond in a reasonable period of time, the State should use the tools that it has available to facilitate the project moving forward.

* The committee recommends finding a mechanism for a "contract" between the State and a sponsor of a gas pipeline project that would encourage a State fiscal policy as well as a stable State revenue policy. While there are legal limits to the Legislature's ability to guarantee future tax policy, such a contract would carry an important moral commitment and would be worthy of consideration for an Alaska Highway gas pipeline.

* Different forms of pipeline ownership will affect the interests, and incentives, of the parties involved. Overall, the State has an interest in keeping costs of a pipeline down, and transportation tariffs lower, to maximize State revenues. (State revenues are based on the "wellhead" values of gas on the North Slope, after transportation.) If the producers build the pipeline, they will have an interest in maximizing production revenues, similar to the State, but will have less interest in keeping tariffs low because they are also pipeline owners. If an independent pipeline company consortium owns the pipeline, the producers' interests will be only in maximizing production revenues. In that scenario, the producers' interests would be aligned with the State's in seeking low tariffs for transportation of gas.

Alaska Highway Natural Gas Policy Council

Committee Report
Federal/International Action Committee
Charlie Cole, Chair

Introduction

Members of the Gas Policy Council were extensively involved in decisions on State policy and in the development of proposed legislative changes. A substantial product of the Federal/International Action Committee were recommendations for changes to federal law to address key concerns of the State of Alaska in the development of a natural gas pipeline.

The committee supports modifications to modernize Alaska Natural Gas Transportation Act (ANGTA) and believes such modifications would be beneficial to an Alaska gasline project. The committee endorsed ten key policy goals that should be included in any new gasline legislation.

The ten policy goals developed to guide drafting of the legislation were debated by the full Council and ratified in concept by a majority of its members on September 25, 2001. Several changes were made as a result of points raised by Council members during the September 25 debate.

If Congress moves forward with new legislation as suggested by the producers, a principal concern of the Council is that Congress should take steps early to reaffirm the southern, or Alaska Highway, route as the sanctioned route for a natural gas pipeline, as a previous Congress did in 1977 when it ratified the President's choice of the southern route under ANGTA. Such a step would focus the attention of industry and federal agencies on regulatory and permit approvals for a project along this route.

This committee also notes that a southern route provides several advantages over other alternatives. Among these is use of the pipeline corridor for other purposes, including the possibility of constructing a railroad or other utilities over time. In addition, a southern route could facilitate access to highly mineralized areas which are located in close proximity.

A second concern of the Council was the probability that with a new initiative in Congress, an Alaska gas pipeline would be subject to Federal Energy Regulatory Commission (FERC) jurisdiction on issues important to Alaska without a defined role for the State with FERC. Such issues would include tariffs on intra-state shipment of gas, and access to and from a pipeline. The proposal for a joint board that would give the Regulatory Commission of Alaska (RCA) joint jurisdiction with FERC on issues affecting Alaska grew out of this concern.

Other concerns of the Council involved provisions to encourage hiring of residents of Alaska for a gas pipeline project, and the hiring of Alaskan Natives.

It was recognized by the Council that the pipeline project will be substantial and that, for all practical purposes, qualified Alaskan workers wishing to work on the project will be employed. Still, an explicit encouragement to hire locally will be a strong inducement for companies and unions to train Alaskans

for pipeline-related construction and operating jobs. The skills developed in the Alaskan workforce as a result of training and employment will thus be a lasting legacy of the project.

The Council also considered the importance of pipeline access and the need for future open seasons to facilitate pipeline access for new discoveries. Failure to provide for additional capacity either at startup or through future open seasons could create a "monopoly" on pipeline capacity, discouraging exploration by non-owners. Any new gasline legislation must address this issue to protect the interests of the State of Alaska.

Other policy points guiding development of proposed legislation are detailed later in this report.

The committee recognizes the Governor's strong advocacy of the 10 principles, as reflected in his recent testimony before the Senate Committee on Energy and Natural Resources and in other forums. It would appear that the State's policy position is well understood by decision makers in Congress and the Federal Executive Branch.

With this in mind, the committee believes that it would be useful for the State Administration to continue its efforts with the commercial parties to develop a market driven solution to transport Alaska natural gas to market via the Alaska Highway route.

Close coordination and communication between the State, the North Slope producers and the pipeline companies could facilitate the establishment of a consortium of companies with the financial capability to build the pipeline.

In our opinion, current discussions among the parties concerning economic feasibility and reestablishment of the previous pipeline partnership underscore the need for such coordination at this time.

Background on ANGTA

Congress enacted the Alaska Natural Gas Transportation Act (ANGTA) in October 1976, after finding that the national interest called for the expeditious construction of a transportation system to bring Alaska natural gas to markets in the lower 48 states. The primary goal of ANGTA was to "provide the means for making a sound decision as to the selection of a transportation system . . . by providing for participation of the President and Congress in the selection process, and . . . to expedite its construction."[1]

To achieve that goal, the Federal Power Commission (the precursor to the Federal Energy Regulatory Commission (FERC)), held hearings and prepared a "Recommendation to the President," which recommended two possible overland routes through Alaska and Canada. The President then selected the southern route, the Alaska Natural Gas Transportation System (ANGTS), as the preferred alternative. Congress approved the President's selection by a joint resolution in November 1977.

ANGTA establishes the framework under which federal agencies (including the FERC) are to review and approve the ANGTS project. ANGTA supplements, but does not supersede, the Natural Gas Act

– which is the law that normally governs approval of natural gas pipelines, and requires a certificate of public convenience and necessity before interstate natural gas pipelines are built.

However, because ANGTA was designed to expedite construction of an Alaska gas pipeline, it contains numerous provisions that speed up administrative and judicial review. For example, ANGTA directs that any applications under it shall take precedence over similar applications and shall be expedited by federal agencies.[2] ANGTA also provides that a Federal Inspector be appointed to coordinate all federal activities and enforce federal requirements.[3]

In addition, ANGTA contains provisions dealing specifically with access to facilities and in-state access to gas. ANGTA provides that there shall be no discrimination against any shippers based on the degree of ownership in the system. It also provides that the State of Alaska is authorized to ship its royalty gas on the system and withdraw its gas for use within Alaska.[4]

Finally, ANGTA limits judicial review of any agency action to issues of whether the agency violated constitutional rights or statutory authority – effectively limiting the scope of environmental challenges to a project constructed under ANGTA.[5]

Because the Alaska segment of the project has not been constructed under ANGTA since its enactment 25 years ago, there may be outstanding issues regarding its current application. For example, the creation of legislatively designated areas—such as parks or wildlife refuges—may require re-routing portions of the project. This raises the question whether the project approved by the President has been altered so substantially as to render the findings in ANGTA ineffective. In addition, a competing project may be proposed under the Natural Gas Act, raising the issue of whether the preferential treatment required under ANGTA has already been provided, or whether an ANGTA project must be constructed before any other project designed to bring Alaska gas to the lower 48 states can be approved.

Summary of the "Alaska Natural Gas Pipeline Act of 2001"

The "Alaska Natural Gas Pipeline Act of 2001," set forth by the Alaska Gas Producers Pipeline Team, provides a streamlined administrative process and limited judicial review for non-ANGTA gasline projects. The legislation is designed to eliminate outstanding legal issues regarding whether non-ANGTA gasline projects may proceed absent the repeal of ANGTA.

Section 2 of the bill, "Congressional Findings," states that it is in the national interest to provide "as much regulatory certainty and expedition as practicable" for approval of one or more pipeline systems from Alaska to the lower 48.

Section 3 of the bill, "Congressional Purpose," states that the purpose of the bill is to expedite federal decision making, create an Office of the Federal Pipeline Director to coordinate federal agency decisions, and expedite and limit judicial review concerning both the Act and the approval process for any Alaska gasline project.

The bill defines "Alaska Facilities Gas Project" to mean any natural gas pipeline system that carries Alaska gas to the lower 48. It does not specify a preferred route.

Section 5 of the bill amends the Natural Gas Act to set out an expedited approval process for an Alaska gasline. It directs the Federal Energy Regulatory Commission (FERC) to issue approval within 18 months of an application if: there is an agreement to ship with a party that controls Alaska natural gas; rates can be established according to FERC's usual procedures; and if there is compliance with all environmental laws.

The bill states that the lead agency for preparing an environmental impact statement (EIS) shall be FERC, and that the EIS process shall be expedited and the final EIS issued within 18 months after an application is filed.

Section 7 of the bill establishes the Office of the Federal Pipeline Director. This office appears to have a function analogous to the Office of the Federal Inspector, created under ANGTA. The Federal Pipeline Director will coordinate all federal activities related to the pipeline project. It will be a "one window point" for filing and issuing all necessary permits and is responsible for coordinating and expeditiously completing all environmental reviews and studies.

The bill directs federal agencies to coordinate and expedite review of the gasline project and gives the Federal Pipeline Director the authority to remove discretionary requirements from federal permits if they would impair or prevent the expeditious construction of the pipeline.

Section 9 of the bill limits judicial review to claims challenging the Act itself, constitutional claims or claims that an agency is acting outside of its jurisdiction. Lawsuits must be brought within a shortened time frame, with jurisdiction in the U.S. Court of Appeals for the District of Columbia.

Section 10 provides that, if any provisions of the Act are invalidated, the remainder of the provisions will be unaffected.

Background on Canadian relations

First Nations

The Kaska First Nations located in Northern British Columbia and the Yukon continue to negotiate land claims and self-government agreements with the Government of Canada and the Province of British Columbia. While these negotiations are expected to continue for the foreseeable future, speculation is that when the time is right, the Kaska will be open to a side agreement on any proposed pipeline running through their territory.

The eight First Nations who have land claims along the proposed route of the Mackenzie Valley pipeline have been negotiating with producers since late spring of 2001. Early in October of 2001, seven of the eight groups came to an agreement on ownership sharing of any pipeline built through their territories. This agreement would grant 30% ownership to the First Nations Bands. The eighth, the De Cho, refuse to sign the agreement. While the Minister of Indian Affairs and Northern Development has been quoted as saying that one Band cannot hold a veto over any project, the De Cho believe that they have the right to refuse construction on lands they claim.

Position of the Government of Canada on Arctic Gas Production and Transportation
The Government of Canada has affirmed that in relation to this project, all departments and agencies will maintain route and project neutrality. In the spring of 2001, the Prime Minister set up a Cabinet reference group to study the current state of Canada's energy policy. The main issue of study was whether to express a preference for one route over another. A number of Cabinet Ministers expressed support for either the "over-the-top" route or a two-pipeline route with the construction of the Mackenzie Valley line happening first. After careful consideration of all available information and a careful review of the regulatory implications of each option, the Cabinet reference group recommended to the Prime Minister that the original position of route and project neutrality be maintained.

Provincial and Territorial Positions
Of the four non-federal jurisdictions involved in the issue, only the Yukon Territory is firmly supporting the Alaska Highway route. While they have not been overly aggressive in the past, they intend to become more aggressive in promoting the route with the Canadian Federal Government. The Yukon Government has commissioned an economic study of the benefits to Canada of constructing and operating the Alaska Highway route, and it is expected that this study will be released to the public in January of 2002.

The Northwest Territories is aggressively promoting the Mackenzie Valley line either in conjunction with an over-the-top segment or as a stand-alone line. Assuming the latter is chosen by producers, the Northwest Territories is demanding that this line be built before an Alaska Highway gasline. They are very active with the Federal Government, asking for financial incentives to ensure the line's construction.

The other two jurisdictions involved, British Columbia and Alberta, have remained route and project neutral. Premier Klein of Alberta has said that regardless of what line is built, he will not allow a "bullet line" to cross his province. He demands that Albertans share in the long term economic prosperity created by a line to the lower United States. Principally, he is referring to gas liquids and would like to see the petrochemical industry in his province benefit from them.

While it would seem logical for the government of British Columbia to be supportive of the Alaska Highway route, this government has only been in power since June 2001, and this issue has yet to be critically examined by the Premier and his Cabinet.

Recommendations

The committee endorsed 10 key policy goals that should be given consideration in any new federal gasline legislation. The 10 principles and corresponding legislative provisions are outlined below.

Key Principles
1. Find that the Alaska Highway natural gas pipeline is in the national interest.
2. Mandate the already permitted Alaska Highway route as the preferred route.
3. Provide opportunities for new pipeline participants, such as existing producers, pipeline companies and major Alaska companies.

Corresponding Legislative Provisions

- The 1976 Alaska Natural Gas Transportation Act (ANGTA) that established a process selecting the ANGTS project following the Trans-Alaska Pipeline and the Alaska Highway through Canada to the lower 48 should be the framework for any new gasline legislation.
- The legislation should provide for updating and modernizing the process provided in ANGTA for the expeditious environmental review and approval of a pipeline application for the Alaska Highway route.
- A finding that an Alaska Highway route would make an important long-term contribution to the nation's energy supplies and independence.
- A finding that an Alaska Highway route would have less potential environmental impacts and related delays in construction.

Key Principles

4. Provide a mechanism for Alaska communities and businesses to obtain access to natural gas from the pipeline.

Corresponding Legislative Provisions

- FERC should require the project sponsor to demonstrate how the sponsor plans to meet reasonable projections of in-state local consumption needs, including the needs of Fairbanks, Cook Inlet and rural Alaska. In addition, the sponsor should allow for possible future construction of a pipeline to tidewater for the export of LNG.
- The Regulatory Commission of Alaska should have concurrent jurisdiction with FERC to set just and reasonable rates for the shipment of natural gas over the Alaska section of the gasline for in-state users.
- The Regulatory Commission of Alaska should have exclusive jurisdiction to set just and reasonable rates for any lateral pipeline connected to the Alaska section of the gasline that serves in-state users.

Key Principles

5. Provide access to the pipeline for new natural gas discoveries that will keep Alaska's oil and gas industry healthy through new leasing, exploration and production.

Corresponding Legislative Provisions

- FERC should require the project to establish reasonable plans and procedures, including additional open seasons if necessary, for the expansion of the Alaska section of the gasline as new fields of natural gas are developed on the North Slope and throughout Alaska.
- FERC should be authorized to order expansions of the gasline in the future under reasonable, non-discriminatory terms.

Key Principles

6. Provide for Alaska hire and Alaska Native hire.
7. Provide for the use of Alaska businesses.

Corresponding Legislative Provisions

- To the extent allowed by law, Alaska residents and contractors should be employed when they are available and qualified. In turn, contractors should be encouraged to employ and train Alaska residents.

- Recruitment should be accomplished primarily by advertising in-state and using Alaska's job service organizations to notify the Alaskan public.
- The project sponsors must, whenever feasible, enter into construction contracts with Alaska firms and fabricate modules in Alaska.
- The gasline sponsors should be required to enter into an agreement to provide for pre-employment recruitment, on-the-job training, and employment of Alaska Natives.

Key Principles

8. Provide for a project labor agreement for the construction and maintenance of the pipeline, and for worker training.

Corresponding Legislative Provisions

- The project labor agreement should require all contractors and employees to agree to a total ban on strikes, lock-outs and other disruptive activities for the life of the agreement.
- The agreement should be designed to ensure a steady supply of skilled labor and a contractually binding means of resolving worker grievances.

Key Principles

9. Provide a priority for the use of American and Canadian steel.

Corresponding Legislative Provisions

- Only steel manufactured or produced in the U.S. or Canada should be used in the construction of the Alaska section of the gasline unless its use is inconsistent with the public interest or the cost is unreasonable. Factors to be considered in evaluating the public interest should include quality, availability and delivery times.

Key Principles

10. Provide for economic incentives to give investors in ANGTS additional levels of confidence.

Corresponding Legislative Provisions

- Accelerated depreciation on gasline investments.
- An investment tax credit for an approved ANGTS project.
- A tax credit for producing gas from the Alaska North Slope tied to a price floor.

Footnotes

[1] 15 U.S.C. § 719a.

[2] 15 U.S.C. § 719g.

[3] This provision was repealed in 1992. Pub. L. 102-486, Title XXX § 3012(a), Oct. 24, 1992, 106 Stat. 3128.

[4] 15 U.S.C. § 719k.

[5] 15 U.S.C. § 719h.

Alaska Highway Natural Gas Policy Council

Committee Report

Access for In-State Gas Use and Future Opportunities Committee

Ken Thompson, Chair

Purpose: The Access for In-state Gas Use and Future Opportunities Committee will address key issues and make recommendations on state policies to enable fair and transparent pipeline access for in-state gas use and for the creation of a broader natural gas business within Alaska upon commercialization of North Slope gas.

Goal #1: Assess current supply/demand for in-state natural gas use and assess potential demand for expansion of current use as well as conceptual new uses.

Recommendation:
A long-term clean energy plan and vision needs to be developed for Alaska, providing for substantially increased use of natural gas for residential and industrial use and for power generation.

Recommendation:
The State should take a long-term, broad and strategic view of its entire natural gas resources. This should include areas on the North Slope, including non-producing areas, Interior basins and in south Alaska. There is a significant potential gas resource base in Alaska much larger than the 35 tcf proven natural gas reserves in existing fields on the North Slope.

Recommendation:
The State of Alaska should undertake more intensive, updated geologic and geophysical studies of the natural gas potential of current non-producing areas, including Interior and Southcentral Alaska basins. This should include a more thorough assessment of basin geology and natural gas generation and migration utilizing the most modern technology tools, as well as a more thorough assessment of the producible methane gas potential from coal seams within Alaska. In recent years new tools, such as satellite imagery and soil sampling techniques, have been developed. Another gas resource that should be assessed is gas from gas hydrates on the North Slope and in Interior basins, which are very sizeable and could be developed in future decades as technology advances.

Recommendation:
The State should evaluate incentives and policies to spur the exploration by private companies for natural gas, to better delineate the natural gas resources not only on the North Slope but elsewhere throughout the State. Strategies and plans should be implemented to attract additional companies interested in natural gas exploration who now utilize new technologies, to the North Slope, Cook Inlet, the Interior basins and elsewhere in the state.

Recommendation:
A major gas pipeline should traverse Alaska if the State is to fully exploit its longer-term resources from all basins over 50-plus years and also to gain access to future multiple markets over the long-term. In addition such a pipeline could ensure long-term, reasonably priced supplies of energy to the Railbelt and other areas of the State thereby encouraging economic development.

Recommendation:

The State should facilitate favorable policies and incentives to encourage development by the private sector of a broader natural gas infrastructure within the State that meets the long-term clean energy demand of Alaskans at reasonable market prices.

Conclusions:

* Natural gas supply in Southcentral Alaska is decreasing while demand for natural gas in home and commercial use as well as for electrical generation is increasing. Additional reserves of natural gas will be needed to meet future demand.

* The natural gas demand in Southcentral Alaska in 1998 was 589 million cubic feet per day (mmcfd) and is estimated to have grown 1 - 2.5% per year over more than 30 years. Approximately 166 mmcfd is used for local utilities, 75 mmcfd for residential and commercial space heating use and 91 mmcfd for electric power generation. Three hundred-sixty mmcfd is for industrial use, 214 mmcfd for LNG export and 147 mmcfd for ammonia-urea manufacturing. Forty-six mmcfd is for fuel to operate oil and gas production facilities.

* Unless new significant gas reserves are developed, a shortfall in natural gas deliverability for peak winter demand is predicted for Southcentral Alaska by 2006-08. This deliverability shortfall may be offset by gas storage, by curtailment of industrial use or by bringing new reserves on line. However, replacement of the deliverability will add higher cost resources, substantially increasing natural gas and electricity bills for consumers and businesses in Fairbanks, Anchorage, the Mat-Su Valley and the Kenai Peninsula.

* By 2009 without significant new sources of gas, the continued operation of the LNG plant and/or the ammonia/fertilizer plant is at risk. The export license for the Kenai LNG facility expires in 2009. It is conceivable that the export of LNG would not be authorized beyond 2009, and rising gas prices may make it difficult for the ammonia–urea plant to compete in international markets.

*In the long term, conventional natural gas (excluding coal bed methane) in Cook Inlet will probably be unable to meet the needs of the Cook Inlet region even with the cessation of all industrial uses. A long-term solution to this pronounced shortfall in deliverability would be gas from the North Slope. Depending on the delivered price of North Slope gas, this may also allow the continued operation of the industrial plants, thereby saving over a thousand total jobs and maintaining property taxes and State revenues.

* By 2018, Southcentral Alaska may have to rely on other fuel alternatives: heating oil and coal. In the case of fuel oil and coal, there are clean air environmental consequences for citizens in Anchorage, the Mat-Su Valley and on the Kenai Peninsula.

* Current natural gas purchases by residential and commercial users in the Anchorage area total over $100 million per year. The deliverability shortfalls starting as early as 2006 could cause natural gas prices to increase, affecting business growth and corporate taxes to the State as well as affecting cost of living for residents.

* The most competitively priced and cleanest fuel for consumers in Fairbanks may be North Slope gas that can be delivered to the Fairbanks area through an offtake "hub" or tap in the main gas pipeline.

* Along the pipeline route from the North Slope through Interior Alaska, 14 large mineral prospects have been identified within 20 miles of the gas pipeline corridor. These mineral prospects are currently not economic, with the largest cost for development being energy cost. Testimony was given that some of these mineral prospects may be commercially viable if a reasonably priced natural gas supply was available.

* The natural gas resources in Interior basins and in South Alaska have not been fully explored and delineated, but earlier screening studies have indicated the presence of natural gas. Little exploration or development has taken place because of lack of transportation to market and perceived geologic risk. In some areas, very little is known about basin geology and natural gas generation and migration, yet natural gas has been recognized as present.

* Alaska has the United States' largest volume of coal beds, but little work has been done to quantify the methane gas potential from coal seams. In the lower 48 over the past fifteen years coal seam gas production has become a major supply source near locales where pipeline transportation is available.

* Potential reserves of methane gas trapped as gas hydrates in shallower geologic formations on the North Slope or in Interior basins could be very large. Recent studies in the lower 48 and Canada indicate trillions of cubic feet of entrapped natural gas as hydrates. Numerous research and technology studies are underway by the Department of Energy and private companies to better assess the gas hydrate resource base and technologies needed to commercialize this huge resource in the future. Alaska needs to better quantify its very large gas hydrate resource base on the North Slope and in other basins of Alaska, and to stay abreast of technology improvements.

* Interestingly, exploration companies new to Alaska such as Forest Oil, Andex Resources, Lappi Resources, Evergreen Resources and others have shown interest in the Interior basins for conventional gas exploration using new technologies and for coalbed methane. Four new exploration licenses totaling 4.8 million acres are underway as well as more extensive leasing of coalbed methane leases. This new exploration should continue to be encouraged through favorable State policies and incentives. If these gas resources prove to be of large size over the next 50 years, a pipeline option that offers access to markets outside the State will be necessary as in-state markets are somewhat limited in size.

* There is not a long-range energy plan for the State that positions for the marketing of natural gas from different basins, including the prolific North Slope. A pipeline traversing Alaska offers the best option to allow assessment and future marketing from all basins across the State into future multiple markets globally.

* Leases signed by the producers on the North Slope legally stipulate there is an implied covenant to market gas produced within a "reasonable time" and at a "reasonable price". It is assumed that 34 years since the start of production at Prudhoe Bay meets the "reasonable time" stipulation. Producers will thus have to sell their gas to pipeline companies or third parties if "reasonable price" offers or bids are received for their gas and assuming other bid terms are acceptable.

Goal #2: Assess how natural gas or natural gas products can meet the clean and economical energy needs of communities along the pipeline route and in rural Alaska.

Recommendation:
The State should sponsor a comprehensive economic and environmental study of assessing fuel switching in certain Interior and rural communities from diesel to cleaner burning propane to provide information for the likelihood of economic natural gas "hub" propane processing facilities.

Recommendation:
The State should sponsor a comprehensive economic and environmental study of assessing broader electrical power distribution to certain Interior and rural communities to provide information for the likelihood of economic power generation plants near natural gas "hub" offtake points.

Recommendation:
The State should encourage private investors to initiate an economic study of creating one or more "gas hubs" for gas distribution, natural gas liquid processing, and/or power generation near Fairbanks, with a spur line to Anchorage and other "hub" locations that could distribute to Valdez and Southeast Alaska cities. This would foster a broader clean energy natural gas, propane and electrical distribution system within Alaska once a pipeline is endorsed across Alaska.

Conclusions:
* Because a North Slope gas pipeline will likely be heavy-walled and high-pressure, and will likely transport large quantities of natural gas liquids, any "tap" on the pipeline for local access to gas will be very expensive and may require facilities to remove the natural gas liquids. It is possible that only one or two "hubs" for gas offtake, for local natural gas use or gas-based industrial development, may be economically viable.

* To other communities without large populations, affordable and clean energy from the gas pipeline might best be distributed from gas-fired power generation at the offtake hubs, or through bulk distribution of propane more widely across Interior communities and rural Alaska. Large quantities of propane, a well-known natural gas liquid fuel source, will be moved through the pipeline and can be removed at "hub" natural gas processing facilities.

* In an economic analysis of fuel-switching in Interior Alaska, the local cost of replacement or conversion of oil-burning stoves and generation equipment must be included, and the positive economics on the environment of cleaner burning natural gas, propane or electricity must be assessed.

Goal #3: Assess the costs or benefits of the state taking its royalty share "in-kind" for facilitation of in-state access and use.

Recommendation:
The State should retain its right to take its royalty share of gas on the North Slope "in-kind" or "in-value." This flexibility creates competition to maximize wellhead value for the State by either the producers or other firms such as energy trading companies interested in marketing the State's share of gas. The producers have requested a long-term commitment by the State and are asking the State to decide up front to take either "in-kind" or "in-value." The Council feels the flexibility to switch on six

months notice is very important, creates marketing competition and ultimately maximizing resource value. The State should not negotiate away its right to take its royalty share of gas "in-value" or "in-kind."

Recommendation:
The State could maximize the value of its natural gas royalty resource with a mixed portfolio of "in-value" and "in-kind" sales, with in-kind royalty marketed by energy trading companies such as Duke Energy, Enron, Williams Energy or major companies like them. The State should put its royalty "in-kind" gas out for bid and seek bids from multiple parties for contract terms and price. Such contracts should ask for a "floor price" equal to or exceeding the average netback wellhead price achieved by the three major producers, or from "in-value" sales as "insurance" that the energy trading companies are working in their marketing to beat the producers gas sales realization.

Recommendation:
When there are out-of-state sales using an energy trading company, the energy trading company will reserve the capacity and the liability associated with that capacity, and that liability will not fall back on the State.

Recommendation:
The State may choose to direct market some portion of its gas to in-state consumers using State staff, but it is recommended that sales to customers in outside markets be handled by professional energy trading firms, considering the complexity of and rapid change in those markets. This would also allow those firms to absorb the risk of nominating pipeline capacity and buying hedging instruments to lessen risk on pricing of contracts.

Recommendation:
By keeping some portion of its royalty share of natural gas "in-kind," the State may be able to make some contract deals with consumers in-state at more favorable terms than the producers, as the State might realize added dollar benefits through jobs and corporate taxation of value-added processing such as natural gas liquids processing, petrochemical manufacturing, power generation, etc. that may not otherwise be economically viable to entrepreneurs within the state. However, there should not be a subsidy in sales of royalty-in-kind gas. The State should receive a netback price for royalty gas equal to or greater than the market-based "netback value" of gas on the North Slope.

Recommendation:
To the extent practical, the State of Alaska should enforce its "higher of" clauses on natural gas royalty, as this could add value and ensure producers work hard in their marketing to obtain the best value in their sales of natural gas. When the State elects to take any share of its royalty gas "in-value," existing lease terms and statutes allow the State to receive royalty payments and production taxes on the "higher of" actual proceeds or market value. Other states, as well as the U.S. Minerals Management Service, are aggressive in ensuring all producers pay this "higher of" price for royalty and relevant taxes and receive such payments from the same producers that produce on the North Slope.

Recommendation:
Because of the complexities of the natural gas industry and the differences with the oil industry, the State should form a Natural Gas Services Group with people experienced in the natural gas industry,

shipping, marketing and trading so that the State becomes even more sophisticated in understanding deals and transactions that are often involved in the natural gas business. The group would provide an oversight function on sales of royalty gas out-of-state, but could also negotiate and manage in-state sales much like the Division of Oil and Gas now manages sales of royalty oil.

Recommendation:
For more cost effective development of in-state gas infrastructure resulting in more economical transportation of state royalty gas within the state, the State should encourage entities to examine the port authority concept of tax advantaged financing for a gas "hub," spur lines and other distribution facilities.

Conclusions:
* Current North Slope oil and gas leases, and State statutes, allow State royalty production share to be taken "in-kind," i.e. physically take the oil or gas and market the products itself or arrange for other parties to purchase the gas at market value contracts; or to take "in-value," i.e. allow the producers to sell the products and pay the State their realized value of wellhead price after deduction of certain transportation costs. The State has the option to switch between taking its royalty share "in-kind" and "in-value" every six months. Current state law requires any "in-kind" sales, however, to obtain values equal to or higher than "in-value" sales.

* The current North Slope producers have complied with the "in-kind" or "in-value" lease terms and statutes in other states and on federal offshore leases for decades and have instituted internal procedures that allow them to process the selection of "in-kind" or "in-value" promptly. Other states and the federal government also have internal processes for administering the switch between "in-kind" or "in-value" as does the State of Alaska for its royalty share of oil. The producers' arguments that Alaska must decide up front on "in-kind" or "in-value" to ease marketing and sales administration or to bring more certainty to gas transportation or marketing are not valid considering the same producers' decades of experience successfully administering such programs for transportation and marketing elsewhere.

* The natural gas industry in the U.S. is very sophisticated in gas trading and marketing. There are energy trading companies which may be able to market the State's royalty gas for a higher netback price than would be paid by the producers if the gas were taken in-value. If so, the State's leases include a "higher of" clause which means producers would have to pay royalties and taxes on the higher of their actual netback wellhead price or the actual netback wellhead price of an energy trader. This, in a way, creates competition and options to achieve the best possible wellhead netback value.

* In testimony from the General Land Office of Texas, the committee learned that Texas has similar "higher of" clauses in their state leases that they enforce. In 2000, enforcement of the "higher of" clauses, with producers paying royalties and taxes on the highest actual netback wellhead price achieved on various leases, resulted in additional revenues of $17 million. Alaska's royalty gas sales will be ten times higher than Texas' volume of royalty gas sales.

* Alaska may achieve higher prices on some of its royalty gas by allowing energy trading companies to market the State's "in-kind" share. The State of Texas takes 53 percent of its royalty gas in-kind and 47 percent in-value, and claims to achieve higher prices on much of its royalty-in-kind sales by achieving better negotiated pipeline tariffs, higher customer prices or integration for power generation.

* However, the flexibility in taking royalty-in-kind is important for other reasons as well as price. First, royalty sales will allow the State to periodically test the market, to assess whether it is getting fair market prices from producers. Second, allowing energy trading companies to market royalty gas will create more competition by accessing different customers than the producers and broadening the market exposure of Alaska's natural gas.

* While Texas is able to market its royalty gas with a small staff of state employees, Alaska should "outsource" its sales of royalty gas to the lower 48 or other outside markets to an experienced gas trading firm. Because large volumes of Alaska royalty gas may be marketed in several of the lower 48 gas markets or outside markets initially, a thorough understanding of and experience in those markets will be required.

* On the other hand, it may be more appropriate that the State negotiate directly for sales within Alaska of in-kind royalty gas as is now done with royalty oil, because of the better understanding of local conditions. A section within a new Natural Gas Services Group could perform this function.

* The concept of a public authority owning a segment of a natural gas pipeline within Alaska may present significant benefits for transportation of State royalty gas to in-state users. The tax advantage of a public authority, for example, would allow a lower tariff for transporting gas within the state, and resulting savings could help generate more business activity by providing natural gas at lower prices to consumers. The netback price, however, should remain at market values.

Goal #4: Determine the "best practices" for methodologies to achieve transparency in netback pricing valuation at the wellhead and transportation to assure fair and favorable pricing for in-state gas business creation and expansion as well as for taxation and royalty calculations.

Recommendation:
The State should keep a natural gas price netback valuation methodology based on actual sales proceeds, or sales contracts, and not change to a formula linked to average prices in gas trading hubs or some other general formula at least for the first several years of major gas sales. The State's right under lease terms and statutes to obtain actual realized prices for its gas and natural gas liquids should not be negotiated away.

Recommendation:
With the growing natural gas liquids (NGLs) business in the U.S., the State should keep a natural gas liquids price netback of gasline liquids based on actual sales proceeds, or sale contracts, of the liquids and not accept a value for the liquids based on a BTU adjusted basis of the gas stream unless there is clearly a higher value obtained by BTU-based sale. The State should be very sophisticated in its assessment and knowledge of the business of NGLs, as revenues from NGL sales will be a substantial part of revenues from the overall gas stream.

Recommendation:
Alaska statutes should be reviewed and updated to require information on sales spot transactions, sales contracts, actual transportation costs and other information be made known to the State, much as statutes in Texas and other locations provide for. When updating these statutes the process should

be clarified in a way that assesses the "lessons learned" on the Alaska oil valuation disputes and provides for more timely resolution of any differences in valuation.

Recommendation:
Alaska statutes should be reviewed and updated to require information on "affiliated sales" by producers be made known to the State, much as statutes in Texas and other locations provide for.

Conclusions:
* Several years of North Slope oil production disputes on netback pricing valuation resulted in major hearings and extended litigation. The State was able to resolve these issues after several years of production once access to oil sales contracts, invoices and transportation charges allowed the State and the producers to agree on a formula for purposes of calculating royalty. The experience with production made both the State and producers confident that the formula tracked market values, or actual proceeds of oil sales. This history may or may not be of value in regard to gas price valuation. Certainly it is in both the State's and the producers' interest to avoid replication of the lengthy disputes on royalty and severance taxes experienced with the first decade of North Slope oil production.

* In contrast to oil, there have been no sales of North Slope gas, nor are gas sales contracts in place or other similar information available. For the first several years of natural gas production, the State should certainly rely on existing measures of royalty value in the lease, which include value based on sales proceeds. The State should, however, review the oil valuation disputes and see if additional clarification of information, data, definitions, etc. is required to achieve a better mutual understanding by the producers and the State to lessen points of future disagreement. An agreement on an alternative formula for royalty valuation on gas may never be needed to maximize value to the State. In the future there could be sufficient production experience to allow agreement on a formula for valuation if needed. Billions of cubic feet of natural gas are sold from various states and federal leases under the actual netback pricing mechanism. While there have been disputes, there have rarely been pricing formula agreements adopted in lieu of an actual netback pricing approach.

* Natural gas hub spot prices could be too easily affected, at certain times and at certain locations, by market forces external to Alaska. This concern of hub posted prices for oil was evidenced by the Federal Trade Commission (FTC) forcing a sale of oil trading hub facilities in the Cushing area because of the concentration of ownership of facilities at that trading hub location by BP, Amoco and ARCO upon their mergers. While the FTC did not claim unfair trading affecting oil hub posted prices would or was taking place, the FTC did feel too much concentration of power at such trading hubs could affect posted prices. It may be possible that concentration of interests and gas trading spot volumes at certain gas trading hubs periodically in the future could potentially skew hub prices similar to the FTC concern. Alaska should simply use the maximum, actual realized price as fair market value.

* Information on sales spot transactions, sales contracts, actual transportation costs and other related information will ensure that reliable data is provided so the State can accurately calculate the actual realized wellhead netback gas price. Such information is provided by the North Slope producers on other states' leases where required and on many federal leases. Companies have internal record keeping and software systems in place to provide in a timely manner such information for accurate calculation of netback gas prices.

* Having information on "affiliated sales" will ensure the State has knowledge when a producer sells natural gas to an affiliated subsidiary company for additional value added marketing, processing or manufacturing. Having such knowledge of affiliated sales can help the State screen that a fair market value is being obtained for the gas, versus a value being obtained that is less than market while the affiliate captures additional value downstream.

* Testimony to the subcommittee showed that Texas bases its royalties on actual proceeds and requires producers to report to the State, on a monthly basis, information on sales contracts, points of sale and transportation costs. Texas General Land Office staff has developed computer software to track these transactions and to ensure the accurate calculation of lease netback for purposes of producers, in turn, calculating accurate royalty and tax payments. The companies that report these transactions in Texas include all three of the major gas producers on the North Slope. Texas has offered to make its computer models used in monitoring transactions available to Alaska.

Goal #5: Recommend policies that assure clear and transparent rules for access to natural gas into and out of the gas pipeline for Alaska businesses and customers.

Recommendation:
The State must develop a clear and sophisticated understanding of the "open season" rules governing access to a contract carrier pipeline and devise strategies to facilitate access to the pipeline for firms exploring for or developing new gas discoveries on the North Slope or Interior basins.

Recommendation:
The State should incorporate in any federal legislation the right to gas access in-state. This right is provided in ANGTA but is not provided in the producers' recently proposed federal legislation.

Recommendation:
The State should first seek federal legislation that gives the Regulatory Commission of Alaska (RCA) authority to set tariffs for the transportation of intra-state gas used in-state similar to that authority given to the RCA for tariff review on the TAPS oil line. The state RCA should review applications for pipeline access within the state to ensure fairness in pre-determined fees and terms based on reasonable rates of return for investors who ship to in-state consumers.

Recommendation:
Failing to achieve RCA obtaining sole authority in-state, the State should seek through federal legislation the creation of a joint board between the Regulatory Commission of Alaska and the Federal Energy Regulatory Commission (FERC) that would have authority to set tariffs for the transportation of intra-state gas used in-state. This joint board should participate in review of applications for pipeline access within the state to ensure fairness in pre-determined fees and terms based on reasonable rates of return for investors who ship to in-state consumers.

Recommendation:
Alaska should consider including a "fairness" clause in the granting of State right-of-way approvals across state lands to guarantee fair access, similar to provisions developed by Texas for pipeline rights-

of-way approved across state lands. Such a clause will give the State valuable leverage in negotiating fair access rules. The clause could also provide an avenue for appeal to the RCA in the event of disputes.

Recommendation:
The State should complete a thorough socio-economic study of various approaches to in-state natural gas pricing of in-kind royalty gas.

One approach is that the sales price of in-kind royalty gas or gas liquids to in-state users, whether private or State, be based on the market netback price of gas on the North Slope (which is determined by subtracting actual pipeline transportation costs from actual realized market sales prices in the lower 48 or other outside markets) adjusted for intra-state tariffs actually incurred for the transportation of the gas to the in-state access point, or hub, and then transportation costs to the consumer with allowance for a reasonable rate of return on investment. Price of gas or gas liquids to in-state users should not be based on comparisons with alternative fuels, such as diesel. Providing that the intra-state tariff is determined on a prorated basis and not the "postage stamp" methodology, this policy will create a supply of reasonably priced, clean energy for communities in Interior Alaska, and ultimately Southcentral Alaska if a spur line is built. These more affordable natural gas prices would be passed along to consumers who purchase from a regulated utility but may not be passed along to consumers who purchase from a non-regulated company. A problem with this approach is that the State receives a potentially lo ver netback value than if the price is determined through competition with other fuels. This may favor the consumers in that area at the cost of lower State revenues. On the other hand, such an approach could mean more affordable natural gas to a large number of customers who purchase from regulated utilities, potentially enhancing economic development and quality of life for businesses and consumers.

Another approach is that the sales price of in-kind royalty gas or gas liquids to in-state users should be based on being competitive with the pricing of alternative fuels, as that may create higher netback prices resulting in higher royalty and tax revenues to the State. This would potentially increase the revenue received by the State but would not significantly lower the costs of consumers using this in-kind gas or gas liquids. However sellers other than the State could compete for these higher netback markets and so drive the price down well below the alternative fuels.

Conclusions:
* Some existing, large pipeline companies in the lower 48 have built pipelines with spare capacity as a speculative investment, allowing for future growth in volumes and revenues. Some pipeline companies do not invest in speculative capacity. Producers also tend not to invest in speculative, spare capacity but tend to construct to immediate capacity needs.

* Without spare capacity in the pipeline, it is very important that the State have a clear understanding of the "open season" rules and how to position for new entrants being allowed to produce into the pipeline.

* It is recognized that with a thick-wall, high-pressure pipeline, access taps and liquids processing facilities will be expensive. Points for gas offtake might be limited economically and operationally to only one or two distributions "hubs" along the pipeline route in Alaska.

* With a limited number of "hubs" for offtake, it may be more economical for several Interior and rural communities to obtain the clean energy not by direct natural gas use, but by benefiting from potentially economic electricity generation and natural gas liquids (propane) distribution from the centralized "hub" location(s).

* To fairly govern gas taken off at an in-state distribution hub(s), general access terms should be developed in advance by the RCA (or the joint board of RCA and FERC) that are clear and understandable. Similar general terms have been developed to govern contracts at gas trading hubs in the U.S., United Kingdom and the European Union.

Goal #6: Assess pipeline sizing and the pipeline "contracted volumes" structure for growth of in-state use and/or potential future export markets to Asia and the West Coast, or expansion of deliveries to the lower 48.

Recommendation:
The State should investigate ways of working with pipeline transmission companies as investors to build in excess capacity, to provide space for transporting new gas that will be discovered on the North Slope or Interior basins.

Recommendation:
The State should evaluate innovations in using part of its "in-kind" royalty share in contract sales to energy trading companies who can bid for shipping capacity which then may be used in a creative way in the future to ship gas from new discoveries while the State elects at the time of new discoveries to change and sell the originally nominated royalty gas volumes "in-value."

Recommendation:
The State should seek an order by FERC, or federal legislation, for periodic open-season nomination periods, to allow for additional capacity to be built for new gas, when triggered by requests from existing or potential producers, transporters, shippers, customers or the State.

Conclusions:
* Failure to provide for additional capacity either at startup or through future open seasons could have the effect of creating a "monopoly" on pipeline capacity by existing producers, discouraging exploration by others who are not owners of the pipeline.

* Strategies for natural gas pipeline open season nominations and shipping arrangements become very complex. A new Natural Gas Services Group could have such expertise in-house or these skills could be out-sourced to experienced gas trading firms.

* Because of current lease terms and statutes, the producers must allow enough capacity and construction size to ship the entire volume of the State's royalty share of gas "in-value" if the State were to elect at any time to have its royalty share sold direct by the producers.

Goal #7: Evaluate conceptual options for future value-added projects during the 50-year life of gas reserves for in-state use and/or export to Asia and the U.S. West Coast.

Recommendation:
No one can rule out with certainty the viability of value-added processing of natural gas in Alaska over the next 50 years. Alaska should have a natural gas pipeline that allows this option to remain open. The previous recommendations regarding access, reasonable tariff and pricing, and capacity expansion will keep these options open.

Recommendation:
Gas and gas product markets are highly cyclical in price and somewhat cyclical in demand, and somewhat regional in nature; thus the State should facilitate a pipeline option that will allow access to multiple markets in the future.

Recommendation:
As markets change, the State should take a proactive role in encouraging investors to consider the possibilities for liquefied natural gas (LNG), gas-to-liquids (GTLs), expanded uses of natural gas liquids (NGLs such as propane, butane) and downstream processing such as petrochemicals.

Conclusions-General:
* Original investors in the Trans-Alaska Pipeline System, the producers, estimated the life of the North Slope oil fields at 25 to 30 years. Twenty-five years have passed since startup of the TAPS line, and these investors are now applying for a 30-year extension to the rights-of-way for TAPS, so that oil developed since the pipeline startup can be shipped to market.

* The same circumstance may develop for North Slope gas, as exploration continues on the North Slope. Accordingly, the State should position itself for a 50-year life for a new natural gas industry and encourage development of a system that will access multiple markets. Only a gas pipeline following the southern route will be able to access additional markets through a spur line to an LNG plant on the southern Alaska coast.

* Oil and gas are commodities, and all commodity markets experience supply/demand and price cycles. If Alaska has access to multiple markets for gas, to the lower 48 through an all-land pipeline, to the U.S. West Coast and Asia through LNG shipments, and into the growing petrochemicals industry through sales of gas and natural gas liquids, the State will benefit because the commodity cycles may be different in these markets at different times as has been past history. In the future, there could be a more uniformly priced global gas market; however, there will likely remain cycles in volume demand or demand trends by regions.

* There is also the longer-term potential for a gas-to-liquids industry, with plants in Alaska manufacturing clean-burning liquid fuels directly from natural gas, and for development of new industries related to the petrochemical industry. These may be important future "value-added" industries for the state over the long-term.

Conclusions-LNG:
* Both Cambridge Energy Research Associates and the gas producers have provided information to the committee that the cost of delivering LNG to Asian markets is currently not competitive with

LNG supply from other sources, such as Indonesia, Malaysia, Australia and the Middle East.

* Yukon Pacific Corp., the Alaska Gasline Port Authority and a citizens' group have presented information that they believe LNG export from Alaska is currently competitive. Yet none of these organizations have secured substantial financial backing or presented firm contracts for sales of LNG.

* Despite this, no one has presented information that rules out LNG in the future. Asian nations may want to secure large-scale supplies of LNG from Alaska for purposes of energy security, so as not to be dependent on one or two regions such as the high-risk Middle East for the majority of import needs. Therefore, it is in Alaska's interest to maintain the flexibility to be able to supply LNG to export markets, or to U.S. West Coast markets, in the future.

Conclusions-GTL:

* Large-scale gas-to-liquids projects, the making of clean-burning liquid fuels from natural gas, could be an option for North Slope producers if they do not proceed with a gas pipeline project. These liquids could be shipped down the existing trans-Alaska oil pipeline. Testimony from the producers and information presented at a recent international conference on gas-to-liquids, held in Girdwood, indicate that large-scale application and commerciality of such a remote resource of gas as the North Slope reserves using GTL technologies may be a few years in the future, if ever, versus competitive sources of gas elsewhere that could use the GTL technologies.

* There is sufficient potential for growth of North Slope gas reserves, and the expectation is that there will be sufficient reserves established for both a conventional gas pipeline and gas-to-liquids plants, once it can be shown that Alaska GTL plants can be commercially viable on a large scale.

* A possible negative for a stand-alone GTL project, without a gas pipeline, is that it would lock Alaska into one market for its gas: the West Coast fuels markets. It may not be cost competitive to serve other markets with GTL fuels from Alaska because of shipping distances. However, if a gas pipeline is built, GTL could be a potential value-added product that reaches a different market: the future demand for clean-burning fuels on the U.S. West Coast.

Conclusions-NGLs:

* Information presented at the Girdwood GTL gas conversion conference indicates major breakthroughs in cost-reductions of processing natural gas liquids through related technologies. Costs of processing NGLs today is seen as much less than was the case a few years ago. This could serve to enhance the viability of a gas pipeline that also carries NGLs to market.

* The NGL business in the U.S., mainly in propane and butane, is a very large multi-billion dollar industry and a key component of the integrated natural gas industry. The producers are studying the construction of a large NGL extraction plant in Alberta.

* A gas access and distribution hub(s) built near Fairbanks or Delta Junction could facilitate expanded production and sale of NGL products in the state, for distribution to Interior or rural communities. Fuels from NGLs have the potential for becoming an economic and clean-burning alternative source of energy for Alaska communities. The Williams Companies and other firms in Fairbanks are now assessing investment opportunities and potential for uses of NGLs.

Conclusions-Petrochemicals:

*A previous assessment of a petrochemical industry for Alaska, done by Dow-Shell, found that a petrochemical industry would not be viable in Alaska at the time that study was done. However, changed circumstances have affected several assumptions used in the study. Dow-Shell assumed that a separate, small-diameter gas liquids pipeline would be built from the North Slope and envisioned an industry based on manufacturing complex petrochemicals.

* Today there is a proposal for a natural gas pipeline that could also carry NGLs, so there is no need for a separate pipeline. Also, one new study underway of using NGLs, by Williams, envisions manufacturing a simpler petrochemical product than that envisioned in the Dow-Shell study.

* Williams' study is considering the making of polypropylene, one of several petrochemical products in the olefin family, and shipping the product via the Alaska Railroad to Anchorage for shipment to markets in Asia. Olefins are fundamental feedstocks for the rapidly growing plastics industry. It is a business involving $41 billion in annual sales, with significant supply shortfalls expected in 2006. Williams has completed an initial screening study and is now engaged in a more detailed analysis of its study.

* All three major producers on the North Slope have recently expanded their olefins business in the lower 48. All three of the major producers have extensive separate businesses in olefins in the U.S. and Canada. For example, ExxonMobil is ranked as the number 3 producer of ethylene in North America, while Phillips-Chevron is number 4 and BP is ranked number 7.

Goal #8: Determine strategies to promote and attract investment for in-state distribution and value-added processing.

Recommendation:

The state should develop and periodically update a formal marketing plan to attract investors in Alaska who may be interested in in-state gas distribution or development of value-added industries. Assisting this could be an additional function of a new Natural Gas Services Group within the Department of Natural Resources.

Conclusions:

* It should be recognized that Alaska businesses, such as Enstar and Fairbanks Natural Gas Company, have already voiced interest in developing more in-state distribution.

* While the scale of in-state processing may not be attractive to the major producers, in-state value-added businesses may be of interest to Alaska Native Corporations and other Alaska companies once a gas infrastructure exists.

Alaska Highway Natural Gas Policy Council

Committee Report
Environmental Considerations Committee
Peg Tileston, Chair

Goals:

- To define and address key environmental issues, both natural and human, associated with the construction of a natural gas pipeline.
- To make recommendations for policies and procedures necessary to ensure that the design, construction and operation of the natural gas pipeline will proceed in an environmentally sound manner.
- To identify potential environmental benefits of a natural gas pipeline.

Introduction and Background

The proposed Alaska natural gas pipeline project is comparable to the Trans-Alaska Pipeline System (TAPS), which was built in the mid-70s to transport crude oil from Prudhoe Bay to the Valdez Marine Terminal. The gas pipeline under consideration is proposed to be large-diameter (up to 52 inches), high-pressure, chilled, completely buried (except for above ground crossings of the Yukon River and possibly the Tanana River), and supported by a number of compressor stations. In addition, a large conditioning plant will be required on the North Slope to treat the natural gas before it enters the pipeline. Furthermore, the proposed Highway route would be international, crossing portions of the United States and Canada and thus requiring trans-boundary coordination of the pipeline's daily operation, maintenance and emergency response capabilities. Except where noted the comments in this report deal solely with the Alaska segment of the proposed gasline.

Much has been learned from the TAPS experience over the last 27 years. When the State of Alaska and federal agencies undertook oversight of the design and construction of the TAPS project, there was limited understanding of the impacts and problems associated with a project of that magnitude. Delays caused by litigation provided industry and agencies with an opportunity to review and improve TAPS engineering design and construction planning. This review resulted in successes, but there were also unanticipated failures. Careful planning and design, as well as continued vigilance in monitoring and enforcement are essential to reducing environmental concerns.

Oversight and regulation of TAPS has been enhanced over time due to a commitment to continuous improvement of the oversight process by industry, government and the public. In the early 1990s, the Joint Pipeline Office (JPO) was established to provide a coordinated, cooperative federal-state structure for oversight of the line. This has proven to be an effective inter-agency oversight mechanism. A similar joint office, the Gas Pipeline Office (GPO), has been established for the natural gas pipeline, and it is important that it be adequately funded and staffed with highly qualified personnel to provide the needed agency liaison and coordination of the permitting standards and process.

The impacts of a project of this magnitude will be extensive, particularly during the construction phase, and must be considered not only in the context of the natural environment but also as it will

affect the human environment. Quality of life in communities can be degraded in numerous ways ranging from reduced services, traffic congestion, crowded schools and health services, reduced recreational opportunities and inflationary pressures. Rural residents depending on subsistence may experience increased industrial and recreational activities in traditional hunting and fishing areas. On the other hand, pipeline construction will create jobs and increase short-term economic opportunities, and the completed pipeline could supply natural gas to communities that presently depend on less efficient liquid petroleum products for energy, altering lifestyle and environmental patterns ranging from fuel consumption to air quality over the long term.

The charge for the Environmental Considerations Committee of the Natural Gas Policy Council is to make recommendations to assure that the project follows Governor Knowles' policy of "doing it right." The committee has determined that its most effective contribution is to recommend needed policies and procedures, many of which should be put into place as early as possible during engineering design and prior to the start of construction. Every effort must be made to ensure that best technology and best environmental practices are implemented in order to make the project as environmentally benign as possible, and to make sure that the net impact on human lives will be positive. The following recommendations to decision-makers are presented with these goals in mind.

Recommendations and Supporting Rationales

1. Endorse the Alaska Highway route as the environmentally preferred pipeline route that minimizes the potential adverse environmental effects and maximizes potential environmental benefits to Alaska.

> An Alaska Highway route would limit the gasline to an existing corridor, minimizing impacts to the environment as well as to fish and wildlife. It would also allow Alaska communities access to a cleaner, more efficient fuel. In addition, a highway route following the TAPS line would make oversight of both lines more efficient and effective. At hearings of the Gas Policy Council, Alaskans voiced overwhelming support for the environmentally preferred southern route.
>
> A rigorous environmental review should be required. There are three approaches to this. The most expeditious approach but the one most susceptible to challenge is to meet the requirements of Section 5, subsection III of the President's Decision relating to the Alaska Natural Gas Transportation System (ANGTS) which anticipated the development and public review of detailed plans to protect the environment using the best of current science and technology. The two other approaches are either a supplemental environmental impact statement (EIS) building on the ANGTS EIS or a full EIS done in an expedited manner using information from the ANGTS EIS. The outcome of any process should spell out for public review the alternatives associated with the Highway route, the environmental pros and cons associated with them and mitigation measures that should be taken to avoid or minimize adverse impacts.
>
> Any frontier route would require a "start from scratch" approach, including collection and analysis of physical, biological and social data, and determination of required technology.

2. Adequately fund and staff a natural gas pipeline office that is housed in one place to facilitate communication, coordination and cooperation among all affected state, federal and Canadian agencies.

Lack of timely and complete communication among agencies can have severe consequences on any project, but can be particularly difficult in one of this size. A facilitated review of the JPO operation by all the involved agencies to note procedural changes they might recommend to improve effectiveness and efficiency would be beneficial. Acquiring personnel with the necessary technical and scientific expertise may be difficult for both federal and state agencies when competing with industry, which will be hiring for the same positions and will have considerably higher salary scales. Every effort should also be made to include the considerable number of borough and local agencies concerned with the various project alternatives, along with Alaska Native corporations, tribes and villages that will be affected by a pipeline right-of-way (ROW).

3. Recommend that the Gas Pipeline Office (GPO) conduct a thorough review of "lessons learned" from TAPS design, construction and operation. This review should include public comment and public participation. Use "lessons learned" to develop procedures for the gas pipeline that ensure past mistakes are avoided and successes repeated.

A natural gas pipeline following the TAPS/Alaska Highway corridor will have many environmental concerns similar to those of the earlier project. Certain differences need to be identified and addressed, such as the effect of a buried, chilled pipeline crossing beneath streams, geologic and hydrologic data for areas where TAPS is not buried, and design and operational differences between a low-pressure, hot oil line and a high-pressure, cold gas line. In addition, Canadian and other high-latitude gas pipelines should be studied for lessons learned.

4. Establish an open and available data and information process for the public, agencies and industry.

Frustration and suspicion take hold when individuals, organizations and communities are unable to get information on issues of concern in a timely and appropriate manner. Such a process should start at the beginning of the project and make available all non-proprietary material. Meaningful involvement by affected communities is important. Effort should be made to include all stakeholders, not just decision-makers. Websites, e-mail addresses and information repositories, such as local libraries and borough offices, should be used to disseminate information. A central site, preferably the Alaska Resource Library & Information Services (ARLIS), should be used as effectively as possible and adequately funded. An information clearinghouse such as the Exxon Valdez Oil Spill Library (which is now consolidated in ARLIS) could be an appropriate approach.

5. Establish mandatory training for all personnel involved with the gas pipeline project.

Timely, appropriate and sufficient training is vital for all personnel associated with a major project. Such training should start with applicable federal, state and local laws and regulations, agency mandates and responsibilities, enforcement options and penalties for noncompliance, best practices, and appropriate technologies. Government and industry should coordinate to ensure commensurate levels of training for the public and private sectors, including all contractors and subcontractors. Sessions to update personnel as the project progresses should be included, along with required orientation for those joining it.

6. The State should take a long-term view of the gas pipeline to minimize environmental concerns.

In view of the likely long-life of this project, the State should encourage a long-term view be taken in design, construction, operation and maintenance in order to mitigate environmental risks over the entire life of the project.

7. A records management system for compiling and maintaining complete and updated documentation should be in place at the beginning of the project and maintained and updated throughout the life of the pipeline in accordance with professional document control standards. The State must have copies of all documents.

The TAPS experience has shown that older engineering drawings, including "as-builts" and documents confirming original facility configurations and placements, have not always been readily accessible by pipeline managers and regulators when needed. Establishing a professionally designed and maintained document control system will help to ensure that accurate records from every phase of pipeline development remain rapidly retrievable under unforeseen future circumstances. Recent advances in technology will undoubtedly aid this process.

8. Assure that effective and adequate monitoring and enforcement systems are in place at the start of the project and continue throughout the life of the pipeline.

Adequate funding will be needed to ensure that a sufficient number of appropriately trained agency personnel are available for monitoring and enforcement throughout pipeline construction and operation. Agency personnel without a working knowledge of pipeline construction, operation and maintenance will have little credibility with their industry counterparts. Training of agency personnel associated with all aspects of the pipeline should be integral to the project. Such training should emphasize the prevention and early detection of problems, and understanding of regulations, codes and penalties. Enforcement of regulations and codes is essential but will not occur without trained personnel who are actually available on site.

9. Direct the GPO to establish a comprehensive citizen's involvement plan. This effort may include the creation of a citizen advisory council with representatives from communities affected by construction of the pipeline.

A determined effort should be made to aggressively involve and engage affected communities during the planning and construction phase through a coordinated federal/state effort. If necessary as determined by the federal/state plan, a citizen advisory council should be formed and adequately funded to receive and evaluate information and respond to pertinent issues. If established, the council would also evaluate their role following construction of the pipeline.

The public involvement process should also include a full review, including stakeholder involvement, of proposed federal grant and state lease right-of-way provisions and stipulations.

10. Provisions should be incorporated into ROW lease agreements to ensure that adequate dismantling, removal and restoration (DR&R) funding will be available for the Alaska segment of the natural gas pipeline.

> The actual DR&R provisions will depend on ownership of the pipeline and should take into consideration the long life of the asset.

11. Perform a full security review and develop a comprehensive and detailed security plan early enough to influence the pipeline design and alignment process.

> Heightened security concerns throughout the United States should be reflected in the engineering design and alignment of the natural gas pipeline, which will be a significant part of America's domestic energy supply. Any aspect of the design of pipeline facilities and structures that would be particularly vulnerable to sabotage, such as compressor stations, bridge crossings and above-ground valve housings, should receive attention from a security standpoint early in the design process, and not as an afterthought. This concern applies also to the alignment, which may present opportunities for modifications or adjustments that will minimize the potential for harm.

12. Continue to ensure that environmental scientists and permitting specialists work side-by-side with design engineers and construction planners from the earliest stages of the project through to its completion.

> It is essential that environmental safeguards be built into the design of the project, not added as an afterthought to satisfy regulatory requirements and stipulations. Preliminary engineering design products will be used to support major permit applications with long lead times and must contain fully integrated environmental features at that early stage. This can best be accomplished if environmental and permitting specialists work on the same teams and in the same facilities as the engineers.

13. The State of Alaska ROW lease should require long-term environmental surveillance and monitoring, and annual reporting. This function should continue throughout the life of the pipeline.

14. The GPO, in cooperation with the federal government, should continue to coordinate the trans-boundary aspects of construction, operation and maintenance of a gasline, including operations control and emergency response.

> Although it may cross land belonging to two nations, the gas pipeline will be a single integrated system. Emergencies, whether structural, operational or environmental, will not respect the international boundary. The U.S. and Canada must establish integrated control protocols that can regulate the pressure and flow of gas through the pipeline as a single system and thus respond quickly and effectively to emergencies. This will require open communications, shared data and a close working relationship between personnel of both nations. The State should look to other international pipelines, particularly between Canada and the United States, for models in handling the trans-border oversight aspects of construction, operation and maintenance.

Section III:

Meetings and Public Hearings

Alaska Highway Natural Gas Policy Council

AGENDA

Thursday, March 1, 2001, 10:30 a.m. to 2:00 p.m.
Anchorage Sheraton Hotel

I. Welcoming remarks from Co-Chairs Jim Sampson/Frank Brown

II. Opening remarks from Governor Tony Knowles

III. Opening remarks from Lt. Governor Fran Ulmer

IV. Presentation from Department of Natural Resources Commissioner Pat Pourchot

V. Presentation from Cambridge Energy Research Associates

VI. Ten-minute break

VII. Working lunch and Council member self-introductions

VIII. Establish organizational structure

IX. Establish timeline and public hearing schedule

X. Closing remarks from Council Co-Chairs Jim Sampson/Frank Brown

Alaska Highway Natural Gas Policy Council

Full Council Meeting Summary
March 1, 2001, Anchorage Sheraton Hotel

Co-chair Jim Sampson opened the meeting, explaining that the Council's structure, organization and schedule of meetings would be discussed in this first meeting. Sampson introduced Frank Brown, his fellow co-chair.

Brown commented that it was his hope, and that of Sampson, to steer the Council through a process to get large amounts of input from individuals and organizations around the state. He congratulated the governor on securing the support of the National Governors Conference for a gas pipeline bringing Alaska gas to lower 48 markets.

Governor Knowles made several opening remarks, expressing thanks to members of the Council for agreeing to serve. "Many of us participated in construction of the first pipeline, the oil pipeline, and rarely do people have an opportunity to participate in a second major pipeline project. We've seen the bumper sticker, 'Please let there be one more boom.' Now there can be a second bumper sticker, 'We did it right this time.'"

Knowles said he created the Gas Policy Council to insure that Alaskans' interests and potential would be promoted and to insure Alaska hire and a fair share of resource revenues to the State. The mission is to promote an Alaska Highway gas pipeline that will also help create a natural gas industry for the state. A project of this magnitude only comes along rarely, and Alaskans have a deep interest in its development. It could open the door to development of the 100 trillion cubic feet of gas potential believed to be present on the North Slope.

The Administrative Order creating the Council identified eight broad topics of inquiry, and the governor realizes more may be added by Nov. 30. Knowles urged Council members to ask tough questions.

Knowles said it is his belief that the best way to develop Alaska's gas is with a pipeline along the Alaska Highway to the lower 48. He added that the consensus of the energy world is that the only market that would ensure an Alaska pipeline is financed is in the U.S. We must act with a sense of urgency to supply that market and to seek national and Canadian consensus in support, the governor said.

There is no question that there has been a long-term structural change in the gas supply and demand situation in the U.S. The urgency is that supply to meet the demand gap will come from other areas if Alaska's gas is not available. "We need to be in at an early stage of development," the governor said.

U.S. and Canadian support is needed. In 1977 an international agreement was signed, which indicates the issue of Arctic gas development is of national importance in both countries. The issue is now beginning to get national attention once again. Knowles noted positions taken in support by the Interstate Oil and Gas Compact Commission, an association of energy-producing states, as well as the Western Governors' Conference and the National Governors Conference.

Because of the earlier work, the Alaska Highway route has already gone through considerable environmental review, the governor said. The fact that the highway route was approved earlier is a tremendous asset. The alternative northern route has had no environmental review, and the State of Alaska has some serious concerns with the effects of large-scale dredging of a pipeline trench in the Beaufort Sea. Even if the northern route is pursued, its approval will be far in the future, Knowles said.

The governor said he has asked Interior Secretary Norton and Energy Secretary Abraham to consider the highway route as an issue of national importance, and they have agreed to consider this. Support from Canada is also needed because 1,800 miles of the pipeline will cross Canadian territory. It is important that the Alaska Highway pipeline be seen in Canada as a way to also help develop Canada's Mackenzie Delta gas. Overall, the project should not be exclusive to other projects. It will help make an LNG export project more viable, Knowles said.

The Council's mission should be to look closely at how the project can create a natural gas industry for the state, the governor said.

Lt. Gov. Fran Ulmer made opening remarks. In meetings around the state she has attended, people are expressing high expectations for the gas project. "People want a piece of this energy." There is potential for low-cost energy and a driver for the Alaska economy, "if it's done right. But there are a lot of ideas out there as to how accomplish this." The important job the governor has assigned to the Council is to listen to people, Ulmer said.

The governor has set standards for resource development, she said. Projects should be based on sound science; prudent management should be assured; and there should be public participation in decisions. "Sound science" requires adequate studies to be done in advance of the project by state agencies, and this will take money. In "prudent management," Canada and its several layers of government will have to be included. "Their resources are affected, too." In Alaska, there will have to be alignment among the several state agencies with statutory authority. The Department of Natural Resources will be the lead agency, insuring coordination among other agencies.

Overall, the gas represents another, bright opportunity for the development of the state's economy, Ulmer said.

Ulmer was followed by State Department of Natural Resources Commissioner Pat Pourchot, who gave a prepared overview of the gas project. *(Note: This standardized presentation was presented at every following public hearing to provide initial information. It is included in Volume II of this report.)*

A presentation by Cambridge Energy Research Associates (CERA) followed, to provide an overview of market trends and opportunities.

(Note: CERA made another presentation to the Council with more updated market assessments later in the summer. The reader may wish to review the more recent CERA presentation made at the Council's public hearing in Anchorage on May 24 and a CERA presentation to the Legislature's Joint Gas Pipeline Committee in late July.)

Despite the very high gas prices of 2000 and early 2001, market conditions may return to more normal levels if there is sufficient replacement of gas in storage through 2001, if there is a cool summer and few hurricanes, along with more supply being made available within the U.S. and from Canada. There could also be lower demand by November and December of 2001, due to the high prices.

This return to more normal conditions for the short term does not change the long-term outlook, however. It is possible that demand may grow to as much as 30 trillion cubic feet (tcf)/year by 2010, from current gas demand of about 23 tcf/year *(Note: later CERA presentations have somewhat altered this assessment.)* However, to support 30 tcf/year demand, an additional 350 tcf of proven reserves must be found. In the 1990s, industry generally replaced production with about 20 billion cubic feet (bcf) per day new production added. This would have to increase to 35 bcf/day to support 30 tcf demand per year. There are other sources of potential new supply. About half a bcf of gas per day is now coming from a new producing area in Canada's Atlantic regions. CERA expects this to increase to 2.5 to 3 bcf/day by 2010. Liquefied natural gas (LNG) is enjoying a reduction in costs, both in LNG gasification in producing regions and LNG regasification in consuming regions. LNG terminals on the U.S. east coast are being brought out of storage status. CERA expects 3 to 3.5 bcf/day of LNG imports into the U.S. east coast by 2010.

As for northern regions, including Alaska and Canada's Mackenzie Delta, CERA expects that up to 3.5 bcf/day could be supplied from these areas by 2019, under several possible scenarios *(Note: see later CERA presentations for more updated assessments.)*

Developers of these northern pipelines face several major risks, the most important that the long-term price must be able to provide a sufficient netback value at the wellhead to not only meet a company's internal minimum hurdle rate for new investment, but also to win the capital allocation battle within a company. Alaska must be seen to be a more attractive investment than new gas developed from the U.S. Gulf of Mexico deepwater regions, the North Sea, offshore areas of West Africa and Brazil, and other new frontier exploration regions. There are also elements of political risk, but these companies are used to working in areas with political risk.

Some of these risks will be shared with end-use customers. Gas producers may share most of the risks to get gas to near the market, but end-users may share risks in gas delivery systems further "downstream." A substantial change in the situation since the last time a major Alaska project was proposed, in the 1970s, is that in these post-regulated gas days the producing companies will now assume the responsibility to get the gas to near the market regions. In the 1970s, when the U.S. natural gas industry was highly regulated, gas pipeline companies were proposing to assume responsibility for building a pipeline and moving the gas to market. In those days, the regulatory structure would have assured a return on the pipeline investment. With the industry now deregulated, this guarantee is no longer available. Producers must now shoulder the burden.

A new development in the gas industry is the collection of changes in LNG business. In recent years there have been several engineering and other technical improvements that have lowered costs of producing LNG. These cost reductions have been driven by major market changes in the LNG trade. In the 1970s, when the world LNG business was first developed, Japan and Korea accounted for 65 to 75 percent of the business. Since LNG import supply was fundamental to the energy security of those countries and the diversification of supply away from OPEC, the facilities were built in a "gold

plated" fashion to insure reliability, somewhat in the same way that nuclear facilities are built to insure safety as well as reliability.

Over the years the LNG business has become more "market-based" primarily because there is so much "distressed" gas in regions where LNG is the only practical development option, to the point that producers have sought to improve technology and lower costs to develop new markets and develop stranded gas.

CERA believes LNG costs have been reduced 35 to 40 percent in the last five to 10 years because of these trends.

Another new factor pushing new LNG supply on the market is that fewer countries are now allowing gas to be flared in regions of oil production (where gas is produced along with crude oil). In these cases, producing companies are being pushed to find commercial uses for the gas, and LNG is one of the few options available.

Because of these changes, CERA believes now that the refurbished U.S. east coast LNG import facilities may be able to bring in new LNG for a price in the range of $2.50 per thousand cubic feet (mcf). Because these facilities were built in the 1970s and 1980s (but then written off when gas prices dropped), they can now be operated at the $2.50/mcf level, with a "hefty margin" for the firms involved.

The nature of the contracts for LNG imported into the U.S. east and west coasts may be different than LNG contracts in the existing Pacific trade (to Japan and Korea). Security and reliability are less important (so the facilities will be less "gold plated") and contracts may be for shorter terms, in contrast to very long-term LNG contracts that exist now in the Pacific business.

Despite potential competition from LNG and other new supply sources, the long-term demand for fossil fuel and natural gas will be large, and the ability of existing producing regions, such as western Canada, to supply these needs is in doubt. The 4 bcf/day of new gas supplied from the Arctic should be easily absorbed.

Following CERA's presentation, there were several questions from the Council.

A question was asked about LNG imports into the U.S. west coast.

The response was that northern Baja California is now being considered as a possible LNG import site. Since northern Baja is already a part of the U.S. grid, electricity and gas can be transported into southern California from an LNG plant in northern Baja.

A question was asked that if gas can be brought into the U.S. via LNG for $2.50 per mcf, does this represent a price "cap"?

CERA responded that the $2.50 estimate was for the established, "mothballed" LNG facilities that essentially have zero book value. LNG supply costs are also affected by tanker transportation, in that as distances of tanker transport increase the transportation cost becomes more burdensome. Also, the estimated five to seven years it will take to build new "greenfield" LNG import plants will be a factor.

Because of the time needed for a new plant, there won't be much more than 1 to 1.5 bcf/day in new gas supply on the market in the next five year from LNG imports.

Growth of LNG imports will also be affected by plant siting difficulties within the U.S. However, there are ways around some of these challenges. For example, two new "foreign" facilities being discussed are really U.S. facilities in disguise. These are the facility proposed for Baja California, which will supply southern California, and a facility being discussed in the Bahamas, which will supply Florida by pipeline. In the longer, 10-year perspective LNG could become a serious competitor. The estimate is that gas prices of $2.50 to $3/mcf will be needed to support these new "greenfield" plants, and that is the same price range that is believed required for Arctic gas development.

An important thing to remember is that while there are "hundreds" of trillion cubic feet of new gas potential believed to exist in North America, there are "thousands" of tcf of new gas that will be available from international sources, through LNG imports.

A question was asked about whether CERA had a gas price forecast for 2010.

The response was that a 2010 price forecast will be affected by two factors, one being the long-term price of producing coal (seen as the major competitor for fuel in power generation) and prospects for an economic recession. Generally, CERA is sticking with a long-term price forecast in the high $2 to low $3 per mcf range, by 2010.

Co-chair Frank Brown suggested members of the Council introduce themselves. Brown is a former ARCO Alaska Inc. manager, retiring in 1999, he explained. He has spent eight years of his 30-year career in Alaska, and his last two positions are relevant to work on the Policy Council. One job was as president of a subsidiary, managing production of oil from a field in Long Beach harbor. The company was essentially working as a contractor for the State of California, which owned the field, and regular reports had to be made to the State and the City of Long Beach on market valuations of oil. This experience could help the Council make recommendations on ways to head off future conflicts between the State of Alaska and producers over gas valuation. Brown's second position, and most recent, was in managing development of the new Alpine oil field on the North Slope. This field has not only demonstrated the future potential of the western North Slope region, but involves new land and royalty owners such as Arctic Slope Regional Corp. and Kuukpik Corp., as well as a nearby community (Nuiqsut) and supply of gas to that community.

Co-chair Jim Sampson said he now works with the Alaska Federation of Labor in job training and development, and worked from 1968 to 1986 in construction, with more than a decade of that spent representing construction workers during construction of the trans-Alaska oil pipeline and the North Slope oil fields. After 1986 Sampson spent four years as state labor commissioner, followed by six years as Mayor of the Fairbanks North Star Borough. Having the natural gas pipeline come through Interior Alaska to provide energy, and the jobs it will create, are a real interest, he said.

Mike Navarre said he is president of his family's corporation, which owns and operates eight Arby's restaurants in Alaska. He studied economics and government in university, but his real education in politics came during his service in the state Legislature. His interest in serving on the Council is to help develop a gas project which has the best long-term benefits for Alaska.

Mike O'Connor is president of Peak Oilfield Service Co. His interest in serving on the Council is in helping follow up work on broad state policy from a previous state citizen commission, the Long-Range Fiscal Policy Commission on which two other Policy Council members, Mike Navarre and Al Adams, also served.

Bob Penney, a long-time Alaska businessman, said he has been interested in development of North Slope gas since 1976 and 1977 when he helped created a group, "OMAR" (Organization for the Management of Alaska Resources), to promote an "All-Alaska" gas pipeline (a trans-Alaska gasline to an LNG plant in southern Alaska) as an alternative to the "Arctic Gas" proposal to take gas by pipeline east from Prudhoe to Canada's Mackenzie Delta, the 1970s variant of the northern route being considered today. OMAR later became the Resource Development Council. Penney said many of the same issues from the 1970s are before the Council now, such as the most economic way to move gas to market and whether the state should take its 1/8 royalty gas in-kind.

Ed Rasmuson and his family have been in banking in Alaska for many years and recently sold the National Bank of Alaska to Wells Fargo. "Forty years ago my father told me that in my generation gas will be more important than oil," Rasmuson said. Today the Alaska Highway gas pipeline route creates great opportunities for a gas industry in Alaska, he said.

Jack Roderick said he first came to Alaska in 1954 as a Teamster, and in following years started a petroleum information and scouting service, attending law school, practicing law and engaging in oil and gas lease brokering. Most recently, Roderick wrote "Crude Dreams," a history of the oil and gas industry in Alaska.

George Wuerch, now Mayor of Anchorage, is a veteran oil and gas project manager, now retired, with years of experience in pipelines. In the 1970s and 1980s he was extensively involved in previous efforts to build the Alaska Highway gas pipeline. Besides representing the interests of the Anchorage community on the Council, Wuerch said he hopes to provide continuity with work that was done in the 1970s and 1980s on the gas project, to apply "lessons learned" earlier.

Grace Schaible, a Fairbanks attorney now retired, has been involved for years in Alaska public policy issues. Her interest in serving on the Council, she said, was in helping the State "do it right" this time, as the governor has requested.

Ken Thompson briefly described his background as a senior manager with ARCO Alaska and its parent, Atlantic Richfield Corp. He is now retired and has moved back to Alaska to live and operate his own company, a leadership development and consulting firm. Among positions in ARCO that are relevant, Thompson said his experience as president of ARCO Alaska, the Alaska exploration and production company, and later as head of ARCO's global gas marketing efforts and as part of a U.S. government effort to assist developing countries in gas and power development policy, would be most helpful in his service on the Council.

Rosemarie Maher, CEO of Doyon, Ltd., has been active in Doyon and related Alaska Native affairs for 22 years. In earlier years as president of Northway Natives (in the eastern Interior community) she was extensively involved in efforts in the 1970s and 1980s to build the previously-proposed Alaska Highway gasline. She hoped her knowledge from those efforts would be of benefit to the Council. Doyon has 12 million acres of land and 14,000 shareholders in Interior Alaska who would like to be involved in jobs and training for the gasline, she said.

Carl Marrs is president and CEO of Cook Inlet Region, Inc. and has been with the Anchorage-based regional corporation since it was formed in 1973. His interests in serving on the Council are to help develop a gas industry for the state following pipeline construction, and in helping secure reasonably-priced gas for Southcentral Alaska, because of the possibility that gas reserves in Cook Inlet may become depleted.

Jerry Hood is CEO for Teamsters Local 959 in Alaska and has been interested in development of an Alaska gas pipeline since he served on the board of OMAR in the 1970s, in a previous effort to promote an Alaska gasline. "I hope we can continue the work we started in the 1970s," he said.

Brian Davies is a retired petroleum geologist and manager with BP. "Alaska is our final home, and this is an important project for the future of the state," he said.

Bill Corbus is president of Alaska Electric Light and Power in Juneau, an investor-owned electric utility that has served the Juneau area since 1893. Corbus said he doesn't have direct experience with oil and gas, but feels his experience with the power generation and utility business may be useful on the Council.

Charlie Cole is a long-time attorney practicing in Fairbanks and a former state Attorney General. He was involved in construction efforts related to the trans-Alaska oil pipeline and will work, he said, to get a natural gas pipeline built along the highway so that an economical source of energy can be brought to the Fairbanks area.

Rhonda Boyles, Mayor of the Fairbanks North Star Borough, said she came to Alaska in the mid-1970s during construction of the oil pipeline, as a single mother. Her interest in the gas project now is not only its economic contribution to the state and her own community of Fairbanks, but the social impacts of the project. She is also a small business owner and will bring this perspective to the Council. Fairbanks is positioned well to benefit from the project if it comes along the highway, she noted. "We need not only to do it right this time, but to do it better," she said.

A general discussion among the Council members on process and procedure followed. One suggestion was that the Council adopt a procedure used by a similar oil policy council appointed by the governor some years earlier which combined a schedule of briefings with specified periods for public testimony and comment.

Council member Bob Penney raised the question on how the northern route should be handled. The Council's charter is to consider issues of the highway route, but the producing companies may argue the northern route is cheaper, he said.

Governor Knowles commented that he believed Alaska must support a route option that has the best chance of getting gas to U.S. markets in time to meet the market window, and the timeliness in meeting that demand is important in getting national support for an Alaska gas project. Knowles said he would not have gotten the support of the National Governors Conference for the project had the northern route been the only option being considered. The highway route also makes other options possible, such as, eventually, a pipeline to southern Alaska and an LNG project. "I don't see the northern route as a competitive option."

CORRECTION

THE FOLLOWING DOCUMENT(S)
HAVE BEEN REFILMED TO
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State of Alaska

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Alaska Highway Natural Gas Policy Council

AGENDA

Friday, March 23, 2001, 10:00 a.m. to 3:30 p.m.
Anchorage Sheraton Hotel

I. Call to order/opening remarks

II. Presentation from North American Natural Gas Pipeline Group

III. Presentation on the Canadian perspective
Jeff Smith, Senior Vice Pres., Public Affairs, Hill and Knowlton, Ottawa

IV. Break/lunch buffet

V. Presentation on the Federal perspective
Bob Loeffler, Senior Partner, Morrison and Foerster, Washington, DC

VI. Presentation on the State agency perspective
- A. Bill Britt, Coordinator, Joint Pipeline Office
- B. Mark Myers, Director, Division of Oil and Gas

VII. Break

VIII. Council Business – Sampson/Brown
- A. Approve public hearing/meetings schedule
- B. Discuss public hearing format
- C. Discuss subcommittee work

Alaska Highway Natural Gas Policy Council

Full Council Meeting Summary
March 23, 2001, Anchorage Sheraton Hotel

Co-chair Jim Sampson opened the meeting, along with co-chair Frank Brown. This is to be the first of two workshops intended to give Council members a greater understanding of issues around the gas project, Brown said.

Governor Knowles made opening remarks, reporting on recent activities related to the Alaska gas project. The governor testified, along with the governors of Montana and Wyoming, on legislation relating to access to public lands that was before the U.S. House Natural Resources Committee. Knowles commented that one member of the committee, who opposed ANWR opening, remarked, "why don't you folks in Alaska develop your gas first." Not to exclude ANWR, but this signifies the broad support in Congress for developing Alaska stranded gas, the governor observed. Secondly, the governor attended a conference in Calgary, Alberta along with the premiers of Yukon Territory and Northwest Territories, and offered the vision that both the Alaska Highway and Mackenzie Delta pipelines will be needed to supply markets in North America, and that a cooperative approach to do both projects is needed. "Their agenda is no different than Alaska's, in industry development and jobs. They're not in competition with us. We can work together rather than in confrontation." Knowles said the adage of the "early bird gets the worm" applies, because the first projects to deliver gas to the market face the highest probabilities of success.

As the Council took up its workshop agenda, the first to appear were representatives of the North American Natural Gas Pipeline Group *(Note: this group later changed its name to the Alaska Gas Producers Pipeline Team)*, the senior Alaska gas managers for the three producer companies involved. Robbie Schilhab of ExxonMobil Corp; Ken Konrad of BP Alaska Exploration Inc. and Joe Marushack of Phillips Alaska, Inc., who jointly manage the producers' group, appeared before the Council.

Marushack remarked that the time now appears right for commercialization of North Slope gas and that there appears to be a general alignment between Alaska's interests in developing the gas and that of the industry. The Council contains within it considerable skills to analyze issues before the state, including considerable experience in oil and gas and management of large and small businesses. People on the Council have experience in financing businesses and will know that if the producers can develop a good gas project, financing will flow to the venture. "This project is much like others you have dealt with, except the numbers are bigger," he said.

The gas treatment plant that will be built as part of the project will be the biggest of its kind in the world, but it is the smallest part of the overall project. Making steel for the pipeline will require years of effort by steel producers.

Marushack went through a standardized presentation the group has used before other forums in Alaska, highlighting key elements and goals: the large 35 trillion cubic feet (tcf) proven resource and potential for 100 tcf of future discoveries; a rare opportunity of three major oil and gas companies to pool resources with the state of Alaska to develop the project; and the outlook for gas demand growth in the lower 48. The U.S. is now consuming about 62 billion cubic feet (bcf) per day of gas, "but we

will have to find another 52 bcf/day by 2010 to replace reserves being produced and meet new demand," he told the Council.

The producers think the lower 48 is the right place to take the gas. The demand for gas (as liquefied natural gas, or LNG) in Asia is expected to grow about 8 bcf/day over the next 10 years in the high case.

Marushack also said there will be lots of competition for the North American market, from deepwater Gulf of Mexico gas, eastern Canada coal-bed methane, tight-sand gas and imported LNG. Very high gas prices of $8 to $10 per thousand cubic feet (mcf) are not good for the Alaska project because they will stimulate lots of competitive new supply. Gas prices in more "reasonable" ranges are better for the Alaska project, he said.

Robbie Schilhab, of ExxonMobil, described the producers' group organization and said the major sources of gas supply for the project, at least initially, were the Prudhoe Bay and Point Thomson gas fields on the North Slope. The group is studying two options, the Alaska Highway route and the offshore "northern" route to the Mackenzie Delta. Contracts are being negotiated with contractors to do engineering and design studies for the large gas plant at Prudhoe Bay; the possible two routes to Canada; on ways of moving the Alaska gas on to lower 48 markets through either expansions of existing pipelines or "new build" pipelines; and on a natural gas liquids extraction plant to be built at some point along the pipeline.

Ken Konrad, of BP, described technical aspects of the studies, including the scope of the gas plant at Prudhoe (it will exceed in size the tonnage of facilities built for all new slope projects in recent years), the high-strength steel needed for the all-buried pipeline and an initial plan to size the pipeline to deliver 4 bcf/day with possibilities for expansion. Construction will be much different than with the trans-Alaska oil pipeline in the 1970s, and will involve automatic welding and automated control systems to achieve levels of high productivity and integrity. It is believed that an Alaska Highway route will require three years of construction. It is possible that the northern offshore route could be built in two years.

Konrad pointed out that the "legacy" of the project will include "upstream" (new exploration and development) as well as "downstream" (gas industry processing, fuel) opportunities for Alaska. The potential 100 tcf of gas on the North Slope is the energy equivalent of 17 billion barrels of crude oil, a considerable resource.

Lee Gorsuch, a Council member, asked for the producers' reaction to Foothills Pipe Lines' comments that a 42-inch pipe size was preferable because existing industry can handle pipe of this size, and a second question involving how expansion of capacity to meet demand in Alaska can be paid for or whether it can be built into the system at the start.

Schilhab commented that the producers are looking first at the overall economic feasibility of the project. Ownership of the project and issues like how expansions will be paid for will come after the project is found to be economic. Konrad added that the group's initial screening studies of pipe size are starting at 48 inches to handle 4 bcf/day, but that the actual diameter could be larger or smaller. If it doesn't cost too much, the bias will be toward larger diameter because it means the system can then

be expanded with more compression, which requires less footprint, less environmental impact, etc. than subsequent expansion of pipe.

North Slope Borough Mayor George Ahmaogak asked about possible lost oil production in the Prudhoe Bay field, if there were commercial gas sales.

Konrad replied that this issue is of serious concern to the producers. Oil production is still the lifeblood of the North Slope industry, he said. The producers may be able to make additional investments in Prudhoe to minimize oil losses, such as accelerated drilling, injection of carbon dioxide, "or a whole mix of other projects," he said.

Following the producers, Jeff Smith, of the Calgary office of Hill & Knowlton, a major U.S. public relations firm that is under contract to the State of Alaska, gave the Council a briefing on Canadian politics and how the Canadian government will be influenced on the gas issue. Smith gave a brief description of the structure of Canada's governments and history, underscoring that Canadians have always had a deep attachment to the northern areas and issues that affect the north. It will be dangerous to allow the pipeline issue to become framed as "us vs. them" in Canada, he said, which could easily happen. It is much more effective for Alaska to communicate the commonality of interests in cooperative approaches to development of both Alaska and Canadian gas, as Gov. Knowles is doing, he said.

Smith briefed the Council on status of Native land claims in Yukon and northern British Columbia, which may affect an Alaska Highway route, and mentioned the official Canadian federal policy that the private sector will determine the best routes for northern pipelines, i.e. that it is not a matter for governmental involvement. He described which Canadian federal departments are responsible for different aspects of northern pipelines, and the backgrounds of the ministers heading those departments.

Anchorage Mayor George Wuerch, a Council member, observed that many U.S.-Canada issues were resolved by treaty in the 1970s. Is the treaty now obsolete?

Smith replied the Canadian government recognizes that conditions have changed since the treaty was signed, in technology and the level of environmental assessment, which is now more advanced in both Canada and the U.S. than was the case when the treaty was signed. "The view of Canada's federal government is that its role is to insure a smooth regulatory regime for any pipeline proposal that comes forward," Smith said.

North Slope Borough Mayor George Ahmaogak asked the status of efforts by Mackenzie Delta producers to get their own gas to market.

Smith replied he understands they are working to get their gas to market as soon as possible, and that First Nations groups along the Mackenzie River valley, which would be the route of the pipeline, have formed an organization to work cooperatively with pipeline developers.

Jack Roderick, a Council member, asked about how NAFTA (North American Free Trade Agreement) might apply to the gas project and whether other trade issues might affect the project.

Smith replied that there is a major dispute between the U.S. and Canada over Canadian lumber exports and that there are some in Canada who argue that "gas should be held hostage" until lumber and other issues are resolved. However, the prime minister has consistently said that he will fight the U.S. if there are trade disputes, but that energy will not become involved. The prime minister is keenly interested in President Bush's notion of a North American energy regime and will not allow energy to be dragged into disputes over other trade issues, he said.

Bob Loeffler, a senior partner in the Washington, D.C. firm of Morrison and Foerster, gave the next presentation to the Council.

Loeffler first outlined the major players on the federal level: the Department of the Interior, which will issue the ROW lease; the Department of Energy, which has less clear jurisdiction but is the policy arm of the Federal Government on gas pipeline issues; the Federal Energy Regulatory Commission (FERC), which has jurisdiction over gas pipelines; and Congress, which may or may not play a role with legislation.

The two federal departments will not be fully staffed at the senior levels for several months, due to the recent change of federal administration. At the moment, FERC has only three of its five board positions filled and the President may soon replace the sitting chair. In Congress, two pieces of energy legislation are in the Senate (one introduced by Senator Murkowski, the other by Senator Bingaman), but neither have provisions specific to an Alaska gasline.

Mr. Loeffler continued by saying that there is no discernable opposition in D.C. to developing Alaska's North Slope gas, but it is too early to find consensus on a route or an applicant. However, there is a fair amount of support, due to historical and logical reasons, for a southern route.

The outgoing FERC chair (the chairmanship passed from a Democrat to a Republican in January) released a report identifying issues that the federal government will face with an Alaska gasline project. This report is more of a FERC staff report than a Commissioners' report, and the new chair has not yet read the report. The report does not conclude whether or not Congress meant to apply the benefits of the Alaska Natural Gas Transportation Act (ANGTA) to projects contemplated so long after the original decision. After all, there have been many changes since 1976: wellhead prices are no longer regulated; there would be different economic impacts to the country; environmental issues have changed—the judicial limitations placed on appeals couldn't apply to environmental legislation passed after ANGTA, such as the Endangered Species Act.

ANGTA created special procedures to avoid the lengthy FERC comparison and approval hearings. ANGTA remains on the books and only small portions of it have been repealed, such as the Office of the Federal Inspector (OFI). Under Section 9 of ANGTA, all federal agencies were directed to expedite issuance of permits related to ANGTS and were deprived of authority to approve terms and conditions that would compel a change in the basic nature or general route of the pipeline project.

ANGTA is relevant today in that it either still applies or is a model for new federal legislation that would coordinate, centralize and expedite today's project.

Loeffler thinks FERC can't and won't act until some application has been submitted to them. Do they have jurisdiction to accept an application other than the one chosen by the President in 1977? FERC

believes so, but there is as yet no definitive answer to that question.

Loeffler mentioned ongoing international considerations. The 1977 treaty between the U.S. and Canada was based on a timetable that projected the pipeline would be in operation by the beginning of 1983. Does this treaty still apply?

There are many unanswered questions, Loeffler concluded, but the prospects for an Alaska gas pipeline project have never looked so good.

Council member Al Adams asked can FERC jurisdiction be bypassed by using a port authority concept for the project?

Mr. Loeffler stated that the federal government doesn't give up jurisdiction readily, and while there is an historical example of a FERC exemption applied to a gas pipeline within the boundaries of one state (the Hinshaw exemption), he has not seen a legal argument for total exemption.

Anchorage Mayor George Wuerch, a Council member, asked if the Northwest project and partners had federal and state ROW leases and, if so, are the leases transferable to private or publicly owned authorities?

Mr. Loeffler said he hasn't looked at that recently, but recollects that there is provision for transfer of federal ROW leases within the terms and conditions of the President's Decision.

Mayor Wuerch followed up by asking if the OFI concept is likely to be used again?

Mr. Loeffler replied that the position has been abolished and that he thinks this administration would be sensitive to the State of Alaska's concerns about the OFI.

Council member Charlie Cole asked if the Yukon Pacific Corporation's (YPC) permits are readily available.

Mr. Loeffler replied that YPC owns a separate series of conditional permits. A number of them must be renewed or conditions must be met. It would be an overstatement to say that the YPC project is "ready to go".

Lee Gorsuch, a Council member asked if there is any language in ANGTA about local access to gas.

Mr. Loeffler stated that Section 13B of ANGTA gives the State of Alaska authority to withdraw its royalty gas and mandates FERC issue authorizations necessary to effectuate such withdrawal.

Jack Roderick, a Council member, asked if the U.S. needs a new treaty with Canada.

There may be need for new federal legislation, Mr. Loeffler stated, and possibly a new treaty or an update of the letter of agreement between the two countries.

Lee Gorsuch asked if Foothills' ROWs in Canada are valid. Mr. Loeffler didn't know, as he doesn't practice in Canada.

Council member Jeff Feldman asked Mr. Loeffler to contrast the amount of time needed for regulatory approval for a highway project versus updating and completing conditions of the YPC project. How much further ahead are they, if at all?

Mr. Loeffler first replied that any project must meet the test of market—a project may have every permit but still not pass the "test of the market". The producers estimate three years for permitting a highway project, although Mr. Loeffler is hopeful it can be reduced to 2 years. Completing the conditions of YPC's project would take a year, Mr. Loeffler guessed, depending on the response of regulators.

Charlie Cole asked if Foothills has any binding and enforceable permits or paramount rights for a pipeline within or outside of Alaska.

Mr. Loeffler replied that no one knows. The President selected the Northwest Partnership to build the system, and that certificate can be transferred. If the certificate is still viable, then Foothills has those rights. The FERC report suggests that those rights are not exclusive, but an argument could be made either way.

Lee Gorsuch asked what restrictions there are under FERC jurisdiction that would limit the State's ability to pass terms and conditions on taking off gas, or other things the State determines to be in its interest.

Mr. Loeffler answered that the FERC certificate gives the holder a right to Imminent Domain over private lands. His firm has argued since 1975 that it gives no such right over state lands. If the Imminent Domain decision stands, he continued, it is arguable that there isn't a federal presumption of terms and conditions over state lands. However, Mr. Loeffler doesn't think the federal governmer would preempt the State with respect to state ROWs.

Jack Roderick asked if the State would have authority to regulate the tariff inside the State.

Mr. Loeffler replied, "I believe the answer is no."

Bill Britt, the state pipeline coordinator, described the functions of the state-federal Joint Pipeline Office (JPO), which includes several state and federal agencies who function together to oversee pipeline operations and review new applications. State agencies within the JPO have formed a group within the office working solely on the gas pipeline, and it is believed the federal agencies will similarly form a subgroup to work on gas, joining the State. Of the federal permits required, the Environmental Impact Statement is likely to take the most time. The streamlined EIS for lease sales in the National Petroleum Reserve took 18 months, so a gas pipeline EIS would require a similar period, or longer. Among State authorizations, the State pipeline right-of-way lease will require the most time, possibly nine months. State air quality permits (the State has air quality jurisdiction under the federal Clean Air Act) will also take time. Another function of state and federal agencies in the JPO is the review of engineering and technical data provided in support of a pipeline application.

It is important for agencies to work as much as possible with potential applicants for pipeline projects before the application is submitted so that the application is as complete as possible when it is

submitted. This will speed the authorization process. What is unusual with the gas project is that while the JPO's functions on trans-Alaska oil pipeline oversight are paid for by the TAPS system, there is no such payment mechanism, as yet, on gas projects. There are several groups who are working on new or renewed permit efforts on gas projects, including the producers' group, Foothills Pipelines and Yukon Pacific Corp. The state is negotiating cost-reimbursement agreements to cover most expenses related to these pending applications, but it is appropriate that some costs should be paid by the State, from State general funds. About 10 percent of the JPO's funds come from appropriation of general funds from land rentals for pipeline rights-of-way, but this is the first time that the office has been faced with a great deal of work related to anticipated new applications. This is why increased general fund appropriations from the Legislature have been requested. Britt warned that recruiting is a major challenge for his group, in the face of increased demand for engineers and other specialists by industry. The JPO will also contract a lot of its work to consultants, but some types of work are more appropriately done by agency staff.

Charlie Cole, a Council member, expressed concerns about the state agencies in JPO having the resources and staff to keep up with the project and allow it to stay on schedule.

Mark Myers, director of the Division of Oil and Gas, briefed the Council on his division's outlook for future gas potential and several study projects underway related to gas development. The estimated 31 to 35 tcf of proven undeveloped gas resources of the North Slope represent 20 percent of the nation's proven gas reserves, he said. Cook Inlet has about 2.5 tcf of remaining proven reserves.

Currently the division is gathering information in four areas: potential in-state demand for gas; royalty gas valuation; effects of gas production on the Prudhoe Bay and Point Thomson reservoirs (effects of gas in oil production in Prudhoe is a major concern); and an assessment of the long-term potential undiscovered gas resource. A $50,000 "fast-track" appropriation by the Legislature on the gas drawdown reservoir effects study is underway and will be completed by the end of the year. This will lead into a longer-term, $500,000 study of reservoir effects by the Alaska Oil and Gas Conservation Commission.

The potential for new gas discoveries is very good because geological conditions in many areas, such as the Brooks Range foothills, are more conducive for gas than oil. Also, gas can be developed from lower quality reservoirs than is usually the case for oil. Thus, there are many more potential reservoir targets for gas. The coastal plain of the Arctic National Wildlife Refuge also has potential. "We know it's one of the best unexplored areas for oil, but parts of the area also have great potential for gas. It could be a world-class gas belt." There are also unconventional gas resources, such as gas from hydrates and coal beds.

Bob Penney, a Council member, asked how much more gas could be used in Alaska, and what other industries could develop if there were reasonably priced gas.

Myers said that the basic issue will be the delivered price of gas, which derives from the economics of the pipeline. The division's demand study now underway, funded at $75,000, is a screening study of potential demand and will give some indications of answers. Of the approximate 225 billion cubic feet of gas from Cook Inlet used annually, about 25 percent is used for energy, for space heating and production of electricity, and 75 percent is used for industrial purposes, either in fertilizer manufacturing or in the making of liquefied natural gas for export.

Alaska Highway Natural Gas Policy Council

AGENDA

Thursday, April 5, 2001, 10:00 a.m. to 5:30 p.m.
Anchorage Sheraton Hotel

I. Call to order/opening remarks

II. Presentation from Alaska Gasline Port Authority

III. Presentation from Foothills Pipe Lines Ltd.

IV. Lunch break

V. Presentation from LNG Sponsor Group

VI. Presentation from Yukon Pacific Corporation

VII. Council Business

VIII. Subcommittee Session I
- A. State's Royalty Share – Bill Corbus, chair
- B. Access to the gas/In-state gas consumption – Ken Thompson, chair

IX. Subcommittee Session II
- A. Alaska Hire/Buy/Build – Mike Navarre, chair
- B. Federal/International Action – Charlie Cole, chair
- C. Environmental Considerations – Peg Tileston, chair

Alaska Highway Natural Gas Policy Council

Full Council Meeting Summary
April 5, 2001, Anchorage Sheraton Hotel

Co-chair Jim Sampson called the meeting to order.

Gov. Knowles briefed the Council on recent developments in the national energy situation. The outlook is for continued shortages of electricity in parts of the country and high prices for natural gas. There have been no significant changes in the situation.

The governor attended an energy conference in Houston also attended by Canadian leaders, which was heavily attended due to high interest in the energy situation. Knowles' message to the conference was that Arctic gas - Alaskan and Canadian - can help meet the nation's energy needs. Alaska is not in competition with Canada, because new gas from all sources – the Arctic, western Canada, East Coast Canada, Gulf of Mexico and LNG imports - will be needed to meet the expected demand.

Knowles also told the Council that Senate President Rick Halford and House Speaker Brian Porter have agreed to become members of the Council.

Alaska Gasline Port Authority:

Dave Cobb, former Valdez Mayor and member of the Port Authority board, gave the presentation.

The Port Authority was created under Alaska statutes allowing separate port authorities to be formed by municipal governments. Voters in the City of Valdez, Fairbanks North Star Borough and North Slope Borough approved its creation in October 1999.

Cobb said that three guiding principles for the Authority include creation of jobs, providing gas to Alaskan communities and helping stabilize the state economy by helping commercialize stranded North Slope gas. The approach, using tax-exempt public debt financing for a portion of the project, would lower costs and dramatically increase the economic viability of a large gas project, and maximize benefits to both Alaska and the producer companies.

The three municipalities forming the Port Authority each contributed $100,000 to its startup costs, Cobb said. Yukon Pacific Corp. made a $250,000 contribution, along with a $75,000 contribution by Bechtel Corp, he said. The authority has a Memorandum of Understanding with Bechtel, under which the company did a "ground up" (i.e. original, not built on previous work) construction cost estimate, an effort that involved about 55,000 manhours of work. Bechtel has about $5 million to $6 million invested in this effort, which involves the use of state-of-the-art pipeline technology, Cobb said. The international financial consultants Taylor-Dejoung developed an economic model based on Bechtel's cost estimate.

Two other accomplishments of the Authority include obtaining a ruling from the Internal Revenue Service that the Authority is a public corporation exempt from federal income tax, and an assurance

from the Federal Energy Regulatory Commission (FERC) that a gas project built by the Authority would not be subject to FERC review, Cobb said.

The Authority contemplates financing 100 percent of the project and distributing net revenues on a formula providing for 60 percent of revenues paid to the State of Alaska, 30 percent to all Alaska municipalities and 10 percent retained by the Authority and the three municipalities that formed it. The distribution to municipalities is intended to replace state revenue-sharing, which has declined substantially in recent years. The minimum payment to any community, no matter how small, is $50,000 per year, Cobb said.

By taking advantage of exemptions from many federal, state and local taxes, a gas project built by the Authority would result in $2 billion to $3 billion in revenues to gas producers over what a privately-built project would produce, and an additional $1 billion to the State of Alaska.

Valdez has a history of promoting similar pubic/private partnerships, Cobb said. During construction of the trans-Alaska oil pipeline in the 1970s, the City of Valdez issued revenue bonds to finance parts of the Valdez Marine Terminal. The city is the owner of these facilities, Cobb said, and both Valdez and the pipeline owner companies have realized substantial benefits from the arrangement.

Questions from the Council:

A question was asked about assumptions of gas volume and throughput.

Cobb replied that the Authority believes in the "Y" concept, with one pipeline built through Interior Alaska to the lower 48 and a second pipeline branching off to an LNG plant on the southern Alaska coast. The project envisioned by the Authority would carry 6 billion cubic feet of gas daily from the North Slope to the "Y" junction in the Interior. Three billion cubic feet of gas daily would then be shipped on to the lower 48, and three billion cubic feet of gas daily shipped to the LNG plant through the second pipeline.

A Council member asked about guarantees for the bonds.

Cobb replied that the Authority would guarantee debt issued for the project. If the bond market doesn't believe the project is feasible, the bonds won't be purchased, he said.

He stressed that the Authority would own the project but would contract for construction and operation. Also, while the most financially advantageous project involves the Authority actually purchasing gas from the producers and selling it, the producers could also contract to ship their own gas through a gas pipeline owned by the Authority. The Authority could also own part of a project. For example, if the producers want to retain ownership of a pipeline to the lower 48, the Authority could build the spur pipeline to southern Alaska. "We believe the Port Authority can fit in anywhere. There are advantages without full-scale involvement," Cobb said.

A Council member asked for more information about the allocation of revenues, and a comparison of how the state and its communities benefit under the status quo, retaining their own full taxing authority (such as State corporate income tax), and the tax-exempt, revenue-distribution concept proposed by the Authority.

Cobb replied that this analysis has been done and that he would provide it to the Council.

A Council member asked why the State couldn't do what the authority proposes to do, with similar advantages.

Cobb replied that financial consultants had advised that if the State were the financing entity, bond buyers would very likely ask for backstop guarantees from the Alaska Permanent Fund. Because the Port Authority is an independent public corporation, with, under state law, no guarantees required from either the municipalities involved or state government, a bond buyer would have to look only to the project, because the Authority has no funds to guarantee bonds.

An observation by a Council member was that guarantees from the producers would likely be involved, in the form of long-term contracts to ship gas.

Another Council member observed that until very recently, producers were not involved in pipeline ownership in the lower 48. The take-or-pay contracts they signed served as guarantees to independent third parties building and operating the pipelines. This has changed in the last 20 years. Producers have become involved in riskier domestic pipeline projects built into new areas to control costs. Overseas, a model of part government and part private ownership has evolved, with governments desiring an involvement so as to be able to participate in the setting of tariffs. Producers become involved for the same reasons, and to control costs.

Another motive for producer involvement is to enjoy the financial benefits of an equity position in a pipeline, it was explained. Rate of return on a pipeline investment is typically lower than from a producing property, but it is constant, without the ups and down of production revenues (due to price volatility) and is a good source of steady cash-flow.

Foothills Pipe Lines, Ltd.

John Ellwood, vice president engineering and operations, gave the presentation.

Foothills is a joint-venture company formed by TransCanada Pipelines Limited and Westcoast Energy, two of Canada's largest pipeline companies, to participate in an Alaska natural gas pipeline project when it was first proposed in the late 1970s.

Ellwood sketched the history of the company's involvement in the Alaska gas pipeline project. Foothills was originally formed to build the Canadian portions of the Alaska Natural Gas Transmission System (ANGTS.)

Meanwhile, two "pre-built" portions of the system, from western Canada to the U.S. midwest and Pacific Northwest, were built by Foothills and are in operation today. As for the Alaska portion, as members of the ANGTS consortium withdrew from the project Foothills purchased their interest. "We saw real value in the Alaska Natural Gas Act, its Canadian counterpart and the U.S.-Canada Treaty because they will get a project done quickly. That is why we devoted extensive efforts to keep the permits alive."

Today Foothills is the operator of the ANGTS project, which has permits and rights-of-way for a gas pipeline along the Alaska Highway through Alaska and Canada. Foothills has kept all of the permits for the system in good standing, Ellwood said. The permits will have to be updated to reflect different volumes of gas and the new technology being incorporated, but the updating can be done without difficulty, he said.

The pre-built parts of the system were a gamble at the time, Ellwood said. They were built because there was no assurance that the northern part of the project would be completed (it wasn't). The pipelines were built oversized for the gas then available for shipment, and the Canadian government sought an assurance from the U.S. government that the Alaskan part would eventually be built. The assurance was given.

However, gas production from western Canada has expanded considerably and today the pre-built sections are not only full, but have been expanded five times, each expansion incorporating the latest in new technology, Ellwood said. The pre-built pipelines now carry 3 billion cubic feet per day of gas, roughly 5 percent of U.S. gas consumption.

Today the legal structure of the U.S. presidential decision, laws passed by both the U.S. Congress and Canadian Parliament, and the U.S.-Canada treaty remain in full force, Ellwood said. A 1977 conditional certificate issued by the Federal Energy Regulatory Commission also remains in effect, he said, as does a right-of-way across federal lands in Alaska and a conditional state right-of-way.

These do not give Foothills a perpetual franchise but they do give the ANGTS project a priority over any competing applications, he said.

Some are suggesting that Foothills must use only the original design specified in the existing permits, Ellwood said. "We have researched this carefully, and it is not the case. Section 9 of the (federal) Alaska Natural Gas Act gives FERC the authority to amend our certificate, as long as we don't change our basic route or the nature of our project," he said.

Another change since the 1980s was that the Office of the Federal Inspector for the ANGTS project, originally within the Department of the Interior, was moved to the Department of Energy. Ellwood said the Secretary of Energy has given assurances that the functions of the Federal Inspector would be carried out by this office should the project be revived.

A key advantage of the existing laws is that they provide for limited judicial review. "That is a very valuable asset," Ellwood said.

The company has a "pending" right-of-way application with the State of Alaska to cross state-owned lands. Foothills is now in discussion with the State on renewing work on that application.

On the Canadian side, the company has a Certificate of Public Convenience and Necessity issued by Parliament, which means only that body can revoke the certificate. Also, a right-of-way has been established across Yukon Territory which is not subject to land claims by First Nation groups. All 14 First Nation groups have signed an agreement recognizing the right-of-way, Ellwood said.

What the company does not yet have is a commercial agreement with the North Slope producers, he said, and Foothills is now devoting its energies to achieving that. "We anticipate the producers will want some part in ownership and control," Ellwood said. That isn't a problem. "We want to be part of the solution, not a problem," for the producers, he said.

The key message that Foothills would like to leave with the Council, Ellwood said, is that the expedited regulatory review system established under the existing laws and treaty constitutes a valuable asset for Alaska and the producers, as well as for Foothills, because it would allow a gas pipeline project to get through red tape very quickly.

A Council member asked if Foothills, as a Canadian company, will seek U.S. companies as partners.

Ellwood answered that his company is open to new partners but that the first priority is to get a commercial agreement with the producers.

A Council member asked the status of a lateral pipeline to the Mackenzie Delta provided in the 1980s laws and treaty agreements.

Ellwood responded that the existing laws and treaty do provide for a spur pipeline along the Dempster Highway that would join the ANGTS pipeline near Whitehorse, Y.T. That pipeline was planned when there was a moratorium on pipelines along the Mackenzie River valley because of unsettled Native land claims. Those claims are now being resolved, and communities along the Mackenzie now support a pipeline. Oil and gas companies with interests in the Mackenzie Delta are now considering a stand-alone pipeline south along the Mackenzie, so the Dempster Highway route is no longer needed, he said.

A Council member asked why the Alaska Highway "southern" route has advantages over the "northern" offshore route, if that route is shorter.

Ellwood responded that Foothills conducted a 50,000 man/hour study of the northern route and concluded that it would wind up costing about the same as the southern highway route because of potential problems with ice scour and trenching in the offshore segments, and problems of where to locate compressor stations if an onshore site is unavailable in wildlife refuges in northeastern Alaska (ANWR) and Yukon Territory. The southern route, although longer, has less risk. Also, availability of existing road infrastructure is a big asset.

Ellwood added that an additional problem facing a northern route is the commercial problem of sizing the pipeline to carry an unknown amount of gas from the Mackenzie Delta that is unproven (undrilled) at this point. In contrast the North Slope gas is a proven, confirmed resource. The problem is financing a northern route pipeline with enough capacity to carry both Alaskan and Mackenzie gas without the Mackenzie reserves defined to the point where contracts for gas shipment can support the additional investment.

A Council member asked about available capacity in pipelines from Canada to the U.S. that could connect with an Alaska pipeline in western Canada.

Ellwood responded that the existing pipeline grid in Canada has about 1 billion to 1.5 billion cubic/ feet per day unused capacity. Even if that capacity is not available by the time an Alaska pipeline is built (production from Canada is expected to increase by that time) the pipeline grid can be expanded, as it has before, or a new pipeline can be built.

Alaska North Slope LNG Project

Steve Alleman, project manager, made the presentation.

Alleman reviewed his group's progress to date in its work on an LNG export project. Phase one, completed last fall, involved $12 million expended in conceptual engineering, and commercial and market feasibility work.

This was successful in that a scaled down project was defined that would produce a volume of LNG (7 million tons/LNG annually) that might better fit into what the sponsor group feels is the available market in the Pacific. The project can then be expanded as the market develops.

However, even a scaled-down project was not deemed to be cost competitive, Alleman told the Council. The group's current key focus, in a $3 million phase two effort, is to find potential cost savings through synergy with the lower 48 pipeline project being planned by the North Slope producers. This would involve the "Y" concept, or a pipeline spur connecting in Interior Alaska that would carry gas to a southern Alaska LNG plant. This would shorten the distance of new "stand alone" pipeline. The lower capital cost might improve the project's economics but whether it would be enough is still uncertain.

Alleman told the Council that his group expects to conclude internal studies on an environmental assessment of the Cook Inlet route by the end of April, and to have cost estimates for a project that links with the lower 48 pipeline as early as mid-June or July.

A Council member asked about any benefits of public financing or public ownership.

Alleman said his group's analysis so far is that no compelling advantage is presented in a "public/ private partnership" with an entity like the Alaska Gasline Port Authority (meaning a project partly owned by both industry and the Authority). He added, however, that full public ownership of a project that can fully realize federal tax advantages may be different. Further discussions with the Port Authority are planned.

To illustrate the challenges the LNG project faces, Alleman showed a slide to the Council that compared estimated capital costs of other proposed LNG projects, including proposed expansions and new "greenfield" (entirely new) projects, like Alaska, that are competing for the expected new demand in Asia. Figures in the chart are based on published information, he said.

The chart shows the average capital cost among the competing projects, per million tons of LNG delivered yearly, range between $225 million to $250 million per million tons of annual LNG delivery. The estimated cost of the Alaska project, with a stand-alone pipeline (i.e. without the link to the lower 48 pipeline) ranges between $610 million to $790 million per million tons delivered. The 800-mile pipeline (in the case of a stand-alone pipeline) is about $300 million per million tons per year, or

40 percent to 50 percent of the project total unit cost. The pipeline is a huge challenge for the project when compared with its competitors, which are at tidewater, Alleman told the Council.

(Note: Three of the LNG sponsor group's four members are involved in lower 48 pipeline studies: BP, Phillips and Foothills.)

A Council member asked why the existing Phillips LNG plant at Nikiski couldn't be expanded, in a case where a pipeline went to Cook Inlet.

Alleman replied the group continues to look at that, and has not ruled out exploring possible synergies there.

A Council member asked about the economics of ocean shipping of LNG. With Phillips looking at importing LNG from Australia to the U.S. West Coast, wouldn't Alaska, with a shorter shipping distance, be as or more competitive?

Alleman replied that his group had compared published estimates on "total cost of service" (including shipping) from Australia to California, and penalized the Australian service with the need for additional ships because of the longer distance. The Alaska project, in shipping LNG to California, still wasn't as competitive, he said, primarily because of the 800-mile Arctic pipeline that an Alaska project must overcome.

A Council member observed that some of the existing LNG projects in southeast Asia can be more competitive than a new Alaska project, even with a longer shipping distance, because the LNG tankers are already built and in service. He asked for more information on the total cost of service of supplying LNG from Australia compared with estimates for an Alaska project, which is one quarter of the distance.

Alleman said he would get the information to the Council on shipping distances.

Yukon Pacific Corp.

The presentation was made by Jeff Lowenfels, president and CEO of Yukon Pacific.

Lowenfels said there are three "myths" about an LNG project, that there is "no market," that LNG is not an option and that the overland (lower 48) project is the only option. Alaska gas does face challenges because of its remote location and competition from other LNG projects, so any project from Alaska must be big to achieve economies of scale.

Despite all the work on gas over the years, the producers were not in a position to sell gas until June 2000, when the realignment of ownership in the Prudhoe Bay field changed conflicting priorities among the field owners, mainly three major producing companies.

Yukon Pacific has done extensive work on permits over the years and has secured the major "deal-killer" permits, Lowenfels said. In comparison, it will not be easy to permit the Alaska Highway route with the existing requirements of U.S. and Canadian laws on a highway pipeline, he said.

As for market demand, several studies, including independent U.S. groups like Standard and Poors, feel Asian demand for LNG will grow sharply. Estimates by private industry within the three Asian nations that are most likely markets for Alaska gas, Japan, Korea, and Taiwan, show strong future demand. Government estimates are lower because they assume more power will be supplied by nuclear plants, an assumption private industry discounts, Lowenfels said. India and probably China are probably not markets for Alaska because those countries can be supplied more economically by producers in Southeast Asia and the Middle East, but growing demand for LNG in both countries will take supply off the market, indirectly helping Alaska.

Lowenfels showed a chart showing results of two studies by engineering groups, one by Willbros Engineering and Micheal Baker Jr., and a second by Kellogg Brown & Root and Air Products and Chemicals, Inc. The estimates showed a "startup" project delivering 9.2 million tons/year of LNG could be built for $6 billion (2000 dollars), expanded to 13.8 million tons/year with an additional investment of $1.1 billion, and expanded again to 18.4 million tons/year with an additional $1.2 billion investment.

The total "cost of service" to Japan, including shipping, at a "low" case of $1.99 per million British Thermal Units (Btu) delivered to a "high" case of $2.91 per million Btu delivered. This appears attractive in the context of estimates by Tokyo Gas that it will contract LNG for $3.88 per million Btu between 2005 and 2010. "Our numbers work," said Lowenfels.

In discussion following the presentation, Lowenfels said YPC was shocked to discover that the assumptions used in the Purvin & Gertz (a consulting firm relied on by industry and the State) study for LNG relied on generic "off the shelf" data rather than estimates compiled by YPC itself. The effect is to understate the benefits of an LNG project, Lowenfels said. YPC is now discussing the report with Purvin & Gertz, and is hopeful that a more up-to-date "apples to apples" comparison can be made.

Lowenfels urged the Council to question why the "highway" is its mandate. Yukon Pacific has been working on an LNG project for many years, but was not consulted, he said. He said he didn't know what information the Administration relied on in making its decision in favor of the highway route, but he suspected it was the Purvin & Gertz study.

A Council member observed that he has always favored access to multiple gas markets, since individual markets will always cycle up and down. He asked if the lower 48 pipeline now being planned helps Yukon Pacific's project. Why doesn't YPC plan a smaller project, sized to fit the market, building off the larger pipeline?

Lowenfels replied that YPC had always built in an assumption of size that would allow a pipeline to the lower 48 to branch off at Delta. He said his company also favors some form of transparency (clear, predetermined procedures) for gas offtake, if not public ownership.

A Council member asked if YPC sees a higher wellhead price for gas from an LNG project, why Phillips (lead company in the industry LNG consortium) doesn't also see that.

Lowenfels replied that individual companies may have other projects with higher rates of return, fewer partners to deal with or complexities in putting a project together, or combinations of all those. There

may be other factors affecting Phillips' decision to participate in a project to import LNG from Australia rather than Alaska, such as a possible deadline on a concession in Australia.

A Council member replied that it seemed odd that Phillips, with an ownership interest in Alaska gas and a motivation to commercialize the asset, doesn't see a return similar to than in Australia, which is more distant.

Lowenfels replied that projects compete for funds, and investments go to the project with the highest return and fewest headaches. "I think that's what is going on here," he said.

A Council member asked if there wasn't a danger in proceeding on a parallel track with the pipeline to the lower 48.

Lowenfels replied that he has no confidence the lower 48 pipeline will really proceed. Even the companies involved say they're not sure they really have a project, he told the Council. That is why YPC is continuing to work on its own project. "We hope it (the lower 48 pipeline) does go, because we can easily piggyback on it. But we can't stop our work to wait for them," Lowenfels said.

The lower 48 pipeline, and the governor's decision to support it, has been a setback for Yukon Pacific, however. It sends a message to potential buyers in Asia that Alaska gas might not be available. That is why the senior gas manager from Tokyo Gas came to Alaska a few weeks previous, to tell state and community leaders that his company is very interested in North Slope gas.

Lowenfels also observed that discussion of a 6 billion cubic feet/day gas throughput for a project (in the Port Authority's case) is too high. It would deplete the only current North Slope reserves in production in nine and a half years. Lowenfels said that only current production is available today. There is no assurance any other fields will be opened and hence only the 21 trillion cubic feet left in the Prudhoe Bay Unit is available for any project. YPC's project assumes a lower throughput rate of two billion cubic feet/day, which can be sustained for a much longer time.

A Council member asked Lowenfels' opinion of a gas reserves tax (a state property tax) on undeveloped gas on the North Slope. (The proposal has been made by a state legislator.)

Lowenfels replied that the idea was interesting and may be appropriate.

Alaska Highway Natural Gas Policy Council

AGENDA

April 18, 2001, 5:00 p.m. to 9:00 p.m.
Chena River Convention Center, Fairbanks

I. Community Reception

II. Opening remarks from Mayor Rhonda Boyles

III. Opening remarks from Governor Tony Knowles

IV. Presentation from Commissioner Deborah Sedwick

V. Presentation from Foothills Pipe Lines Ltd.

VI. Presentation from Ken Thompson on "The Hub" concept

VII. Public testimony

Alaska Highway Natural Gas Policy Council

Fairbanks Public Hearing Summary
April 18, 2001, Chena River Convention Center

Co-chair Jim Sampson opened the hearing. Brief presentations were made by Deborah Sedwick, Commissioner of the Department of Community and Economic Development, on an overview of the proposed gas projects; Council member Ken Thompson on his proposal for gas trading "hubs" in Alaska with pre-arranged agreements for access to natural gas; and Curtis Thayer, of the gas producers' project group.

Members of the public were invited to speak:

Buzz Otis, representing the Fairbanks Chamber of Commerce gas committee, suggested a major issue the Council should focus on is pricing of gas, clearly defined access rights. A small business, a propane distributor, for example, should be able to gain access without onerous rules being applied. A pricing mechanism should be established that is the North Slope netback (wellhead price) price plus cost of transportation to Fairbanks.

Nadine Hargesheimer, representing the Fairbanks North Star Borough, told the Council that Fairbanks is a non-attainment area on carbon monoxide but the Borough is working closely with the state Department of Environmental Conservation to get the Environmental Protection Agency to "stop the clock" on sanctions. The Borough will do everything in its power to make sure provisions of the Clean Air Act, as they apply to Fairbanks, do not impede construction of a natural gas pipeline.

The Borough is concerned, however, with the enactment of state law by the Legislature which allows the State to negotiate away municipal taxing powers on a gas pipeline. Borough assembly members are uncomfortable that the State could use municipal taxes as a bargaining chip, without any direct participation by municipalities under the terms of the law.

Bert Bell, president of Ghemm Co. and head of the Associated General Contractors, expressed concern about sufficient manpower for a pipeline construction project. It's important that the pipeline's labor needs be known as soon as possible. It may be possible to spread out other projects so that all the work does not come in one peak period.

Training programs have to be underway very soon, as it takes four years to train to journeyman skills in many crafts that will be needed on the pipeline. The trans-Alaska oil pipeline had a tremendous impact on the labor force. "It killed the rest of the industry for about five years," Bell said.

Steve Ginnis, president of the Tanana Chiefs Conference, told the Council his organization represents communities across an area 235,000 square miles and 17,000 people. The nonprofit manages 220 programs and employs 500 people.

The natural gas pipeline project is being watched closely by tribal groups. The gas represents, in energy value, about 50 percent of the original recoverable reserves in the Prudhoe Bay field. The pipeline project has the potential to do a lot of good if it is done right.

It could employ a lot of people, and it's important that it be done right. The three to five years of construction have the potential for an enormous economic boost to the region's infrastructure, including schools and health facilities. Thirty years ago Alaska Natives supported the first pipeline and we support this one, too.

However, the route does cross Native lands. It will run for miles through our neighborhood. We will want assurances of planning, performance criteria and the dissemination of information. It is important that our villages be represented on the planning committees. We would also like the pipeline to serve our communities, to help reduce energy costs. The crossing of the Yukon River represents an opportunity to transfer the benefits upstream and downstream, improving living conditions in the region.

Jay Quakenbush spoke, representing the Fairbanks building and construction trades unions, 14 unions representing 9,500 experienced construction workers that the unions bring to the table. We feel this resource must come through the Interior so Fairbanks can make use of its energy. We feel the best way to promote Alaska hire is to promote and negotiate a Project Labor Agreement so that hiring is done through the halls these unions represent. Each union gives preference to Alaskan workers. Nine of the 14 unions in the council are headquartered in Fairbanks, and the other five are headquartered elsewhere in Alaska. It's the best way to insure that this money stays in Alaska and creates careers for local people.

No other organization has reached out to help train Alaska Natives like unions have done. We have demonstrated this through projects like the recent Marriott Hotel construction in Fairbanks and the Alaska Native hospital in Anchorage.

We feel we can supply a significant Alaska workforce but we need a commitment to start training. It takes 8,000 hours of field work and 10,000 hours of classroom time to produce a trained worker. A Project Labor Agreement is the best way to accomplish this.

Paul Metz, Professor of Geological Engineering at the University of Alaska Fairbanks, told the Council that private sector mineral exploration, the state of Alaska Division of Geological and Geophysical Surveys and the U.S. Geological Survey have identified 148 major mineral occurrences throughout the state.

About 10 percent of these, or 15 mineral occurrences, are located near the corridor that will be used by a natural gas pipeline through Interior Alaska. The gross value of these minerals are estimated, at a 99 percent probability (conservative case) at $45 billion, and $157 billion at a 50 percent probability.

In comparison, using the same valuating methodology, the gold resource at the Fort Knox Mine near Fairbanks has a value of about $2 billion. It now employs 250 people. The economic and employment impact of developing these mineral resources could exceed that of Prudhoe Bay. These new mines could employ as many as 20,000 people.

The largest single cost of mining is energy. An example of what inexpensive energy has done to help create a mining industry can be seen in South Africa, where hydroelectric power is available. The economic impact has been immense.

Howard Mermelstein, tribal administrator, agrees the pipeline should come by the southern route, but that it is important that tribal communities along the route be protected or otherwise compensated for impacts. While there will be a tremendous positive economic boost, including new taxes and government revenues, the tribal organizations are left to deal with the negative impacts. It is only reasonable that the tribes also realize some benefits. There needs to be tribal government representation in the planning for the project.

Chief Patrick Saylor, Healy Lake, told the Council that tribal organizations in his region are now wrestling with impacts of sports hunting and tourism. They support Stevens Village position that tribes should receive benefits.

Randy Mayo, of Stevens Village, told the Council that (pipeline construction) could heavily impact tribal governments. Years ago Stevens Village was one of six villages which filed a lawsuit that held up the oil pipeline over the issue of unsettled Native land claims.

In the 1930s the community had unsuccessfully petitioned the Secretary of the Interior to create a tribal trust land reserve in the area. In the eventual passage of the Alaska Native Claims Settlement Act (ANCSA) and the Alaska National Interest Lands and Conservation Act (ANILCA), the tribal interests were sidelined. Tribes lost 80 percent of their tribal land base. In relation to the lands given up, ANCSA was very inequitable. If a natural gas pipeline comes through the existing corridor, the tribes need a seat at the table.

Dean Owen, Director of the Fairbanks Industrial Development Corp., said he favored the "southern" (Alaska Highway) route because it would have the least impact on new land and would create more jobs. It is important, however, that Fairbanks have access to gas delivered along a southern route, and that it be priced favorably. He also urged that the state pipeline coordinator's office be located in Fairbanks because of the proximity to the gas pipeline. It would save money. Also, the agencies that are part of the Joint Pipeline Office, such as the departments of Natural Resources and Environmental Conservation, all have offices in Fairbanks.

He said that it is important that the state permitting agencies be able to hire adequate people to be able to keep up with the producers' permit schedules.

Russell Forest, a Fairbanks resident, said he is encouraged by the "proactive" role the Council is taking in working with communities, including the environmental community. The result will be to make this a project the whole state can get behind. Natural gas is a fuel for fuel cells, and its use is being demonstrated at the Anchorage post office. Availability of gas will allow on-site power generation to really take off, in applications at schools and hospitals. With all the jobs the gas pipeline will produce, it may take the heat off ANWR.

Paul Woodman, director of the Interior Weatherization, urged the Council to consider imposing a tax on pipeline gas throughput that would fund an endowment for residential weatherization and energy conservation. It would be a fine example to set for other states. Conservation is one of the fuels of the future.

Keith Hand, of Fairbanks Natural Gas Co., said his company is the certified natural gas utility in Fairbanks and has been in business since 1998. The company trucks liquefied natural gas from Anchorage, and now serves 200 customers through 30 miles of distribution lines. Another 15 miles of lines will be laid this summer, adding 150 customers. Fairbanks Natural Gas estimates that 10,000 residential customers in the Interior could be served with gas. The annual requirement would be about three to four billion cubic feet for residential heating, not electrical generation. This is one day of throughput for the pipeline. There are several points to be made: one recurring theme is the need for a tap on the pipeline to allow access to gas, not only at Fairbanks but at Delta and Tok. Where it is economically feasible, a tap should be allowed.

Second, prices for gas should be based on the netback using a tariff-based methodology. The state should also take its royalty gas in-kind. Third, there will be a need for infrastructure. Only a fraction of Fairbanks is piped for gas. Other communities are not ready. There's also discussion of gas service to communities along the Yukon River, by LNG distributed by barge.

Ryan Colgan, of Fairbanks, said a major North Slope gas project has been discussed for decades, with no success. Today the price of gas in Chicago is $5 per thousand cubic feet and $12 in California. There is some question as to whether these prices can be sustained. But why are Phillips and Chevron talking about importing LNG into California and BP expressing interest in building a west coast LNG terminal? At the same time, Tokyo Gas Co. was in Alaska recently expressing interest in Alaska gas. What is the State's policy?

Roger Burggraf expressed support for an Alaska Highway route, indicating it was more environmentally sound and assured more jobs for Fairbanks and new sources of energy. It also provided the possibility of a spur line to Valdez or Anchorage. The highway route would also promote more in-state industry. He couldn't see the northern route as being feasible.

Bernadette Pagel, a Fairbanks resident, expressed support for the gas pipeline. Her son is studying computer science and pipe welding at the university. She also urged the Council to consider a pipeline right-of-way with enough room for a railroad track. She also noted Senate Bill 158, pending in the Legislature, which would study state ownership of the pipeline. This is a good idea, but she would like to see the concept extended to the Permanent Fund owning part of the pipeline rather than having most of its money in the stock market.

Ross Coen, a Fairbanks resident, told the Council that skepticism can be a virtue. He had three questions for the Council: first, how the governor can decide the "highway" route is best without having the data or information to support the decision; second, why the Gas Policy Council and the Administration are relying on advice from Cambridge Energy Research Associates, the same group which said the BP-ARCO merger was good for Alaska; third, are producers willing to make gas available for use within the state? If not, Alaskans must have the spine to jerk back the leases or impose a gas reserves tax.

Steve Haagenson, of Golden Valley Electric Assoc., said Fairbanks enjoys some of the lowest rates for electricity in the state with a diversification of fuel sources, including coal and fuel oil, and access to hydro and gas-fired generation through the Anchorage-Fairbanks intertie. There was some thought given to providing power along the oil pipeline but there was little infrastructure, so oil is used to generate power for TAPS. He supports Ken Thompson's proposals for a hub for gas offtake and urged

the Council to pursue the ideas Thompson has put forward. He also endorsed the State taking its royalty gas in-kind and developing a statewide energy plan.

Allen Todd, of Doyon Ltd., told the Council that the corporation he represents has 14,000 shareholders. He endorsed building the pipeline along the highway, as this route would benefit the Fairbanks area economically. Two of Doyon's business enterprises, Doyon Drilling and the Doyon-Universal joint venture, do significant work for the petroleum industry, and half of Doyon's profits are distributed to shareholders. He noted that new revenues from natural gas could be part of a long-range fiscal plan for the state, and that availability of natural gas in the Interior could energize economic development.

Tim Sharp, of Laborers Local 942, said that his union has 1,000 trained workers ready for oil-related work or related construction. The unions have also taken the lead in working with tribal groups on training. He appreciates that the oil companies must examine all possible routes, but at the end of the day the decision must be for the highway route. He noted that the governor did get plenty of input before making his decision to support a highway route. There were lots of letters and phone calls encouraging the governor to make that choice.

Mark Zoetar, of Fairbanks and a member of the Operating Engineers, has just completed a job at Clear and spent two winters on BP's Northstar project. The performance of Houston Contracting and other contractors on the Northstar pipeline is an outstanding example of trained Alaskans working successfully together to complete a project in a harsh environment. The operation was so clean "we could have eaten off the ice." When the gas pipeline is constructed some people will have to be imported to fill jobs and it is important to insure that proper training is done to insure a qualified workforce.

Jerry Isaac, of Tanacross, told the Council that his community in the eastern Interior is very excited and supportive of a gas pipeline along the highway. The community has high rates of social and economic problems, and he hopes to maximize the benefits of partnerships in working on the project.

There are also concerns. The pipeline route could be as close as a mile from the community. "Construction will definitely affect my village." Cooperation is important to insure the community benefits from the project.

Faye Ethridge, of Salcha, said that as a carpenter and mother she welcomes the gas pipeline. "My brothers and I look forward to working on it, and as a mother I want to see my grandchildren living near where I live." She urged the Council to recommend "hubs" for taking gas off the pipeline for regional development projects, and for the Council to press for more vocational training so that young people now 12 to 16 years old will have the skills to work on projects that can result as a result of the hub. She also hoped natural gas can ease high energy costs in Interior Alaska. "It's disheartening that people in Anchorage pay less for gasoline than it costs me to fill up my truck right outside the Williams refinery at North Pole."

Frank Chapados, a Fairbanks businessman, related his experience in the early 1970s forming a partnership with other businessmen to do pipeline support work, as an example of how local firms can take advantage of economic opportunities when they are presented. "Fairbanks at that time was a

small town, but we managed to put it together. We performed a real service. At one time we had over 1,000 people working for us. If you give Alaskans the opportunity to perform, they will perform."

He said the State should consider investing in the pipeline. "We should do something, and not just let the pipeline go by and lose the opportunity."

Donna Robertson, of Fairbanks, told the Council she has been in business in the community for 30 years and feels that we won't be able to keep our brightest children in the state unless there are meaningful jobs. We need to train as many people as possible, and to employ as many as possible, as opportunities develop from a gas pipeline.

Wendy Lee, a Fairbanks resident, told the Council she has been a Fairbanks resident since September. She urged the Council to seek training for as many people as possible. "Don't give the jobs away."

Fairbanks resident Harry Pugh told the Council that he supports the gas pipeline coming through the Interior. He said he has worked on the slope and noticed that while there were few Native workers in the early years, Native participation in the workforce has picked up. He urged the Council to support hiring of Alaska Natives for a gas pipeline.

Alaska Highway Natural Gas Policy Council

AGENDA

May 17, 2001, 6:00 p.m. to 9:00 p.m.
Kenai Merit Inn

I. Meeting call to order/Welcoming remarks

II. Presentation from DNR Commissioner Pat Pourchot

III. Presentation from Cook Inlet Pipeline Terminus Group

IV. Public Testimony

Earlier in the day, the Council toured the Phillips LNG Plant, the Agrium Fertilizer Plant and the BP GTL Test Facility.

Alaska Highway Natural Gas Policy Council

Kenai Public Meeting Summary
May 17, 2001, Kenai Merit Inn

Co-chair Jim Sampson opened the hearing. State Resources Commissioner Pat Pourchot gave the Administration's presentation on the natural gas pipeline, potential employment, the future demand for Alaska gas and possible in-state uses for energy or feedstock for industrial development. Curtis Thayer, representing the producers' group working on the gas project, presented an overview of the companies' study project, including information on contracts recently awarded.

Mike Navarre, speaking on behalf of the Cook Inlet Pipeline Terminus Group, made a presentation to the Council. The group was founded 18 months ago with two primary goals: ensuring that as gas commercialization efforts proceed for North Slope gas, the Cook Inlet infrastructure is not forgotten; and that use of state royalty gas be managed in a way that benefit regions of the state with major population centers.

The Cook Inlet Terminus Group has met with many communities in the region and has a broad base of support for the concept of a pipeline coming south from Fairbanks to Southcentral Alaska.

Cook Inlet has existing gas facilities, a trained workforce and access to marine transportation facilities for moving products to other Alaska communities. Gas reserves in the Cook Inlet area are also declining. Fifteen years ago there was a 55 year supply; now that is down to 13 years. Exploration for new gas is just now getting underway.

Our focus is on the long-term. Seventy percent of Alaska's population lives along a route of a gas pipeline to Cook Inlet. It's the population and economic base of the state.

The economy needs room to grow, too. There is space for gas-related facilities in Nikiski, in the Matanuska-Susitna Borough and other places along the railbelt. "I wenfels didn't tell you they'll have to knock down a mountain to build a terminal." (This is a reference to Yukon Pacific Corp. Jeff Lowenfels' presentation to an earlier Council meeting, on behalf of his company's work on a gas pipeline route to Valdez with a terminal at Anderson Point.)

A Cook Inlet route also protects jobs. The Agrium fertilizer plant is the single largest tax-paying facility on the peninsula and the largest private employer. The inlet itself is also wide and safe for marine navigation. At its narrowest point it is 12 miles wide. One thousand shiploads of liquefied natural gas have been safely shipped from the Phillips/Marathon LNG plant at Nikiski.

It appears now that our first opportunity to commercialize North Slope gas will be to ship it to the lower 48 states. But this could change fast.

There might be other gas supplies made available to the lower 48. So, we want to ensure that we're ready for any changes in market conditions. Market diversity is important to Alaska. Shipping LNG from southern Alaska gives us access to the U.S. west coast as well as overseas markets. Cook Inlet has 30-plus years of experience shipping LNG, space for industrial expansion and the potential for

diversification of markets. The Cook Inlet Pipeline Terminus Group will not stand in the way of any route. All we want is to ensure that Cook Inlet is considered. If we just send our gas down the highway, we're just exporting our resources like a third world country. We would like to see a spur line to Southcentral Alaska, if not the main pipeline, considered.

Mayor John Williams of the City of Kenai welcomed the Council to the community, noting that the Alaska petroleum industry got its start on the peninsula years ago. Alaska didn't have a lot going, economically, at statehood until oil and gas activity in the inlet brought jobs and revenue to the State and local governments.

Use of natural gas has been very important. In my community, three of four major industrial facilities are based on natural gas. My message to you is that we must do everything possible to ensure as much of the gas is used in-state as possible, for space heating and to develop as many products as possible from natural gas.

There are opportunities in Kenai for gas-to-liquids plants. The BP test plant is a first stepping stone in using natural gas to make thousands of products.

I would like to see a state law that requires as much of the gas as possible to be used in-state, to process this raw resource to benefit the most number of Alaskans.

John Lau, of Enstar Natural Gas, told the Council his company supports the highway route. Enstar has a long record of service and reliability in natural gas distribution, he said.

Dan Grove, speaking on behalf of the Alaska Support Industry Alliance, told the Council that he has seen the benefits the industry has provided to Alaska. The time is right to bring North Slope gas to market, but we need to act quickly. Natural gas from the North Slope will bring many benefits, jobs and opportunities, and affordable energy.

The highway route offers an opportunity to avoid construction through undeveloped areas. Any pipeline, however, should allow opportunities for a spur line to Kenai.

Jack Brown, representing himself as a father as well as a former assembly member, told the Council that even with economic development in the Kenai areas there are still families that are "hurting" in the area. Sixty percent of the children attending elementary school in the Nikiski area qualify for the federal school lunch program. "We really need to develop a stronger economy for Alaska. I strongly support a spur line to Southcentral to stimulate the economy."

Harry Crawford, a state legislator, represents 16,000 constituents in Anchorage. He told the Council he is an ironworker. He came up the Alaska Highway when he was 22 to work on the trans-Alaska oil pipeline. "We were going to build the gasline right after the oil line, but we're still waiting. Anything I can do as a legislator to get the show on the road, I'm willing to do. Let us know."

Robert Peterkin told the Council he is a third generation Alaskan. He is a supporter of the pipeline and likes the highway route. "My way is the highway" is a good motto, and he hopes we can see a spur line built to Kenai.

Dan Chay, a Kenai resident, told the Council he hasn't heard much discussion of Alaska gas in context of global oil production. He cited some geologists' opinions that global oil production will peak in the next five to 10 years, which will cause the value of Alaska's petroleum (oil and gas) to go up. Many people have observed that there are 13 years of gas reserves left in the inlet. With our inlet gas production having peaked and in decline, it should affect our choice of how to direct the transportation of our gas, to Canada or here.

Chay cited known reserves of major inlet fields and noted that 80 percent of the reserves of the large fields have been produced, and 50 percent of much of the remaining productive fields. This suggests that the inlet fields have passed their peak. Given this, a pipeline route through Canada is not a good idea. If our concerns are for the interests of Alaskans, not the oil companies, then we should have a pipeline that brings the gas to Alaskans.

Blake Johnson, Kenai resident, told the Council that when oil production modules were built recently at Nikiski (for the Alpine oil field, on the North Slope) there was a "job fair" to inform local people of job opportunities. At the same time there were ads in Los Angeles newspapers advertising for workers for the project.

Johnson told the Council he was appalled that 60 percent of children in the Nikiski school (cited by an earlier speaker) qualified for public assistance. "Most of these people are working. They should be paid more money," he said. Jobs should be paid Davis-Bacon wages. At 40 hours a week and $25 an hour, annual pay is about $50,000. "It takes every bit of that to live up here," he said.

Keith Huss, Kenai resident, said he has been working with oil and gas industry supply firms in Alberta, and they are now very busy drilling their own gas reserves. "If we don't step up to the plate to produce our gas we'll miss the bus. Canada will fill this supply gap (in the lower 48). I hope we can get this done."

In discussion among the Council and members of the public present, co-chair Jim Sampson observed that it was helpful for the Council to tour the LNG, Agrium and GTL plants to get an understanding of what has been happening on the peninsula.

Mike Navarre, a Council member, made the comment that compressed natural gas or other technologies may allow gas to be delivered to rural Alaska, but that deliverability will be heavily dependent on port access.

State Resources Commissioner Pat Pourchot remarked that the gas pipeline being planned for the lower 48 would deliver up to 4 billion cubic feet a day through a large diameter pipeline. All uses in Southcentral Alaska total about 200 million cubic feet a day. The amount of gas moving through the large-diameter pipeline is 20 times the amount consumed for all uses in Southcentral. To make a pipeline economic, large volumes of gas will be needed to lower unit costs.

Jim Sampson said he appreciated comments regarding opportunities for jobs. "We want to ensure that our children have opportunities to work here. We're also interested in good-paying jobs, not minimum-wage jobs."

Carr Marrs, a Council member, said part of the Council's task in reporting to the governor will be to note the sustained need for gas in Alaska to help sustain the state's employment base, not just sending the resource to the lower 48 states. The volumes of gas being discussed can produce opportunities for additional employment, including many high-paying jobs. "There are a lot of things we can do."

Bob Penney, a Council member, observed that 25 years ago most Alaskans favored a pipeline through Fairbanks to tidewater. If we want to take our royalty in-kind, is there any possibility of using the Alaska Railroad right-of-way?

Carl Marrs said that the railroad offered one right-of-way and that utility corridors were also available. "All of us agree that at present rates of Cook Inlet gas production and consumption, we will probably see problems beginning in 2006-07 without finding additional resources. Estimates are another 1.3 trillion cubic feet could be discovered. It will be more costly, particularly if it is offshore. Drilling offshore in some areas may be essentially impossible, due to environmental constraints."

Ed Rasmuson, a Council member, recalled that his father, Elmer Rasmuson, observed 40 years ago that natural gas has more potential to develop the state than oil. He said a gas pipeline along the highway route, with a possible spur to Southcentral Alaska, should be a must. There could also be possibilities for a small spur line from the highway pipeline to Haines, he said. Rasmuson also said the question of whether Alaska should be a part-owner of a gas pipeline is important.

Jack Roderick, a Council member, said he thinks there will be more gas found in Cook Inlet. He added that agreements to keep as much of the gas in-state as possible should be an important part of negotiations with producers.

Mike Navarre pointed out that if gas is taken in-kind and used to encourage economic activity, there are also costs to the State that result. "We're taking gas that would generate revenues to the treasury if the gas is sold in-value to producers and using it to create additional demands on public services. We need to develop alternative revenues to the State, through taxes or contributions from the Permanent Fund."

Mayor John Williams, of Kenai, said a few months ago he attended a meeting with other mayors of the municipal Port Authority, during which information had been presented on the capacity of gas transmission systems in Canada. "If the Canadians beat us to the use of that capacity, does it mean we have to build a pipeline all the way through," to the U.S. markets?

Curtis Thayer, of the producers' group, explained that his group is studying the "B to C" pipeline options, the capacity of existing Alberta to U.S. transmission.

Council member Carl Marrs asked about the maximum existing capacity in Alberta to U.S. pipeline systems. *(Note: Information on this subject was included in a presentation given by Cambridge Energy Research Associations at the Anchorage Public Hearing on May 24.)*

Council member Bob Penney observed that if the one-eighth state royalty gas is taken in-kind and used in-state for other purposes, it would reduce the amount of gas throughput available to finance the main pipeline. This would increase costs of transporting the other 7/8 of the gas.

Scott Heyworth, an Anchorage resident, told the Council that 4 billion cubic feet a day of gas moved for 365 days per year, would move about 1.46 trillion cubic feet per year, moving all of the North Slope's current estimated reserves of 35 trillion cubic feet in about 24 years. Also, the existing treaty

with Canada, agreed on when the Alaska Natural Gas Transmission System was negotiated, specifies a maximum throughput rate of 2.5 billion cubic feet per day. "How can we get around that?"

State Resource Commissioner Pat Pourchot responded that the State has asked for advice on the treaty from its experts in Washington, D.C. He said the amount of gas to be moved isn't actually specified in the treaty, and that 2.5 billion cubic feet/day is used only as a guideline. There isn't anything in the treaty that precludes a larger amount. Pourchot also noted that the original Prudhoe Bay oil reserves had indicated, in the 1970s, that the trans-Alaska oil pipeline might be a "20-year project. We've obviously moved many years beyond that," in terms of additional oil reserves and the life of the pipeline. The same thing is likely to happen with natural gas.

Heyworth replied that present revenue Commissioner Wil Condon had written, in 1982 (when Condon was a state attorney) that the U.S.-Canada treaty is very limiting.

Dan Chay observed that if 4 billion cubic feet per day were shipped in a pipeline along the highway and that if Southcentral Alaska required only 200 million cubic feet of gas per day, if the perspective of the Council is to look at this issue over several generations and assuming that gas will be worth a lot more in the future, then a pipeline through Alaska even at lower rates of throughput might be a service to Alaskans.

Council member Bob Penney made the remark that, "we don't own all of the gas. We only have rights to our one-eighth royalty share."

Chay responded that the State still has some negotiating room in powers it has to set the rate at which gas production takes place.

Carl Marrs observed that whether gas is worth more or less in the future is also a factor of technological change, which is unpredictable. There is also a lot of gas in other places, like Indonesia. In a broader context Alaska is a small piece of the worldwide gas business. Some geologists also say the western U.S. sedimentary basins are on the verge of decline. While LNG is expensive it may be more competitive in the future.

Tom Maloney, an Anchorage resident, told the Council that the company he worked for, Veco Alaska, Inc., started in Kenai in 1968. He himself came up to work on TAPS construction and as soon as the job was over, he went back to the lower 48. What's different between the gas project and TAPS is that in the four major contract packages let so far, all four have heavy participation by Alaskans companies. Veco is in two of the packages; Natchiq is in the gas treatment plant and "B to C" package. It's important that Alaskan companies are involved in this front-end engineering because in a major project like this about 70 percent of expenditures are in engineering and procurement. This year Veco will have 25 engineering intern students, 80 percent of them Alaska Native. Without projects like this, we can't keep high-tech engineering jobs like this in the state. We need to have good jobs to bring back Alaska kids who go outside for their education.

Joe Arness, a Kenai resident and a third generation Alaskan, recalled the bumper stickers after TAPS construction, "God Give Us Another Boom, We Won't Mess It Up This Time." Arness told the Council that a gas project won't be like the TAPS project. But his concern is that the governor's favored proposal of a gasline to the U.S. heartland (via the Alaska Highway) will be such a source of cheap energy for continental U.S. that it could make it politically impossible to peel off gas supply to benefit Alaskans. "I suggest a 48-inch pipeline to Southcentral Alaska, and then a spur line down through Canada."

Alaska Highway Natural Gas Policy Council

AGENDA

May 24, 2001, 12:30 p.m. to 9:00 p.m.
Egan Convention Center, Anchorage

Subcommittee Work Sessions

I. Optional subcommittee meetings *(schedule to be determined by each individual committee chair)*

Council Meeting

I. Call to order

II. Council business meeting

III. Presentation from Cuba Wadlington, President, Williams Pipelines

IV. Presentation from Ed Small, Cambridge Energy Research Associates

Dinner break

Public Hearing

I. Opening remarks

II. Opening remarks from Governor Tony Knowles

III. Presentation from DNR Commissioner Pat Pourchot

IV. Presentation from Ken Thompson on "the Hub" concept

V. Public testimony

Alaska Highway Natural Gas Policy Council

Anchorage Meeting and Public Hearing Summary
May 24, 2001, Egan Convention Center

Cuba Wadlington, Jr., Senior Vice President of the Williams Companies and president of Williams Pipelines, a major U.S. gas pipeline company, gave a presentation on his company's interest in the Alaska gas projects. Williams markets fuel in Alaska and operates a refinery in Fairbanks. Wadlington said Williams is interested in being involved in an Alaska gas project and has initiated a study on possible petrochemical manufacturing in Alaska using gas as a feedstock.

The Council also heard a presentation on North American gas supply and demand by Ed Small of Cambridge Energy Research Associates (CERA).

Small told the Council that CERA does not subscribe to the "30 tcf (trillion cubic feet)" world. We do not see any scenario, not even to 2015, where U.S. domestic demand is likely to reach 30 tcf per year. *(Note: Small is referring to some forecasts calling for U.S. domestic demand to grow from 21 tcf/year (present) to 30 tcf/year by 2010. CERA thinks this is unrealistic.)*

Domestic markets have gone through two stages in recent years, the first being where markets followed what CERA calls a "gas-favored" scenario, where supply and demand progressed gradually in step with each other. We have now shifted to a "realignment" scenario, where gas supply has fallen short of demand. This is a stage we are still in. This could be followed by a scenario we call "aftershock," which could see a recession and slower growth.

Western Canada was one area that faltered last year in meeting its expected growth of gas supply. We were flat last year in terms of growth. Much of this was due to the fact that most drilling was for shallow gas, prompted by low oil prices. We've now seen a tremendous increase in drilling, and we're seeing a supply response. We now expect 16 bcf per day production from the region growing to 19 bcf per day by 2010.

The Scotian Shelf offshore project off Nova Scotia in eastern Canada is an area where there will be increased supply. This project is now producing 4 million cubic feet (mmcf) per day, and we expect this to grow to 3 bcf/day by 2015.

Liquefied natural gas (LNG) is another source of new gas supply to domestic U.S. markets. There are now 4 LNG regasification facilities in the U.S., two of them operating and a third which is just restarting operations. We expect all four of these to be operating and to grow to 3 bcf per day by 2010. They will actually be capable of 4 bcf/day but for maintenance and other reasons actual supply will most likely average 3 bcf/day.

There will also be other new supplies possible from western Canada and from the Rocky Mountains.

Even with these new supply sources, there is an opportunity, a "window" for Arctic gas, which would appear at the earliest in early 2008. This could grow to 4 to 4.5 bcf/day by 2015.

However in the last 6 months, 6 to 7 new LNG projects have been announced to serve the U.S. market. Two of these are in Baja California, which would serve California. We believe LNG projects are now feasible at $3 per mcf, so this sets a benchmark for Arctic gas. Not all of these LNG projects will be built, of course, but how many are built will be influenced by how quickly decisions are made on Arctic gas (i.e. earlier decisions will cause developers of some LNG projects not to proceed).

Under different scenarios we foresee, if there is a recession and slower U.S. market growth, it is unlikely that there will be both full-blown Alaska and Mackenzie Delta gas projects. We would expect to see the Mackenzie Delta project come first, followed shortly by an Alaskan project, probably in 2012.

The risks include gas prices. Sustained prices in the $3 range is probably the break-even point for Arctic gas, and this is the same for new LNG projects. There have been tremendous technological gains, and cost reductions, in LNG in recent years. There are other stranded gas LNG projects in the world that will be done before an Alaska LNG project, however. In this same price range, Arctic gas projects would be feasible, in the $2.50 to $3/mcf range.

Another new challenge, however, will come from clean coal projects. These can now be done in the low $3/mcf range. There are now 14,000 megawatts of new clean coal projects being proposed.

Another factor influencing the market is demand reduction due to high prices. High gas prices last year resulted in some 5.5 bcf/day of demand switching to other fuel sources. About half of this has come back as prices have softened, but we see 3 bcf/day having switched to fuel oil and remaining with that fuel.

There are political questions that affect the Alaska gas project. Two thirds of the pipeline will be through Canada. Recent legislation passed by the Alaska State Legislature (a bill prohibiting a lease of state lands for a "northern" pipeline right-of-way) has had negative effects in Canada. Previously the Canadian federal government had (and still does have, officially) a policy of neutrality as to a "northern" or "southern" route. The government would allow economics to dictate the route.

However, if the State of Alaska says "no" to one route option, this injects a political element. This sets the stage for negotiations "as to who will pay" if a southern route is seen to disadvantage Canadian gas development.

It must be recalled that the Canadian federal government agreed to the original ANGTS treaty on the condition that there be a linkage to Canadian gas development, in the form of a commitment to a Dempster Highway "lateral" pipeline to the Mackenzie Delta. The Dempster lateral is not now a viable option because previously unresolved land claims had blocked the more economically-attractive Mackenzie Valley route. Now those claims are resolved, and a pipeline from the delta would be built along the Mackenzie Valley. However, there is now a possibility that the Canadian government will seek a "linkage" between the Alaska North Slope and Mackenzie Delta projects, as it did in the 1970s. In any event, "we don't see a commitment feasible (by the government) until next year."

Another consequence of last year's high gas prices is that power plants are now shifting from short-term to long-term supply contracts for gas. This is seen as a positive development for Arctic gas (because long-term contracts will help those projects).

Another important question to be dealt with is disposition of natural gas liquids (NGLs). Both North Slope and Mackenzie Delta gas contain NGLs which will have to be removed and sold before the gas is ultimately sold to natural gas utilities. NGLs are usually considered the ethane, propane and butane portions of the gas stream (methane, the primary component, is what is mainly used by utilities). One option is for a plant in Alaska to strip out the NGLs, with only methane transported to the lower 48. The NGLs will then have to be marketed in Alaska. A second option is to build an NGL extraction plant in Alberta, where there is an existing petrochemical industry that could buy NGLs. A third option is to move the NGLs all the way to the lower 48, with a liquid extraction plant built there. New, high-pressure (dense phase) pipelines are now capable of carrying the NGLs along with the methane.

If NGLs are shipped along with methane in the pipeline, the energy content and value of the throughput is increased. If NGLs are extracted in Alaska, so that only methane is shipped, the energy content and value of the throughput will be reduced. "This would have the effect of increasing the hurdle rate (minimum rate of return for investment) of the project, and I'm not sure we want that," Small said.

The new Alliance Pipeline to Chicago is a high-pressure pipeline carrying NGLs from western Canada to Chicago, but the liquids business in Chicago has not been profitable, Small said. The demand for NGLs in the Chicago area has been less than estimated and the plant has been losing money. Were it not for the high prices for the methane (the natural gas) the Alliance project would be losing money, he said.

In summary, CERA sees natural gas prices of $3.50 to $3.75 to 2005. Beyond that it is more difficult to predict. Arctic gas will not be entering the market until 2008, and even at the rates expected, of 2 to 2.5 bcf/day, it will have somewhat of a depressing effect on prices when it enters the market.

Small said he has seen estimates of $6 billion to $8 billion needed to build the pipeline from Alaska to Alberta. Gas will then need to be moved another 1,400 miles to U.S. west coast markets or 2,400 miles to the Chicago area. CERA estimates there is about 2 bcf/day capacity available, with expansions, in the existing Alberta-U.S. infrastructure. The question will be who gets it, the Canadian or the North Slope producers?

Co-chair Frank Brown asked for more information about sentiment in Canada.

Small said the Canadian government's concerns will be on commercialization of gas in the Mackenzie Delta and Mackenzie Valley. It is believed that the delta has 9 tcf of proven gas reserves and growth potential to 45 tcf in the region. This is enough gas to justify a stand-alone pipeline. Under certain circumstances the Alaska pipeline could preclude development of a pipeline from the Mackenzie Delta, possibly until 2015. This will be the Canadian government's major concern, which has been heightened by the legislation passed by the Alaska Legislature.

Council member Brian Davies asked Small to explain again the possible sequencing of Alaska and Canadian gas development.

Small said the most likely timing for Alaska gas to enter the market is 2008, followed by the Mackenzie Delta gas in 2009. Alaska would enter the market at 2 bcf/day, increasing in stages to 2.5 and 3 bcf daily. Mackenzie Delta gas would likely begin at 1 bcf/day increasing to 1.5 bcf/day.

However, there is a scenario in which Mackenzie delta gas could come first. That is if a recession hits the U.S. and demand growth slackens. In that case it will be difficult to raise the large amounts of investment needed for the larger Alaska project. Thus, Mackenzie gas could enter the market first in 2008 or 2009 at about 1 to 1.5 bcf daily, followed by Alaska gas in two to three years, or 2011.

There is also a scenario, which seems unlikely at this point, which would see a larger response than is now estimated from other gas supply sources to the U.S. market. Under this scenario there could be no Arctic gas flowing to market until about 2011. Alaska gas would enter the market at that time, followed by Mackenzie gas a year or two later.

Several Council members asked for clarification of estimates of tariffs on one of the charts in the CERA presentation.

Small explained that the estimate for an Alaska Highway gas pipeline under the ANGTS published estimates were a range of $1.80 to $2.20 per mcf to the U.S. market. Of this, about 85 cents is for the Alberta to U.S. portion. "This is why a gas price of $2.50 per mcf (in the lower 48) barely cuts it, while $3 will make it viable."

The public hearing portion of the meeting began. Gov. Knowles and Anchorage Mayor George Wuerch gave some opening remarks.

State Department of Natural Resources Commissioner Pat Pourchot gave the Administration's presentation on the natural gas pipeline, potential employment, the future demand for Alaska gas and possible in-state uses for energy or feedstock for industrial development.

The Council heard a presentation from Ken Thompson, a Council member, on his concept of a gas trading "hub" in Alaska and the importance of having agreements in place for access to gas in Alaska before a gas pipeline begins construction. Curtis Thayer, representing the producers' group working on the gas project, presented an overview of the companies' study project, including information on contracts recently awarded.

Larry Crawford, president of Anchorage Economic Development Corp., introduced AEDC staff economist Jeff Pokorny to present a summary of the Cook Inlet gas supply situation. AEDC undertook the study because there were a lot of misunderstandings about regional gas supplies. AEDC worked closely with Chugach Electric Assoc. and Enstar Natural Gas. "We believe it is the most accurate assessment to date of the situation."

Pokorny told the Council that gas production began in Cook Inlet in 1959 and that by 1975 about 8.5 tcf had been found. About 215 billion cubic feet per year is used in the region, approximately two-thirds for industrial uses and one third for use by utilities, in electrical generation and residential and commercial space heating.

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Reserve-to-production ratios in the lower 48 are fairly consistent with about 8 to 10 years of supply because the reserve base has been replenished with supply additions. In Cook Inlet the reserve base has been declining because there have been no significant reserve additions in recent years.

The most commonly-accepted estimates of conventional gas yet to be discovered in the inlet range between 1 and 2 tcf, although there are some estimates of 3 tcf. There are also possibilities for conventional gas supply additions in the Matanuska-Susitna area (north of Anchorage) and from gas from shallow coal beds. Estimates are that coal-bed methane resources could be about 8 tcf. U.S. government geologists have estimated a total resource of 250 tcf in coals in the Cook Inlet basin (much of this is deep, however, and unlikely to be commercially produced). The study also cited possibilities that gas could be imported as LNG (the LNG plant in Kenai could be converted from liquefaction to regasification) for a price in the range of $2.50 to $3 per mcf, which is about the price LNG from Asia is being considered for projects discussed for western Mexico.

The study cited options for extending current Cook Inlet region gas supplies. If gas sales to the Nikiski LNG and fertilizer plants were terminated, gas supplies would be extended 6 years. If supplies to only the LNG plant were terminated, supplies would be extended 3 years. The study also noted that as gas prices in Cook Inlet increase, both the LNG and the fertilizer plants could be at risk.

Other findings were that the LNG plant at Nikiski could clearly be at risk by 2009 because the export license is up for renewal at that time (the federal government will not renew the license unless gas is surplus to local needs).

In summary, gas supply in the Cook Inlet region is still better off than in the lower 48, in that there is still a 13-year supply in Cook Inlet, while the lower 48 has an 8-year supply.

In response to questions from the Council, Pokorny related that problems in daily deliverability of gas (at peak times, i.e. during cold weather) could begin as early as 2004. Discovery of 1 additional tcf of gas would extend the peak-time deliverability to 2007. Discovery of 2 tcf of gas would extend it a little further.

Carl Marrs asked at what price coal-bed methane might be economic.

Pokorny answered that there was no clear answer to this. It could be in the range of $3 to $4 per mcf.

Council member Brian Davies observed that coal-bed methane is economic in the lower 48 at today's prices. Coal-bed methane technologies are very specific to the sites where they are applied, and in Alaska the technologies for our particular geologic environment have yet to be developed. Current prices in Cook Inlet do not support local coal-bed methane development but as prices go up it is certainly a possibility.

Council member Jack Roderick asked if AEDC was aware of any studies underway for mine-mouth coal power plants in the region.

Pokorny answered he was unaware of any studies. *(Note: Owners of the Beluga coal fields near Anchorage are now considering possibilities of mine-mouth power generation, as well as gasification, from their resource.)*

Council member Ken Thompson observed that studies several years ago by ARCO Alaska Inc. indicated that, in the long term, gas from the North Slope could be delivered to the Cook Inlet area for less than new conventional supplies could be developed within the region.

Gene Bjornstat, general manager of Chugach Electric Assoc., told the Council that Chugach generates 83 percent of its electricity from natural gas and 17 percent from hydro. There is also coal-fired generating capacity in plants at Healy, supplying Golden Valley Electric Assoc. Chugach has been generating electricity at its plant in the Beluga gas field since 1965. Gas from Beluga was purchased for 15 cents per mcf when the plant first went into operation.

Bjornstat told the Council that Chugach appreciates its consideration of the regional supply problem and believes that decisions made sooner are better than later on this question. Ken Thompson's suggestions of a gas hub and gas takeoff contractual arrangements are very appealing. Timely recommendations and decisions on those will help Chugach in its planning.

Steve Cleary, speaking on behalf of the Alaska Public Interest Research Group, said his members' concerns were those of consumers and utilities in the region. "In the next decade our members will need a reliable source of gas, and we think it must be North Slope gas." Options like burning coal (for local fuel) are not very appealing, and as for importing LNG, if we are concerned about dependence on foreign markets for sales of oil we should be equally concerned about dependence on foreign sources of gas supply.

Alaska Public Interest Research Group would like to see the discussion of supply and use broadened. Cleary said he is intrigued by the hub concept and the use of royalty gas in-kind. He said the Alaska Public Interest Research Group has four criteria to recommend to the Council for consideration: one, that gas be used to benefit Alaskans first; two, that the State profit from gas production (through royalties and taxes); three, that State controls are in place for local access to gas; four, that there is an option for deliverability of gas to tidewater.

Cleary asked that the Council consider a question, that if there is only a pipeline to the lower 48 and that if markets there dropped, the State would lose money (from royalty and tax) but the producers (if they are also owners of the pipeline) would continue to make money through their equity ownership of the pipeline.

Tony Izzo, president and CEO of Enstar Natural Gas, told the Council that he had not planned to speak but felt compelled after hearing the presentations. Enstar serves approximately 50 percent of the state's population and has done so for 40-plus years. "We have one of the best gas utilities in the country, with new high-tech systems, 400 miles of pipelines and 2,400 miles of distribution lines. We are ready to be of service."

We believe Ken Thompson is right on the mark. We endorse the idea of a hub in Fairbanks. Enstar has contracts pending to meet our supply needs to 2006, and we have some contracts that will fill part of our needs to 2017. But we have long-term concerns, beyond that.
"I did some quick calculations, and at our present rate of consumption the 35 tcf of known gas reserves on the North Slope are sufficient to meet the needs of Southcentral Alaska for 175 years. If only the utility needs are considered, which is about one-third of demand, the known North Slope gas

reserves are sufficient for 580 years." In making decisions on use of North Slope gas, "we've got to make sure we take care of ourselves."

Council member Carl Marrs asked at what cost an additional 1 to 2 tcf in Cook Inlet could be made available?

Izzo replied that there were no clear estimates, "but in my opinion the cost will be substantially higher" to acquire an additional 1 to 2 tcf of gas in Cook Inlet. Current gas prices in the region are about $2 per mcf, and the most recent contracts are in the $2.75 per mcf range. He also said Enstar is very interested in a spur pipeline to either Fairbanks or Delta. "We are very interested in securing additional long-term gas supply for Southcentral Alaska."

Scott Heyworth, speaking for his company "Our Gas, Our Future" told the Council that he is aware of 6 LNG projects Phillips is initiating in Asia, one project BP is involved in to import gas to Bolivia, and that LNG from Asia is now being considered for California, "which is the natural market for gas from Alaska." With the shift of control in the U.S. Senate, "ANWR is dead on arrival, and the support the governor has counted on for the Alaska Highway gas pipeline is in trouble. But we can do our own all-Alaska gas pipeline by ourselves" (i.e. no congressional approvals are needed).

Heyworth noted that costs of $10 billion are currently estimated to build the "A to B" pipeline segment from Alaska to Alberta, another $3 billion to build pipelines to lower 48 markets and another $2 billion to build a liquid extraction plant somewhere. This totals $17 billion in 2001 dollars (i.e. an investment sufficient for a large-diamater pipeline across Alaska and an LNG plant in southern Alaska). What makes more sense for Alaska? A pipeline to Chicago, or to Valdez? I know Alaskans don't support an Alaska Highway route. An all-Alaska route with an LNG project is in the best interest of Alaska.

Council member Ken Thompson observed that commodity markets always cycle up and down, and asked Heyworth that if the Asia markets are able to absorb 14 millions tons of LNG yearly from Alaska (the volume produced by a large-scale LNG project), what's wrong with starting smaller at a rate the Asia market will absorb, such as 1 to 2 million tons per year, and then ramping up?

Heyworth replied that he favored the "Y" concept (a pipeline branching off from a large-diameter main line) but that the pipeline should be built to Southcentral Alaska first, and then to the lower 48 when the inevitable litigation over the Alaska Natural Gas Transmission System laws and treaty are finally resolved.

Mike Macy, responding to Ken Thompson's question, observed that it's also a question of economies of scale. A large LNG project will be able to get into the Asia market at a more competitive price. Macy complained that Governor Knowles had made his decision to favor an Alaska Highway route for a gas pipeline without consideration of all alternatives. The governor has never listened to a presentation on a liquefied natural gas export project being proposed by Yukon Pacific Corp., for example. Macy also urged the Council not be used as a "shield" by the governor, to help justify his decision in favor of the highway route.

Council co-chair Frank Brown observed that Jeff Lowenfels, president of Yukon Pacific Corp., made a presentation on his project at an April meeting of the Council in Anchorage.

Council members Carl Marrs and Charlie Cole told Macy they do not consider themselves, being members of the Council, as "shields" for the governor. "I'm here to learn," Marrs said, "The governor is waiting for answers from us." Cole told Macy he had listened carefully to Lowenfels presentation of the LNG option and thought it excellent. "What we do here is not in opposition" to the proposal, he said.

Council member Ken Thompson said he favors LNG from Alaska but that it might not happen on this market cycle. "But would you favor a hub, with the first project to plug into the hub being a pipeline to the lower 48? A hub doesn't say 'no' (to LNG,) it says 'yes.' From 1998 to 2000 I marketed LNG in Asia," and it is ironic that Alaska represents a large source of gas supply to Asia but the very size (and capital cost) of the project needed is a major obstacle, relative to competitive supply sources. "Fourteen million tons per year of LNG is tough to sell in a market of 60 to 70 million tons per year. But I do believe there's room for 1 to 2 million tons. I wonder if we need a paradigm shift? Maybe a smaller project is better?"

Macy replied that there are reasons why North Slope producers don't want LNG from Alaska going to Asia. It is because there are finite terms on leases and concessions the producing companies have in Australia and Indonesia. "They're putting that gas in California and Japan. Those are our markets. If we could sell 9 million tons/year to Asia and 5 million tons/year to California, we've got our large-scale LNG project."

Tom Marshall, a retired state geologist, told the Council that 30 years ago Natural Resources Commissioner Phil Holdsworth sent him to Juneau to explain to the state Legislature the implications of the natural gas found associated with crude oil in the Prudhoe Bay oil discovery, which was announced a short time earlier.

Marshall explained at the time that the best near-term use of the gas would be to maintain pressure in the reservoir to support oil production. As the years passed this pressure maintenance, along with injection of water and misciple injectant (a fluid made from natural gas liquids, used in enhanced oil recovery) has resulted in $100 billion in the value of additional oil produced. The availability of gas for enhanced oil recovery has also aided in production of oil from the Kuparuk River and other oil fields on the North Slope, and will play an important role in production of viscous (heavy) oil from the very large West Sak and Ugnu formations.

"What concerns me (about the discussions of natural gas being commercialized and moved off the slope) is that I want to see as much of the gas as possible used where people live. Seventy five percent of Alaskans live along the railbelt." Our gas is in the railbelt, "it will take a little ingenuity to figure out how coastal LNG tankers can move gas to other coastal areas."

Another concern is that we hear estimates of 35 tcf of reserves on the slope. "If we produce at 4 billion cubic feet per day, this is a 25 year supply. If we use a more realistic figure of 26 tcf (actually available for commercial sale after uses on the North Slope) and we subtract the 14 percent of this gas that is carbon dioxide (which will be removed from the gas before it is shipped) and natural gas liquids, we have a project with known reserves sufficient for 17.8 years. However, a large project like this must be able to operate for at least 30 years to justify the investment. "Therefore, whoever is building this project is depending on undiscovered resources. As a geologist, I will tell you that is pretty risky."

"It doesn't make any difference to me whether we deliver North Slope gas to Chicago or Japan, but I do want to see gas made available in Alaska. Gas can be used for so many things. In the Fraser River valley of British Columbia, local gas is used to heat greenhouses to make tomatoes for export to California. Gas is the preferred fuel for fuel cells. The options for using gas in Alaska will create many opportunities for our young people."

"The North Slope petroleum province is so much beyond anything I have seen in the south 48 states, but the concern I have is that BP, Exxon and the other producers will figure out a project that is just large enough" for an Alaska Highway route. "The North Slope could give Alaska a stable supply of gas for 100 years. Let's serve Alaska first and if gas reserves turn out to be very large, then we can send it Outside. What's wrong with creating economic incentives for using the gas in Alaska? It's okay to give Alaskans an economic advantage."

Council member Carl Marrs observed that "all of us would like to find ways to enhance the value of gas used here, but on the economic side we must assure whoever is doing the project will get a return."

Marshall replied that the governor and his advisors are well motivated to pursue an Alaska Highway route. Economics are important, and markets and prices do change. The project may not look so good at $3 per mcf (prices in the lower 48). The gas pipeline is an extremely complex problem. It won't be solved with a snap of the finger.

Jerry McCutcheon, an Anchorage resident, told the Council that there were documents held at one time by the Alaska Oil and Gas Conservation Commission related to estimates of Prudhoe Bay oil and gas in-place resource estimates that have disappeared. He encouraged the Council to try and locate these documents. McCutcheon said there could be more oil produced from Prudhoe Bay and using gas to maintain the reservoir pressure is important.

Harold Heinze, an Anchorage resident, told the Council he is a former ARCO Alaska Inc. manager and a former state Commissioner of Natural Resources. When he was at DNR he worked actively to market Alaska's gas. "I came here in 1969 and I lived through the TAPS years. I think we can avoid some of the mistakes made during TAPS. Clearly, the governor should be congratulated in forming this Council and getting an important dialogue started." On projects like this, "I would like to see us consider things like an Alaska-Yukon 'free trade zone.' There's no reason that the project changes at the border." The Alaska and Yukon people both have priorities in maximizing jobs. We should all have opportunities to work up and down the pipeline. "The President has made it clear that he considers having good relations with Canada very important." Heinze also recommended that local citizen advisory groups be formed as part of the pipeline planning effort up-front. This wasn't done during TAPS, but there were tremendous impacts on small communities. On local-hire, "we need a more creative approach. The pipeline is being built across our (state) land. There has got to be some way we can legally ensure local people" are given priority in hiring. "We should also be flexible when we discuss the need for gas. Sometimes it's smarter to move electricity than gas. We could think of the Delta-Glenallen-Fairbanks areas as the electricity belt," where it could be more economic for regional power plants, fueled by gas, to produce energy than to build gas pipelines.

Heinze also urged the Council to move these discussions along. "I've lived here for 30 years and I've seen us at this point before, and there is value in taking action." He also said he is concerned that the

Alaska Oil and Gas Conservation Commission is "behind the curve." The current Prudhoe Bay field rules do not permit commercial gas sales, and AOGCC hearings will have to be held before they are allowed. "I know that the questions will be answered, but the AOGCC needs to get on it." Heinze also endorsed the concept of a State gas pipeline office, where everything having to do with gas pipeline decisions are in one place. "It's unfortunate the Legislature didn't provide for this. We've got to find the money and get on with it."

DNR Commissioner Pourchot mentioned that at the very end of the session the Legislature did provide some money for startup of a state gas pipeline office.

Heinze recommended the Council obtain copies of a 1983 publication by the University of Alaska's Institute of Social and Economic Research titled, "The Struggle for an Alaska Gas Pipeline," as excellent background reading. "The State of Alaska needs to be looking at its own best interests, but also why things are being done the way they are. Some issues are not as obvious as they might seem. My instincts tell me that Alaska hire is a bigger issue than many people think."

Council member Jack Roderick asked Heinze his opinions on the State taking an equity position in the gas pipeline.

Heinze replied, "I hate to see the State put in hundreds of millions of dollars to get information it could get through regulatory processes. I have a dim view of this because the State does not have a management vehicle to make risk investments."

Council member Ken Thompson observed that if the State doesn't have an equity interest, it pays a tariff (to private equity owners) for transport of royalty gas that includes federal taxes. With an equity share, "we can move our own gas at lower cost" (because the state would pay no federal tax) and pass these advantages on to in-state gas users.

Heinze replied that the Department of Revenue will be doing a study of possible state equity participation. "But I wouldn't leap too quickly."

Council member Charlie Cole observed that during the TAPS tariff negotiations in 1985 the State was able to take the position that as an owner of oil reserves it favored low tariffs, which also enhanced exploration. If the State had an equity interest, its interests in low tariffs might change.

Heinze commented that there are also issues around the "trajectory" of the tariff. In the 1985 TAPS tariff proceeding the State chose to allow high tariffs in the early years in order to allow low tariffs in the later years of the pipeline. "Without that (tariff structure) our royalty oil would be worth less. We may face policy choices like that with a gas pipeline, too."

Paul Simons, an Anchorage resident and a retired chemist, urged the Council to consider the possibility that gasification plants can be built on coal fields, with many products made from the gas. This is being done now by Sasol in South Africa, and a large U.S. coal gasification plant is operating in North Dakota.

Alaska Highway Natural Gas Policy Council

AGENDA

June 14, 2001, 5:00 p.m. to 8:00 p.m.
Tok School

I. Community Reception sponsored by Doyon, Ltd.

II. Meeting call to order/Welcoming remarks

III. Presentation from DNR Commissioner Pat Pourchot

IV. Public Testimony

Alaska Highway Natural Gas Policy Council

Tok Public Hearing Summary
June 14, 2001, Tok School

Council members attending included Co-chair Frank Brown, Mike Navarre, Rosemarie Maher, Rhonda Boyles and Charlie Cole. State Natural Resources Commissioner Pat Pourchot and Deputy DOTPF Commissioner Kurt Parkan also attended.

Co-chair Brown, who presided at the meeting, suggested a more informal question-and-answer session rather than the traditional public hearing format for a meeting.

(Note: Because the meeting was informal, with people asking questions and making comments from the audience, the editors were unable to get names of people speaking.)

Brown explained the Council's purpose: to study options for maximizing benefits of the natural gas pipeline to the state and to make recommendations. The governor has also formed a gas cabinet within the Administration, headed by Commissioner Pourchot.

Pourchot gave the Administration's presentation on the gas project.

A question from the audience asked how Alaska was coordinating with Canada on the gas pipeline.

Pourchot responded that Canada's federal government has just set up its mechanism to work on the project. The Prime Minister has set up a "gas cabinet" just as Alaska has done, with seven to eight departments involved. "They are clearly up to speed, although they are, officially at least, still neutral on the route question," the Commissioner said. Canada's parliamentary system allows the government to form unified positions because the party controlling parliament forms the government. The federal government is more in control of events in the territories, such as Yukon and Northwest Territories. Once the pipeline crosses into British Columbia and Alberta the provincial governments will exercise considerable influence.

An audience member asked about the preference by some Canadians for a northern route, and asked about the status.

Pourchot answered that Canada's federal government has taken the position that it doesn't want its northern gas stranded. The government doesn't want the movement of Alaska's gas to strand Mackenzie Delta gas.

The government also shows sensitivity to the concerns of aboriginal groups. The situation on aboriginal land claims in Northwest Territories has now changed, however. Most claims there have been settled, and the interests of aboriginal groups are now aligned with development of a pipeline along the Mackenzie River Valley. However, land claims in Yukon and northwest British Columbia are not settled, and they will have to be settled before an Alaska Highway gasline is built. There are discussions on this under way now, Pourchot said, although the status of talks is unknown.

A question was raised on status of a gas pipeline to Valdez. Has it been eliminated?

Pourchot replied that a pipeline to Valdez would require use of liquefied natural gas technology and reliance on markets in Asia. "Our best information is that the Asia market does not now support a stand-alone pipeline to Valdez. However, the Alaska Highway route (to the lower 48) does not rule out a spur pipeline to an LNG plant in the future." Natural gas prices in the lower 48 are very strong, about $4 per million cubic feet (mcf) now. Although the price has slipped (it was $5/mcf) it is still higher than the $2/mcf two years ago.

A question was raised about the timeline for a gas pipeline.

Pourchot responded that the producers will make this decision, but the best information the State has is that a target date of 2007 is under discussion.

A member of the audience asked about the impacts of gas pipeline construction. Since the technology is simpler than the trans-Alaska oil pipeline, wouldn't the impact be less?

Pourchot replied that the workforce requirements for the gas pipeline would be far less than TAPS, partly because the infrastructure is available to support construction. The gas pipeline technology is newer, but the entire project is simpler. Since the pipeline will be buried in total there isn't the need for the extensive design and engineering work needed for above-ground sections as for the TAPS line, or the vertical support members. There will still be two to three construction seasons involved. There will be thousands of people employed, but considerably less than TAPS.

One member of the audience asked what benefits the project would bring for small communities. Tok has no incorporated regional government and no opportunity to use the pipeline as a tax base. To use the gas, a gas utility will have to be established. The compressor plants for the pipeline present opportunities for use of waste heat, but the location of the compressor stations is not yet known. "I support the highway route, but what is the long-term benefit?"

Co-chair Frank Brown replied that the option to form a local government lies with the community. Presence of a pipeline doesn't automatically mean a government will form. The TAPS oil pipeline was built through the Glennallen area almost 25 years ago but there is still no borough government in the area. It is true that it isn't yet known where compressor stations will be located, although it is believed that several will be in the Tanana River valley. In the old Alaska Natural Gas Transportation System proposal there were 12 compressor stations planned in Alaska. The new plan will probably involve fewer, and they will be more automated with fewer people operating them.

A question was asked about local hire, meaning hiring from the local community.

Council member Mike Navarre replied that there is a subcommittee working on this. The Departments of Labor and Law are providing assistance to determine what can be done. Also, the governor is taking the issue up with the producers, to see what they are doing, Navarre said.

A question was asked whether it would be possible to ease regulations so that Native people could work on the pipeline on both sides of the border. Several people from the Dot Lake community attended a First Nations conference in Whitehorse in which Foothills Pipe Lines made presentations

on construction techniques. It became apparent that pipeline crews using modern technologies will move very fast, building several miles per day. Construction crews will be in the Dot Lake area for just a few days, which would seem to limit opportunities for training and employment in construction.

Council member Charlie Cole said that Harold Heinze, a former state Natural Resources Commissioner and ARCO Alaska manager, had suggested to the Council a free "economic zone" from Delta to Whitehorse where people could move back and forth without red tape. "His thought was that it could apply to all labor," Cole said.

A response from the audience was that only local people should be able to take advantage of a free-movement economic zone, not imported labor.

Co-chair Frank Brown said that local people should be able to tap gas from the pipeline. A small local utility will be needed, but this energy will be cheaper than any other form of energy the state has experienced. The cheapest alternative form of energy will probably be twice as expensive. There is also the possibility that gas will provide an energy source for mine development in the vicinity, through a small spur line to the mine.

Also, at points along the pipeline route there may be possibilities for industries that use gas or gas liquids. Propane could become a small industry, for example. These are potentials, Brown explained.

An observation from one person in the audience was that development of industrial infrastructure could change the community's rural character. Even development of a gas utility or incorporation of a regional government could impose "costs" by changing the character of the community.

Co-chair Brown replied that these were options. The community can decide whether or not to take advantage of access to gas.

A question was raised as to whether Fairbanks was considering natural gas plants, and whether the Tok community could buy products (such as propane) in Fairbanks.

Fairbanks North Star Borough Mayor Boyles, a Council member, replied that her community is looking to expand its economic base and hopes to develop new gas-based infrastructure.

A question was asked on who has the final say on a pipeline route.

Commissioner Pourchot said that the producers, or a consortium planning a pipeline, come to the State with a route application. "We look at it and review it." While the general route is selected by the applicants, the specific route is influenced by state and federal agencies, he said.

A comment from the audience was that in 1979 when the Northwest project consortium (the previous Alaska Highway gas group) was considered a strong project, one of former Governor Hammond's first actions was to set up a socio-economic impact committee of local people, so that local people could decide how to handle impacts of construction. How will the Gas Policy Council deal with this kind of question?

Council member Navarre replied that the subcommittee he chairs is working with economists with the Department of Labor and Department of Revenue, seeking funds to do a socio-economic study to use in the Council's final report. Dept. of Labor is also doing some separate, but related studies, and the Legislature may also deal with this issue.

Fairbanks Borough Mayor Boyles said her community is dealing with estimating socio-economic effects already. The University of Alaska's Institute of Social and Economic Research has been asked to help Fairbanks estimate social and economic effects.

A comment from the audience is that Alaskans' experience with promises of cheaper energy has not been promising. When the Anchorage-Fairbanks electric intertie was planned, studies predicted a lowering of electricity costs in the railbelt. This has not materialized. The construction of refineries in the state has not resulted in less expensive gasoline, either.

Council member Charlie Cole replied that he is incensed about the price of motor fuels in the state. His theory is that gasoline and others fuels are priced just slightly under the cost at Cherry Point, Wash., the nearest large out-of-state refinery (meaning that the Alaska price has no connection with the fact that oil is produced and refined here). Cole said he intends to do everything he can to ensure that local prices for natural gas are tied to a netback pricing scheme (the "netback" price on the North Slope, with tariffs added to move gas to Fairbanks, Tok or some other in-state point).

Skepticism was expressed from the person in the audience, who felt Alaska "already has strikes against us" from the past track record. "How are we to believe the gasline will really bring lower costs for gas when the track record has been the opposite?" He urged the Council to be realistic on this issue when talking with the public.

Co-chair Brown replied that the nature of gas is different than crude oil, which must be refined into usable products. The cost of delivering gas to Tok will definitely be cheaper than delivering it to the lower 48.

Commissioner Pourchot added that local prices will still be affected by overall supply and demand. "We will still see prices influenced by some other market. We won't have cheap gas in an isolated market."

A comment, and a question, from the audience was that local electricity prices were 22 cents/kilowatt hour. Would natural gas bring down electricity costs?

Commissioner Pourchot said there was no way of knowing for now. How we get access to gas, such as the State taking its gas in-kind, could make a difference. It would be a local decision to invest in the gas distribution infrastructure. In a small market, with just a few hundred homes, the economics get tougher.

Ken Freeman, staff to the Council, explained that these meetings are for "scoping," to find out what issues are important to Tok. He explained the Council's organization into subcommittees for dealing with specific issues.

Several comments from the audience followed regarding the cost of infrastructure and gas conversion. One audience member pointed out that hydro power is supposed to be cheaper in the long term, but the heavy up-front capital cost creates higher power rates for consumers in the early years. In Alaska this can be as much as six to eight times the cost of alternative forms of energy. The same may be true, to a lesser extent, with gas. There will be higher initial costs until an investor recoups the capital investment, unless there is a subsidy.

The regional manager for Alaska Power and Telephone commented that their studies indicated that it will cost $40,000 to convert one of the utility's diesel generators to gas. Plus, the generator will be "de-rated" by about a third, which means fueled by gas it generates one third less electricity than if fueled by diesel. This means the utility will have to add an engine and generator to compensate for the de-rating and produce the same amount of power. Plus, there will have to be a diesel-powered generating unit on standby. All together, the costs associated with conversion to gas are estimated at $600,000.

Another audience member commented that because of conversion and infrastructure, and other costs, the gasline could wind up imposing more costs than benefits, at least in the short term. "I'd rather just get my dividend," was the comment.

Council member Mike Navarre replied that his community, Kenai, has seen great benefits from natural gas. When his family arrived in Kenai in 1957 there were 323 people and no gas. Over the years, the availability of gas and the industrial development it brought has greatly benefited the community. "If the gasline runs through here there may not seem to be short-term benefits but in the long term these could be substantial. Some of the short-term costs could be offset if a local government is set up, or perhaps there could be temporary State subsidies."

A question was asked about the feasibility of a tap on the pipeline near Tok, and the minimum size to make a tap economic.

Co-chair Brown replied that the minimum size of tap to be feasible isn't yet known.

A question was asked on whether the State is likely to take royalty gas in-kind.

Commissioner Pourchot replied that the majority of the State's royalty oil share is now taken in-kind and sold to Williams Companies, for the Fairbanks refinery. In the past royalty oil was sold to Tesoro and PetroStar. A factor in the design of the pipeline will be whether the State's one-eighth royalty share will be shipped with the producers' gas to the lower 48, or used in the state.

Co-chair Brown added that one of the subcommittees of the Council is looking at how a tap on the pipeline can be contractually provided for before construction.

A comment from the audience was that during planning for the former ANGTS project in the late 1970s, the proposal was to install taps at the beginning because to put them in later would add costs.

Co-chair Brown replied that new technology allows for a "hot tap" procedure where taps can be installed without shutting down a pipeline.

A question was asked whether the Council's pipeline-related work is being coordinated with Rep. Jeanette James' efforts to see a railroad corridor established in the region.

Commissioner Pourchot replied that the Administration doesn't support James' bill (which is still in the Legislature). The bill provides for lands in a right-of-way to be transferred to the Alaska Railroad, which can then sell off corridors for other uses, such as a fiber-optic cable or a pipeline. The Administration believes the State should establish rights-of-way for these other uses, and not make a large land grant to the railroad and let the railroad manage the additional rights-of-way.

A question was raised whether there would be multiple corridors for all of these or a single corridor.

Commissioner Pourchot replied that one of his department's main projects now is looking at land status questions for a pipeline right-of-way. Foothills Pipe Lines has a right-of-way granted by the federal government from the ANGST project and is preparing an application for a State right-of-way. The railroad proposal is for a study, and there is actually no money yet to do the study, either in the U.S. or Canada.

A question was raised whether the Tok community may have to deal with right-of-way corridors several times, for a pipeline, railroad or utility.

Commissioner Pourchot replied the answer is probably yes.

A question was asked about the economic life of the pipeline.

Commissioner Pourchot said the economics many oil and gas projects are designed around are an expected 20 years of life. However, the pipeline itself, with proper maintenance, could last considerably longer. The estimated gas supplied on the slope could support the pipeline for many years beyond 20 years, he said.

A question was asked if there were any other right-of-ways issued.

Commissioner Pourchot replied that Yukon Pacific Corp. has received a conditional State right-of-way for its route (parallel to the TAPS pipeline to Valdez) and that in the 1980s the ANGTS group received a federal right-of-way as well as some permits. An application for a State right-of-way was prepared.

An audience member recalled that 10 years ago when the Air Force was planning its Backscatter radar projects, which would have included some facilities in the Tok area, an excellent job was done in projecting the long-range local job requirements and posting information in the community.

Mike Navarre, a Council member, replied that his subcommittee was assessing skills available in Alaska and the size of the available workforce. "We'll report what kind of jobs are required, but we won't get down to the community level," he said.

Mayor Boyles, a Council member, summarized what she learned at the meeting:

- Local hire is an issue.
- The ability for the local workforce to work across the border is desired.
- There is concerns for energy costs and the benefits the pipeline could provide in lower-cost energy.
- There are concerns about social impacts and changes to a rural way of life.

Co-chair Brown observed, "I felt like this was one of our better meetings. It was more like conversation. I learned a lot."

Alaska Highway Natural Gas Policy Council

AGENDA

July 19, 2001, 12:30 p.m. to 5:30 p.m.
North Slope Borough Assembly Chambers, Barrow

I. Community Reception, sponsored by the North Slope Borough

II. Public Hearing begins

III. Introductory Remarks, Co-Chairs Frank Brown and Jim Sampson

IV. Remarks from Acting Mayor Margaret Opie

V. Welcoming remarks from Governor Tony Knowles

VI. Remarks by Dept. of Natural Resources Commissioner Pat Pourchot

VII. Invited Presenters

A. North Slope Borough

B. Alaska Eskimo Whaling Commission

VIII. Public Testimony

IX. Full Council meeting

Before the meeting, the Council toured the Barrow gas field and local gas utility facilities. The day after the meeting, Council members toured the Alpine Facility and the Prudhoe Bay Central Gas Facility.

Alaska Highway Natural Gas Policy Council

Barrow Public Hearing Summary
August 19, 2001, North Slope Borough Assembly Chambers

Co-chair Frank Brown opened the meeting, noting the presence of both Governor Knowles and Lt. Gov. Ulmer, as well as many members of the full Council. For the audience, in Barrow as well as listening by radio, he described the Council and its purposes.

Governor Knowles made some opening remarks, indicating that people of the North Slope have helped "set the standards" for projects in the Arctic.

Lt. Gov. Ulmer mentioned her appreciation for tours of the Barrow gas field and local gas utility facilities prior to the meeting. "I had wanted to see how you are using a local gas resource, how a community takes advantage of the opportunity presented by gas. We need to learn how you have balanced subsistence with economic development and retained subsistence while also encouraging appropriate development."

Molly Pedersen, president of the North Slope Borough Assembly, was the first person to speak to the Council. She was representing the mayor, who was in London at the International Whaling Commission meeting.

Pedersen said that people of the North Slope have played an active role in oil and gas development over the past 25 years, a partnership in which the role of the Borough and other organizations has been to enhance the protections of development activity. "At times our insistence on environmental safeguards has been a thorn in the side of industry, but the Borough's role has been important to the state. We are actively supporting lobbying for ANWR development, for example, including giving financial support to the effort. Because our agenda is beyond that of income from oil and gas, we are Alaska's most powerful response to the Gwich'in (an Athabascan group who oppose ANWR exploration) and the environmentalists."

"We bring the same partnership to natural gas. We applaud the governor's early commitment to an Alaska Highway route for the gas pipeline because this route would increase the potential for in-state use, the options for public sector involvement in the project. The North Slope Borough has expressed an early interest in public sector involvement through its membership in the Port Authority. The Borough will now await the conclusion of the Gas Policy Council's deliberations, as well as those by the Legislature's committee, chaired by Sen. Torgerson, and the industry's studies. There are a lot of questions to be answered before a plan to develop the natural gas can be put forward."

Pedersen noted that gas is a clean fuel and that its use will reduce pollution. "My biggest concern is that while development of the gas will be good for the nation and the state, the environmental risks of a large project like this are concentrated on our lands."

Charlie Neokok, a member of the Barrow Whaling Captain's Association and representing the Alaska Eskimo Whaling Commission (AEWC), told the Council that "subsistence hunting is at the core of our culture."

"We recognize that oil development has brought the standard of living in our villages up, although it is even today at a minimum standard compared with elsewhere." Most of the benefits of gas development will go to other communities, mainly in the lower 48, "while our communities will bear 100 percent of the environmental risk."

The AEWC realizes that two routes are under consideration for the gas pipeline. The AEWC supports the onshore Alaska Highway route because it provides opportunities for communities to use gas because it will provide more jobs and because it will add more tax base. "It is important to keep the pipeline onshore. We adamantly oppose the northern route because it would take the pipeline directly through the fall whale migration areas where we hunt. These are important feeding areas."

Of particular concern is the potential disturbance of offshore dredging. "There is no telling how long it will take to recover," from the effects of dredging. The ongoing maintenance activity on an offshore pipeline will also have impacts on wildlife. Research has shown that offshore seismic activity has disturbed whales during migration despite the industry's assurances otherwise. Whaling captains are concerned that an offshore pipeline will create a tremendous disturbance, but that industry, "is driven by greed, and will tell us whatever it takes to get what they want. The Arctic is unforgiving. Life here is fragile."

(Note: An extensive discussion among Council members and an industry representative followed Neokok's remarks. We will summarize the main points advanced.)

Curtis Thayer, representing the gas producers' group working on feasibility and cost studies for the gas pipeline project, described the studies underway now, which include the large gas conditioning plant on the North Slope, various sections of pipeline from Alaska to Alberta, Canada and from Alberta to lower 48 markets, and a natural gas liquids extraction plant located somewhere along the route. He described extensive logistics studies underway, of trucking needs and capabilities of ports through which material will be moved.

The heavy-wall pipe required for a high-pressure pipeline presents special challenges. It is so heavy that only one pipe length can be moved on a large truck, compared with several pipe lengths (of thinner wall pipe) moved on a truck during construction of the trans-Alaska oil pipeline in the 1970s. The high-strength types of pipe being considered have never before been rolled into 48-inch pipe diameters, and the only countries with the technical capabilities of doing this are Japan and Korea. It would take two full years of the steel production capacity of those countries to produce the amount of pipe needed.

The northern route is about 200 miles shorter, but there are questions as to whether it can be done. The industry group is now beginning sonar studies of bottom conditions along the route, to see if it is possible.

In the end, the industry has to have an economic project. "At this stage we don't have an economic project," Thayer said. "The analysis underway now is how to get an economic project. We have not completed the analysis for the three companies. It's like we're building a car. We don't know if anyone will buy it."

Governor Knowles commented that the northern route, on paper, appears less expensive, but this still begs the question of how the concerns of North Slope people can be quantified in economic terms. "What is this testimony (from North Slope communities) worth," (in the economic calculation)?

Carl Marrs, a Council member, asked the industry how it responds to the concerns being expressed at this meeting. "It sounds like they've already got it down to costs per mcf (thousand cubic feet of gas) but I haven't been given any information on the (effects of) trenching, and the safety risks."

Bob Penney, a Council member, remarked that the environmental impact statement for the project must take the human element into consideration along with the cost savings of building 200 miles less pipeline. Penney observed that in 1976 and 1977, during previous debates over gas pipeline routes, it also appeared that a northern route would be cheaper. But it wasn't possible to build. Now, if industry concludes that if there can't be a northern route there might not be a gas pipeline at all, "a lot of Alaskans will say fine, let's just leave the gas in the ground."

Charlie Cole, a Council member, questioned whether the industry group can really say the northern route is cheaper before the ocean bottom conditions and engineering problems are really understood.

Ken Thompson, a Council member, commented that he would not trust a net present value calculation of a pipeline route that has, in reality, little chance of securing permits. The petroleum industry in Alaska has realized billions of dollars of benefits, but coming with that is a responsibility to include the community values in its assessments, which are "a bigger part of the equation than net present value."

Richard Glenn, vice president of lands for Arctic Slope Regional Corp. (ASRC), spoke next to the Council, representing ASRC.

ASRC owns about 4 million acres of lands with prospects for gas, he said, and ASRC's mission is to use its resources to better the lives of its shareholders. ASRC must also balance the material benefits of gas development with its responsibility of environmental stewardship and protection of its lands.

The regional corporation owns lands in the Brooks Range foothills with some of the best prospects for gas in the U.S. One of the corporation's concerns is access to the pipeline for gas produced by non-pipeline owners, and whether a pipeline leaving the North Slope will have adequate capacity for future production of gas.

Access to opportunities presented by a pipeline project is also a major concern for ASRC, including jobs and business opportunities for the corporation's oil service subsidiaries. ASRC's companies have proven their competence and have much to contribute to the project. Glenn noted the involvement of Natchiq, Inc., ASRC's subsidiary, in engineering and design work for the large gas conditioning plant and the "B to C" (Alberta to lower 48) pipeline studies. There has been little discussion so far of who will own the pipeline, however. "We seek to be a part of that. ASRC wants to be there," he said.

ASRC joins the North Slope Borough in supporting an overland pipeline, which will also provide access to the significant resource potential of the central North Slope (foothills) region. "We are confident the producers will come to the same conclusion," he said.

Glenn urged the Council to study Barrow as an example of how gas has benefited a small community. Use of diesel fuel presents risks of an interruption of supply, and risks of spills, where natural gas is more reliable and cleaner. He noted there is a significant capital cost for a community to convert from diesel to gas, however.

Following Richard Glenn, there were comments by telephone from several villages on the Slope. From Atqusuk came comments that, "we've been waiting a long time to hook up to gas," and that the producers should build the pipeline overland, but with regard for caribou. "We live off caribou."

Council co-chair Frank Brown commented that all proposals so far for a natural gas pipeline involved burying the pipeline.

From Kaktovik, Fenton Rexford, representing Kaktovik Inupiat Corp. and its 110 shareholders, supported the comments presented by the AEWC and the North Slope Borough. "This summer the ice has been very heavy between our village and Canada. We watch these conditions closely because our relatives are travelling back and forth," to Canada. Ice ridges are very high this summer.

Mayor Gonzalez, of Kaktovik, followed Fenton Rexford and supported his testimony. He said that Kaktovik's city council had passed a resolution supporting an onshore pipeline route and opposing an offshore route, and supporting the concept of participating in the project through the Port Authority.

From Point Hope, Jack Schaefer said the North Slope Borough is experiencing declining revenues from property taxes that is causing hardship in the villages, because of layoffs and lost benefits. He added that ASRC should be a partner in a gas project.

Willie Neokok, mayor of Point Lay and a member of the North Slope Borough Planning Commission, told the Council he also supported the onshore gas pipeline. He concurred with the comments by Jack Schaefer that there is rising unemployment in the villages and that the gas project represents an opportunity for local people to go to work. He also pointed out that repairs and maintenance to an offshore pipeline would cost more and that salt water could have corrosive effects on pipe.

From Nuiqsut, the village nearest the Prudhoe Bay oil fields, Isaac Nukapigak, president of Kuupik Corp., said his corporation supports new development as long as it is done in an environmentally responsible way. If the pipeline is built by the overland route, there will be more contracting opportunities for Alaskan firms, he pointed out.

Ely Nukapigak, also a resident of Nuiqsut, said the community had sent a letter opposing an offshore pipeline. Cross Island, offshore Prudhoe Bay, is an area of particular importance for Nuiqsut in whaling, he added.

From Anaktuvuk, there was cautious support expressed for the overland pipeline, along with the hope that gas availability would lower energy costs in North Slope communities.

From Wainwright, there were comments that gas production could result in some lost oil production from the underground reservoir. The oil producers should be taking a careful look at this. A question was asked about the kinds of technology that would be available to minimize lost oil production and produce the remaining oil from the Prudhoe Bay field.

The mayor of the City of Barrow commented that the best way to protect subsistence on the North Slope is to build the pipeline down the highway. There is no way to really put a value on lost subsistence, he pointed out.

There is a perception that people of the North Slope have realized a lot of monetary benefits from oil production, through taxes, he said. But this is just a minor fraction of the monetary benefits that others have realized from the oil fields. The gas pipeline will add to the tax base of the North Slope, offsetting depreciation of oil production facilities in the existing fields.

He also hoped the rest of the state would appreciate the position of North Slope communities, so that there is no need to continually have to hire lawyers for the communities to get what is rightfully theirs under existing tax laws of the state.

Charlie Cole, a Council member, asked how important the property tax is to the Borough. The gas producers may ask for property tax relief for their project, he pointed out.

The city mayor replied that the property tax is of utmost importance to the Borough. The North Slope Borough is carrying a heavy debt load from general obligation bonds issued to make local improvements. It is important that the Borough be allowed to continue benefiting from property taxes.

Patsy Aamodt, president of the Native Village of Barrow, told the Council her community wishes no offshore exploration for development of natural gas, and "full funding" of State education funds for schools in the region, "without having to fight tooth and nail." The community supports responsible oil and gas development as long as it's not done in the ocean, she said.

Aamodt mentioned that her son is a certified welder now working in the Milne Point field on the North Slope, and she hopes the highway gas pipeline will provide employment opportunities for him and other young people on the North Slope.

Delbert Rexford, a local resident, told the Council he has served on the local city council as well as on a state oil and gas policy advisory council and has been active in the Alaska Municipal League. He supports the overland route because it can be more easily repaired and maintained, he said. The highway route will also bring important benefits to the local communities. North Slope communities are facing economic and social problems, but over the years the State of Alaska has been cutting back on municipal revenue-sharing. The industry has also made great strides in reducing environmental impacts and its "footprint" on land with its new projects, but these advances also reduce the tax base for the North Slope Borough.

Rex Okakok, director of planning for the North Slope Borough, submitted written comments to the Council.

Edna McLean, president of Ilisagvik College, said her institution has looked at the options for North Slope gas and believes all Alaskans should support the highway pipeline route. This route represents the greatest opportunity for jobs with the least disruption of the environment. Ilisagvik has successfully developed training programs in a variety of fields, ranging from heavy equipment operation to computer training. The college also helps students who have not completed high school

to get their GED and to improve english and math skills. Virtually all graduates of Ilisagvik are able to get good jobs upon graduation. Ilisagvik is ready to work with developers of a highway gas pipeline in training, she said.

Ben Nageak, former North Slope Borough mayor, told the Council he opposes offshore development and considers onshore development as the only prudent way to develop oil and gas resources. Nageak said he was proud of his role, when he was mayor, in helping form the Alaska Gasline Port Authority, with the assistance of Jim Sampson, former Fairbanks borough mayor and now co-chair of the Gas Policy Council, and former Valdez Mayor Dave Cobb. The Port Authority could be an important tool for developing and marketing Alaska gas, and Nageak hoped its formation encouraged the producers to begin their own studies of building a gas pipeline.

Marie Adams, vice president of Arctic Slope Native Association for health services, said her association oversees operations of the 35-year-old public health hospital in Barrow. She urged the Council to consider how important subsistence is in the diet and health of Native peoples. Studies being done in the Nome region are showing that subsistence foods can be important in restoring peoples' health who are afflicted with diabetes and heart disease.

Adams expressed concern about effects of construction of an offshore pipeline on beluga whales, which are important as a subsistence resource for communities in the Mackenzie Delta. The beluga whale population in the Beaufort Sea may range far more widely than is thought, and effects on the population may affect villages in Alaska.

Ned Aerie is a subsistence hunter who travels many miles to get food for his family. He is concerned with the movement west of onshore oil and gas activity into the NPR-A because of contaminants and effects of seismic activity on caribou. He opposes offshore activity because the industry has not demonstrated it has adequate plans for cleanup in the difficult ice and wind conditions of the Beaufort Sea. He also opposes an offshore pipeline because there have been no studies of its feasibility or environmental impacts. He expressed concern over high fuel prices on the North Slope and the unfairness of paying prices far higher than paid by consumers thousands of miles away, "when this is where the oil comes from."

Charlie Cole, a Council member, agreed with this. In Fairbanks people pay over $2/gallon for gasoline when it is manufactured in a refinery 10 miles away, from crude oil from the North Slope, he said. He expressed concern that the same thing may happen if a gas pipeline comes near Fairbanks. "We've got to take a stand on this," he said.

Price Brower, director of the North Slope Borough Search and Rescue, said the borough research and rescue services have often been called to assist in support of oil field and trans-Alaska pipeline operations. The unit is available to assist with gas pipeline-related work, he said.

Rex Peter, a stockholder in ASRC, urged the Council to emphasize that the highway route is best for the gas pipeline because it helps the most people in the state. He also expressed concern that many people speaking to the Council today were bringing up subjects of no direct relevance to the policy issues before the Council.

Johnny Brower, a resident, expressed deep concerns to the Council about alienation felt by many North Slope people over changes thrust on the region by economic decisions made far away. He considers himself a "non-U.S. citizen" but still a Native American, and is proud of it. He feels frustrated because despite opposition of local people to many types of development over the last 25 years, there is still drilling. "You're forcing it on people who don't want to accept it," he said. "We don't want sickness, anger and anxiety. We want to live a healthy, well-balanced life with the proper resources."

Lucy Leavitt, a resident, described her own family's experience with public services, to illustrate the importance of property taxes to the Borough. She and her husband built a home for their family and were fortunate enough to be hooked up to electricity and gas, but not underground sewer and water. They pay 12 cents per gallon for delivered water and pay to have sewage taken away by municipal services. A few years ago the underground sewer and water system was extended to a block from her home. People there now pay $69 per month for unlimited water. She petitioned the Borough to have sewer service extended but was told the extension would cost $10 million and there is no money for it. Property taxes are the only way the Borough has to pay for such services, she told the Council. The issue has immediate and serious consequences for her family. When problems developed with the sewage tank in December, the family had to wait until spring to have it repaired. There were delays in getting the repairs made, and raw sewage leaked out around the house and created health hazards for her two young children.

Alaska Highway Natural Gas Policy Council

AGENDA

August 2, 2001, 10:15 a.m. to 6:00 p.m.
Juneau Baranof Hotel

I. Subcommittee Session #1
   - A. Alaska Hire (AJ Room)
   - B. Federal/International Action (Room 307)

II. Lunch Break

III. Subcommittee Session #2
   - A. Environmental Considerations (Room 307)
   - B. Access to Instate Gas and Future Opportunities (AJ Room)

IV. Break

V. Public Hearing

   - A. Opening remarks by Co-Chair Jim Sampson
   - B. Welcoming remarks by Mayor Sally Smith
   - C. Remarks by Governor Tony Knowles
   - D. Presentation from DNR Commissioner Pat Pourchot
   - E. Public testimony

Alaska Highway Natural Gas Policy Council

Juneau Public Hearing Summary
August 2, 2001, Baranof Hotel

Co-chair Jim Sampson convened the meeting. A moment of silence was held in memory of the passing of Rosemarie Maher, a Council member who was president of Doyon, Ltd., who recently passed away in Fairbanks.

Juneau Mayor Sally Smith welcomed the Council to the capital city. She was pleased that a public hearing on an issue of such statewide importance as natural gas policy would be held in her community.

Governor Knowles made introductory comments, indicating that the natural gas pipeline will help pull Alaska together because its benefits will be seen in many parts of the State. Southeast Alaska has a contribution to make as a staging area for equipment and supplies being moved to construct the highway gasline, the governor noted.

State Resources Commissioner Pat Pourchot gave a presentation on the proposed pipeline and changes in U.S. gas markets that now make it a possibility.

Michael Hurley, representing the North Slope gas producers working on the pipeline, gave an overview of the consortium's summer work, including its assessment of two routes and goal of completing cost estimates and other analyses by the end of the year, to be ready to apply for permits.

Fairbanks Mayor Rhonda Boyles, a Council member, asked Hurley if the "message" the Council heard in Barrow, concerning deep opposition to the northern, offshore route, was received by the producers group.

Hurley replied that it had. "The message we're getting from Alaskans is clear and consistent," he said.

Governor Knowles asked that the producers add "subsistence protection" to their list of goals for the project, along with environmental protection, an economic project and other goals.

Rep. Ethan Berkowitz asked why the liquefied natural gas (LNG) export option is not included among the options.

Hurley replied that a separate industry consortium, the LNG "sponsor group," is working on this. BP and Phillips, two of the three members of the producers' group working on the lower 48 pipeline, are also involved in that effort. ExxonMobil, the third member of the lower 48 pipeline group, has participated in past studies on the LNG option. At this time the lower 48 pipeline looks like the "most likely" way to commercialize the gas, Hurley said.

Charlie Cole, a Council member, asked if the decision between a highway and northern, offshore route would be made mostly on economic grounds.

Hurley replied that economic considerations are probably the most important factor at this point.

Esther Wunnicke, a Council member, asked if the producers' views of the economics are affected by whether or not they are owners of a gas pipeline.

Hurley replied that their views on the economics would be influenced by ownership.

Council member Bill Corbus asked how the consortium felt about possible State equity participation in the project.

Hurley said the producers are not opposed to State involvement. "We're in discussions with most of the major pipeline companies in the U.S., also," but the first issue to be resolved is whether an economic project can be developed. The ownership structure will be developed later.

At the suggestion of the Council, Hurley briefly described the concept of an "open season," where a pipeline being developed as a "contract carrier" would have a period where gas producers or others could "nominate" future gas for delivery, which will allow the pipeline to be sized for those needs. "Contract carriage" is the common form of legal organization for gas pipelines. This was compared to the "common carrier" organization that is common for oil pipelines, including TAPS, where the pipeline is open to all offers of oil, with "nominations" in effect held every month.

Robert Venables, economic director of the City of Haines, told the Council that the community is in a position to play a major role in support of gas pipeline construction and in marketing of gas. Haines has a deepwater port and, thanks to recent highway improvements, good roads to Fairbanks. There were good reasons why the federal government selected Haines as the starting point for the military fuel pipeline to the Fairbanks area during World War II, he said.

The community has had a number of contacts with members of the producers' group studying logistics issues. Both Haines and Skagway are in good positions to support highway route construction, with Skagway supporting construction from Whitehorse south and Haines supporting Whitehorse north. Haines is also working cooperatively with Haines Junction, in the Yukon Territory. The two communities will be able to work together to provide support services.

Following construction, Haines can be a site for manufacture of gas into LNG for shipment to Southeast communities, and possibly to Pacific export markets. There is a relatively short distance for a "spur" pipeline connection to the larger trunk pipeline.

Council member Brian Davies asked what expansions of facilities are required to accommodate construction.

Venables replied no expansion, or very little, is required. There is ample port capacity and sites for on-land storage and staging. Only minor improvements would be needed.

Bill Leighty told the Council that he represents a small charitable foundation interested in new energy technologies. He urged the Council to consider future possibilities of conversion of methane to hydrogen and future conversion of the pipeline to transport hydrogen. An advantage of this is that carbon dioxide extracted in the hydrogen manufacturing process could be used for enhanced oil

recovery. If there are future "carbon credits" allowed for projects that use CO2 instead of releasing it into the atmosphere, these credits would benefit the project. Large markets for hydrogen don't yet exist, he acknowledged, but with prospects for hydrogen use in large-scale application for fuel cells, the market will develop.

Loren Gerhard, executive director of the Southeast Conference, told the Council that the resource industries that have been the mainstay of the economy of Southeast — timber and fisheries — are both suffering, and tourism has not yet grown to the point where it will replace these industries. The Conference, made up of municipalities, other organizations and individuals, sees the highway gas pipeline route as a potential benefit to Southeast through logistics support activity. Haines, Skagway and Juneau are well positioned to serve the project, but it's possible that Ketchikan could even play a role. A spur line to Haines is the shortest route to tidewater for an LNG project, he pointed out.

Tim Sunday, representing the Teamsters Union 959, said construction workers in Southeast hope to work on a highway project. Juneau also hopes to get a crack at work on the project, although Juneau would play a supporting role to Haines and Skagway, he said.

Dave Hunz, a Skagway city council member, told the Council his community has traditionally served as a "gateway" to the Yukon Territory. Skagway has a deepwater port and a road to Whitehorse capable of handling heavy loads.

Fred McCorriston, president of the White Pass & Yukon Railroad, said Skagway is an important logistics and transportation center for the Yukon and has the longshore skills and experienced truck drivers needed for pipeline work. There is an existing ore terminal which can be used.

Sue Schrader, representing the Alaska Conservation Alliance, said the environmental organizations she represents strongly opposes all pipeline routes that invade undeveloped, frontier areas and ecosystems, particularly the northern offshore route. The Alliance is not now supporting any particular route but urges that any project that goes forward meet strict state, U.S. federal and Canadian environmental requirements.

Charlie Cole asked why the offshore route is opposed.

Schrader said the concern is with an "unproven" technology of pipeline burial under the Arctic pack ice. "It could put the whole ecosystem at risk," she said. "We feel the 'over-the-top' route appears to present the most potential environmental impacts."

In response to questions from Council members, Schrader said her groups will be more favorable toward a pipeline route following existing infrastructure. She did mention concerns with talk of "streamlining" regulatory procedures. When this happens, usually the level of public notice and public involvement is reduced.

Resources Commissioner Pat Pourchot explained that the kind of "streamlining" contemplated in the Administration was more efficient functioning. The effort now is to bring all issues to the table early so that resolutions can be worked out. That will save time later.

Schrader replied that the Legislature had enacted two bills including provisions for permit "streamlining" that did affect the level of public involvement.

Frank Brown commented that he had seen national television interviews on ANWR in which the president of the Sierra Club recommended that Alaskans develop natural gas instead of opening ANWR.

Don Etheridge, who represents the AFL-CIO in Juneau, said the labor groups he represents would like to see a spur pipeline built to Haines from an Alaska Highway pipeline, and the economic boost to Southeast Alaska that this would bring. He requested that Southeast workers be included in any training programs related to the pipeline. "Our motto is, hire from home first," he told the Council.

Frank Avezac, who is head of Alaska Interstate Gas Co., told the Council his company supports the Administration's efforts to have the gasline built down the highway. Haines is 150 miles from that route, he pointed out. His company is a utility with approval from the Regulatory Commission of Alaska to supply gas service to several coastal Alaska communities, from Ketchikan to Kodiak. Alaska Interstate is now looking to supply Southeast Alaska from Prince Rupert, B.C., but would welcome gas supply from the North Slope pipeline via Haines.

Jamie Parsons, representing the Juneau Chamber of Commerce, urged the Council to support a spur pipeline to Haines, and asked that a Haines spur be included in future presentations by the Council on options for using gas in the state.

Alaska Highway Natural Gas Policy Council

AGENDA

August 23, 2001, 2:00 to 6:00 p.m.
Valdez Convention and Civic Center

I. Presentation from Dick Peterson, Alaska Gas To Liquids Group

II. Presentation from Shane O'Leary, GTL Program Manager, BP

III. Presentation from Dave Dengel, Alaska Gasline Port Authority

IV. Public Hearing

- A. Call to Order: Co-Chair Jim Sampson
- B. Welcoming Remarks: Mayor Bert Cottle
- C. Presentation: Ken Freeman, Executive Director, Natural Gas Policy Council
- D. Public Testimony

Alaska Highway Natural Gas Policy Council

Valdez Public Hearing Summary
August 23, 2001, Valdez Convention and Civic Center

Council co-chair Jim Sampson opened the meeting.

Richard Peterson, president of ANGTL, Inc., gave a presentation on gas-to-liquids potential for Alaska. He briefly outlined his company's proposal, to build a 50,000 barrels/day GTL plant on the North Slope that would batch "clean" GTL diesel and naphtha down the existing TAPS pipeline. This could be a pilot for additional plants, which could be added incrementally as the market for clean diesel expands.

A North Slope GTL project could also enhance the economics of a gas pipeline and increase benefits to Alaska, Peterson said. The GTL project would provide the infrastructure for "batching" natural gas liquids that could be removed from the gas on the North Slope and shipped down the TAPS pipeline. These could be sold to a wider world market through Valdez, and used in Fairbanks, as opposed to the current proposal to ship NGLs through the gas pipeline and market them in Alberta. The market for gas liquids in Alberta, and the U.S. Midwest, is already saturated, he said.

Peterson critiqued two points made in a recent analysis by Cambridge Energy Research Associates (CERA). One is that taking gas liquids out of the gas pipeline in Alaska will weaken its economics. Peterson disagreed with this and said having the liquids available in Alaska would increase benefits to the state. Second, CERA missed an important advantage of fuels made from natural gas rather than petroleum — federal taxes are less on fuels from natural gas. This is worth 31 cents/gallon or $13 per barrel to a GTL diesel fuel, he said. Because of these advantages, Peterson said a GTL plant on the North Slope could pay the State $1.75 to $2 per mcf for its royalty gas, much higher than the netback values discussed for a gas pipeline.

Council member Ken Thompson asked if Peterson plans to use Sasol technology.

Peterson replied that his company was technology "neutral," that any proven GTL technology could be used, but that he does have an agreement with Sasol to license their technology. He pointed out that since Sasol doesn't license their technology to a project they don't participate in, this means that Sasol could be a partner in an Alaska GTL project.

A Council member asked for more information on the TAPS batching and gas liquids possibility.

Peterson explained that batching GTL diesel through TAPS would make batching of other liquids possible. Butanes, for example, are now blending with crude oil in TAPS. If these could be batched and sold separately, they would have a higher value than if just blended with the crude oil. ANGTL's proposal involves using physical "pigs" to separate the liquids in the pipeline.

GTL gives the state another option for using liquids, Peterson explained, by batching the liquids from the slope through TAPS rather than the gas pipeline. If liquids are shipped through a dense-phase gas

pipeline, problems are created for anyone wanting to tap the gas pipeline for gas offtake because the liquids must be handled also, creating more cost.

Peterson also said that the three major producers have not put forward GTL as an option because they claim it doesn't have enough value. ANGTL believes the majors have missed the important tax advantages.

A Council member observed that BP is investing $100 million in a GTL test plant near Kenai.

Peterson pointed out that other companies are far in advance of BP and Exxon in GTL technology.

A question was asked about energy loss during the GTL process, that 25 percent to 30 percent of energy might be lost.

Peterson said that if it were looked at as a straight conversion, the process is 70 percent to 75 percent efficient (i.e. 25 percent to 30 percent loss of energy). However, if waste heat from the GTL process were captured and used, and other potentials of the process taken advantage of, such as manufacture of pure hydrogen, the efficiency of Btus in and Btus out is more like 95 percent.

Council member Brian Davies observed that this assumes beneficial uses for the waste heat and other products.

Peterson pointed out that water generated by the project could be used in waterflood, and that nitrogen could be used in enhanced oil recovery.

Council member Peg Tileston asked who is involved in ANGTL.

Peterson said he has a partner, and that Forest Oil Corp. was backing the venture. Mossgas, a South African company that operates a commercial-scale GTL plant, is an advisor and is also interested in becoming involved in an Alaska project.

A question was asked about how much GTL product could be made from North Slope gas.

Peterson replied that he believes the North Slope has the potential to produce 1 million barrels per day of liquid GTL products. More likely is 300,000 barrels per day produced by several GTL plants built in increments of 50,000 barrels/daily, which seems to be the optimum capacity for commercial-scale GTL plants. The project should begin with one plant producing 50,000 barrels/daily, batched through TAPS. This would establish Alaska "clean diesel" in the market, which could then be gradually expanded.

If the State wished to do something with its royalty gas, ANGTL could move forward with a project, Peterson said.

Council member Esther Wunnicke asked about transportation costs.

Peterson replied that his analysis assumed $2.80 per barrel tariffs for the TAPS pipeline and $5 per barrel for marine transportation to the West Coast.

Shane O'Leary, GTL project manager for BP, presented information on BP's project.

O'Leary explained the process as essentially taking methane, the main component of natural gas, and combining it with steam in a reforming process, making a synthesis gas. The second stage is the Fischer-Tropsch chemical conversion, which converts the synthesis gas into paraffin waxes. A third stage is conventional refining, which converts these waxes into different products, such as diesel.

The first stage - reforming - is where 65 percent of the capital cost of a GTL project is, and this is the heart of the BP strategy. GTL is now inefficient. For 100 units of energy in, you get 60 out. A lot of work is being directed at ways of capturing waste heat and lowering the capital cost.

GTL plants that have been built were done for reasons of national interest. Germany built GTL plants during World War II because there was not access to enough conventional oil. South Africa built plants because international boycotts cut them off from most supplies of oil. More recently, Sasol and Chevron are working on a GTL project in Nigeria, but this is mostly to capture gas that is now flared and wasted. What could be the first truly commercial GTL plant is a project planned by Sasol in Qatar. But little is known of the commercial terms of this project, whether there could be subsidies.

BP has been working on GTL since the 1980s, mostly focused on the reformer stage. Their next step is the plant at Nikiski, which will test a new compact reformer, which promises to reduce costs. The test results from the Nikiski plant can be scaled up to a commercial plant.

Other products can be made from synthesis gas produced through a compact reformer besides "clean" diesel, including methanol and fertilizer. Agrium, for example, now makes fertilizer from a synthesis gas made from natural gas through a reformer.

Dick Peterson addressed very well the high quality of products made through a GTL process. The diesel has no sulfur, nitrous oxide or aeromatics (which produce the smoke seen from diesel trucks and buses). There are other products, such as naphtha, a petrochemical feedstock. Naphtha made through GTL has a 10 percent to 15 percent quality differential than conventional naphtha. Jet fuel made from GTL is very high quality, leaving no contrails. Contrails are a serious environmental problem in some areas of high air traffic, such as parts of Europe. BP is looking for ways to make its GTL process economic with a conventional 30,000 barrels/day plant.

The big advantage of GTL is that the plants can be build incrementally, expanding production with the market. This isn't the case with a gas pipeline or liquefied natural gas project, where all the costs are "up-front." The compact reformer technology being demonstrated at Nikiski is proprietary with a partner. "But BP is not hung up on property rights to technology, unlike other major oil companies. We just want to commercialize our gas."

The best Fischer-Tropsch GTL technology is the slurry-bed reactor, like Sasol has developed, O'Leary said. BP is working on slurry-bed technology also.

Today the conventional wisdom is that a GTL plant will cost about $25,000 per barrel of daily capacity, built on the U.S. gulf coast. A 30,000 barrels/day plant would cost about $750 million. BP believes that if costs can be reduced to about $20,000 per barrel of daily capacity, there will be a lot

of excitement about GTL. Once these plants are beginning to be built on a mass scale, the cost structure will come down more. BP believes costs can be reduced to about $17,000 per barrel of daily capacity, at which point GTL will be on par with liquefied natural gas (LNG). This is on the gulf coast, however. The rule-of-thumb is that it costs 25 percent more to build a plant on the North Slope, compared with the U.S. gulf coast.

O'Leary said construction of the Nikiski plant required 150 to 200 workers, and that the biggest problem was securing skilled craft labor. BP's target for starting up its Nikiski plant is second-quarter 2002. The plant is intended to operate for five years, but there are many types of testing that can extend the operating life. The facility is designed so that a technology system, such as a new slurry-bed Fischer-Tropsch reactor, can be "plugged in" to the compact reformer. One additional technology now being tested at the plant is a new type of solid oxide fuel cell that could be 30 percent to 45 percent more efficient than conventional fuel cells, and generate one-third less carbon dioxide. BP sees potential for installation of these new fuel cells on platforms and drilling rigs. There could be many other uses as well.

Council member Bill Corbus asked about the cost of Fischer-Tropsch diesel, made through GTL.

O'Leary replied that the environmental properties of the fuel should command a higher price. "But unless you're in a place where a conventional pipeline or LNG won't work, GTL isn't economic." BP still looks at the economics in a "holistic" sense. "We don't see it as economic until we get the costs down. We do think there is a good market for Fischer-Tropsch GTL diesel, but we still need to get costs down. We're almost there. It's right on the cusp. It's really close."

Council member Esther Wunnicke asked about the gas price assumptions used in the economic analysis.

O'Leary replied that a gas price of 30 cents per mcf is assumed. "Even at 30 cents, it still struggles. We've got to get costs down."

Council member Brian Davies asked if BP had taken the tax advantages mentioned by Dick Peterson into consideration.

O'Leary said BP's analysis was without tax considerations. "It's an interesting point that we haven't researched. I'm going to take his paper back," for further review.

Council member George Wuerch observed that if GTL diesel has such clean properties, California would probably offer incentives.

O'Leary said that refiners will say they don't need GTL technology, that they can install desulfurization facilities and make clean diesel more cheaply than through GTL. So, the industry's "downstream" is not enthused about GTL.

Council member Ken Thompson said that at a Girdwood conference on GTL earlier this year he had understood that it will take about 10 years to achieve the 20 percent reduction.

O'Leary said that BP's view is that it will take five years to achieve the reductions. Some interesting new technologies are also being experimented with, such as use of ceramic membranes.

Thompson said he also learned of dramatic cost reductions in natural gas liquids technologies at the Gi[illegible]wood conference, which will improve the economics of businesses related to propane and butane. It pinpoints the NGLs as a major issue for Alaska and Alberta.

O'Leary said BP had always said there will be more than one commercialization strategy for gas from the North Slope. The key is to get the first commercialization accomplished, through a gas pipeline. Once that happens, there will be an explosion of activity, exploring for more natural gas. BP ranks the pipeline first, GTL second and LNG third in order of options.

Co-chair Jim Sampson said BP's original plan was to build its test plant on the slope. He asked why this was changed to Nikiski.

O'Leary said because the plant is "stick-built" (built on site, not modularized) it's cheaper to build near Kenai, where there is also a supply of gas and labor is available. It's also closer for the scientific staff, who will be based in Anchorage.

Dave Dengel, acting executive director of the Alaska Gasline Port Authority, welcomed the Council to Valdez and introduced Charlie Cole, who is a member of the Authority's board (as well as a Council member).

Cole described how the Authority was first formed, at the initiation of the mayors of Valdez, Fairbanks North Star Borough and the North Slope Borough, and how it was formed with approval of voters in all three municipalities. The financial concept of the Authority is that it would retain earnings in Alaska, paying 60 percent of net earnings to the State, 30 percent in a distribution to all Alaska municipalities and reserving the remaining 10 percent to the three municipalities which had initiated the Authority.

The Authority built a team of legal, financial and construction advisors and consultants, including Bechtel. The first analysis was on an all-Alaska pipeline to Valdez, with an LNG export project. This was found to be uneconomic. The plan was then shifted to a combined LNG-export and lower 48 pipeline, with six billion cubic feet (bcf) daily produced off the slope and transported to a hub at Delta, where 3 bcf/day would move to the lower 48 and 3 bcf/day would move to a Valdez LNG plant, which would have a capacity to produce 15 million tons per year of LNG.

The cost assumptions included $4.2 billion for a conditioning plant at the North Slope, $9.7 billion for pipelines to Delta and branches to Valdez and the Canada border, and $3.65 billion for an LNG plant at Valdez. The total capital cost would be $18 billion. Adding "soft costs" of $5 billion for interest paid during construction, an owners' contingency fund of $900 million, and $1 billion in debt service, brings financing costs to $7.8 billion, for a total of $26 billion.

"This may not be the best or only project, but it's a start," said Cole.

Co-chair Jim Sampson asked what happens at the Canada border.

Cole said the pipeline obviously would extend through Canada to the heartland of the U.S. He introduced Rigdon Boykin, financial advisor to the Port Authority.

Boykin said the Authority has had several conversations with Foothills Pipe Lines, and a gas tariff through Canada to Chicago is assumed to be $1.20 per mcf based on information from Foothills.

Studies by the Authority show that capital costs per ton of a pipeline and LNG plant would be high, about $740 per ton of LNG produced, but the revenues from a liquids extraction business could offset this, to the point that costs of LNG would be reduced to about $400 per ton. This is in the range of competitiveness with other, competing LNG projects.

The Port Authority proposed to finance the project 100 percent with debt, using a project-financing approach. The financial plan includes a 2.08 debt coverage ratio as a minimum and 2.5 as an average, in terms of revenues over debt. The tax-exemption of the project is worth $3 billion to $6 billion in value to the project, compared to what financing costs for a privately-financed project would be.

Results of the financial analysis show the project able to pay producers 75 cents/mcf for gas on the North Slope. Based on this, the State would receive $371 million per year in royalty and severance tax, $148 million per year for a payment-in-lieu of corporate income tax, and $222 million per year in a direct payment to the State treasury. Separately from this, municipalities would receive $148 million per year. Producers would receive $1.7 billion per year. The analysis assumes a $3 per mcf price for gas in Chicago and $2.50 per million Btus for LNG in Valdez (one mcf roughly correlates to 1 million Btus). The Valdez LNG price assumes a $3.40/million Btus price for LNG delivered in Asi .

One of the primary benefits of a port authority is that is would not be subject to Federal Energy Regulatory Commission (FERC) regulation. This is based on an exemption from FERC review in the federal National Gas Act, exempting public entities from regulation. The State of Alaska would have regulatory control over the project.

Co-chair Sampson opened the public hearing portion of the meeting.

Mayor Bert Cottle welcomed the Council to Valdez. He pointed out that state revenue sharing to local governments has been reduced from $110 million per year to about $30 million. The Port Authority has developed its plan and put it out for public review, and no one has yet come up with a better plan. "Let's have no more studies, no more politics. The best way to kill a project is to study it." The gas on the North Slope is Alaska's gas. "It's time we stood up to take care of Alaskans first." As for the producers, it's "use it, lose it or tax it." If the producers' study comes back to show that only the "over-the-top" (northern) route is economic, "then we should say, no gas."

Ken Freeman, executive director of the Council, gave a prepared presentation on the proposal for a North Slope gas pipeline and the evolving market for Alaska gas in the U.S.

Curtis Thayer, representing the producers' group working on gas pipeline studies, gave a prepared presentation on the producers' project.

At the conclusion of Thayer's presentation, Council member Jerry Hood asked Thayer why "economics" is always listed as the top criteria for the study, and why "use of gas" as a resource by

Alaskans isn't listed among seven criteria. It gives the impression that economics is the number one consideration, he said.

Thayer responded that benefits to Alaskans is one of the criteria for analysis.

Council member Ken Thompson noted that the presentation speaks only of lower 48 markets, and that Alaskan markets for gas or gas liquids are not mentioned.

Thompson went on to comment that there is more to an analysis than consideration of market forces. An example is ARCO's consideration of double-hull tankers with redundant steering and engine systems, for added safety. "The present value calculation was higher without all that extra stuff, but we chose a path that included the environmental concerns of Alaskans. It was the right thing." The gas pipeline is a complex issue, and a "leader" is needed to step forward, he commented.

Council member Peg Tileston asked Thayer if anyone is making 52-inch high-pressure pipe.

Thayer said that no steel producer was making pipe of this type, as of yet.

Council member Charlie Cole noted that the 1977 U.S.-Canada agreement on the ANGTS stipulates that gas will be made available to remote communities in the Yukon Territory. Are the producers willing to make similar commitments in federal legislation?

Thayer said the producers are very supportive of supplying gas to Alaska communities in the vicinity of the pipeline, but how this gets done is up to the communities.

Council member Jerry Hood said he would like it said for the record. "You are in support of Alaska gas to communities but you don't want it in legislation. What are you in support of?"

Thayer replied that the issue is inappropriate for legislation, but is an important statement of principle.

Cavan Carlton, of Williams Energy, described his company's activities in Alaska and a study underway of manufacturing petrochemicals from North Slope gas at the company's Fairbanks refinery. *(Note: a more complete presentation on this project was made in the Council's September 25 Anchorage meeting and is in the summary prepared for that meeting.)*

Dell Wilson, of Copper Center, told the Council he is president of Ahtna Construction, which is currently a major contractor to Alyeska Pipeline Service Co. Ahtna supports a pipeline through Alaska to Valdez, he said. An "over-the-top" northern pipeline would not benefit Alaskans.

Robert Wilkinson, representing Copper Valley Electric Association, told the Council his association supports a gas pipeline to tidewater. Electricity now costs 16.4 cents/Kilowatt hour in Valdez, double the average cost in the state's "railbelt" communities. A gas pipeline to an LNG plant in Valdez would not only make gas available for local electrical generation, but waste heat from the Valdez plant would further reduce costs.

Bill Walker, city attorney for Valdez but speaking for himself, said he was born in Fairbanks and has lived for much of his life in Valdez. He worked on the TAPS project and saw its benefits first hand. He has been active in efforts to commercialize gas ever since the TAPS pipeline was completed.

Walker said his biggest concern is that the producers will find that only an "over-the-top" route is viable, or that neither the highway or "over-the-top" route is viable. Yet there is a market for the gas, and what's needed is a consortium of purchasers of the gas to team with pipeline companies to build a project if the producers don't want to do it.

CERA has pointed out that if an Alaska project is delayed to the point that the present market window closes, there may not be another opportunity for Alaska gas for 15 years.

Scott Heyworth, proponent of a trans-Alaska gas pipeline and LNG project, told the Council he is supporting an initiative campaign to encourage a trans-Alaska pipeline because most Alaskans want it. The new bill gas producers have circulated in Washington, D.C. would centralize too much power on gas issues in the President's office, and would not provide for use of the gas in-state.

Dave Dengel, city manager of Valdez, said the city has been involved in efforts to build a trans-Alaska gas system for many years. The LNG export project would have wide benefits throughout the state, including Southeast and Southwest Alaska. The port authority concept would benefit many Alaskans.

John Devens, a Valdez resident, said he is not convinced by the producers' statement that if an "over-the-top" northern pipeline is built, a separate pipeline to Fairbanks to serve Alaskans will be built. He urged decisive action to "send a clear message" that Alaskans want a project that will benefit them.

Lynn Chrystal, a Valdez resident, said the Port Authority has made a big improvement on the Alaska Highway pipeline proposal, with a "Y" system that would bring a spur line to Valdez. A northern route, on the other hand, "is like sending all of our salmon Outside."
"If the big companies don't want to play, we should find someone who will," he said.

Rep. John Harris, state representative for the Valdez region, told the Council the Legislature has enacted a law that prohibits an "over-the-top" route. He said a gas pipeline through Alaska would make processing of the resource possible. Also, Yukon Pacific Corp. has signed a Project Labor Agreement, and the Port Authority anticipates signing one. The State's priority should be to have as much infrastructure in Alaska as possible.

John Downes, representing the Copper Valley economic development council and chamber of commerce, expressed support for the Port Authority concept. "It seems doable." He urged the Governor to work with the Port Authority in developing the project.

Pat Abney, an Anchorage resident, told the Council she supported an Alaskan route. She has been an Alaska resident for 40 years and recalls the 1964 earthquake, when Alaskans pulled together to face a big challenge.

Alaska Highway Natural Gas Policy Council

AGENDA

September 7, 2001, 9:00 a.m. to 4:00 p.m.
Anchorage Sheraton Hotel

I. Federal/International Action Subcommittee *(Yukon Room)*

Foothills Pipelines
John Katz & Bob Loeffler

II. Full Council meeting *(Ballroom A)*

Subcommittee Updates
Discussion

III. Environmental Considerations Subcommittee *(Yukon Room)*

Alaska Highway Natural Gas Policy Council

Anchorage Meeting Summary
September 7, 2001, Anchorage Sheraton Hotel

Council co-chair Jim Sampson opened the meeting.

Lt. Gov. Fran Ulmer made opening remarks. Despite press reports about the producers' concerns about a mandate of a pipeline route, the governor is continuing to work with the producers, she said. Ulmer outlined Gov. Knowles' 10-point proposal for federal legislation, which would designate the Alaska Highway route as the approved route and would include federal tax incentives to help the project.

Mike Navarre, chair of the Council's Alaska Hire/Buy/Build Committee, briefed the Council on meetings his committee had with Department of Labor and Department of Community and Economic Development staff on an Administration study of socio-economic impacts that is now underway. The producers' group is nearing completion on a socio-economic study and will present their information at the Council's next meeting. Navarre shared some preliminary information he was given by the producers' group.

He said his committee is considering recommending that a pipeline proponent make commitments on Alaska hire and training, similar to those made in the BP-ARCO charter commitments. One issue the committee is still grappling with is how to ask for commitments to use Alaska companies and contractors.

Bill Corbus, chair of the State Ownership Committee, reported his committee has held four meetings, two shorter sessions coinciding with full Council meetings, and two separate, longer sessions in which the group talked extensively with experts, including a consulting firm retained by the State to analyze the benefits of possible State equity in a gas project.

Corbus said the committee has identified four ways the State can finance an equity investment: through the Permanent Fund; the Constitutional Budget Reserve; the State issuing general obligation bonds; or sale of revenue bonds through the Alaska Industrial Development and Export Authority (AIDEA), or an AIDEA-type authority created to do the gas project financing. The committee reviewed State oil and gas tax policy with the Department of Revenue, focusing on tax structure (Alaska's taxes are both regressive and "front-loaded") and how that might affect a large gas project. The panel has not yet heard from the producers on taxes, however.

Corbus said the committee is likely to make recommendations both on a possible percentage of the pipeline the State might consider owning and the geographic area of participation, such as the section of pipeline from the North Slope to a major offtake hub in Fairbanks or Delta. Under a scenario where the producers choose not to participate, the committee will have an alternative recommendation for the State to work with an independent pipeline group.

In response to questions from the committee, Corbus outlined the main reasons why State equity should be considered: 1) it would create better control over the sale of State royalty gas; 2) it would ensure that other developers would have access to the system for transporting gas. Corbus said he did

not believe the investment would make a lot of money for the state (i.e. there might be better alternative ways of using the money) but other members of the committee have not yet weighed in on this.

Ed Rasmuson, a member of the committee, commented that he believed the committee is leaning toward a recommendation that the State make the investment. Corbus agreed. Rasmuson also commented that State investment would be a way for the State to know what's going on inside the pipeline consortium, an important advantage. Dave Rose, another member of the committee, commented that if the investment could earn 15 percent or greater, as seems possible, the return would be in the range that Permanent Fund Trustees might consider it.

Charlie Cole, chair of the Federal/International Action Committee, briefed the Council on meetings his committee has held.

In a meeting in Juneau, John Katz, the state's Washington representative, and Bob Loeffler, an attorney on contract with the State, gave the committee their views on legislation being proposed by the producers. Katz "doesn't think much" of the producers' bill, Cole said, because it aims to somewhat duplicate the expedited regulatory review process established two decades ago in ANGTA for the highway route. Under the amendments proposed to the Natural Gas Act, the Federal Energy Regulatory Commission (FERC) would have no choice but to issue a certificate to the producers group once certain conditions were met. Since the language is "route neutral" (it doesn't designate a route), in effect the provisions would allow the producers to control the choice of a route.

In a committee meeting Sept. 7, held just before the full Council meeting, another problem was discussed in some depth: a potential $4 billion liability on an Alaska Highway project pursued by Foothills Pipelines due to past investments by partners who withdrew from the project. Ken Thompson, a member of the committee, told the Council he believes this issue must be ironed out before the State can support Foothill's application. Cole said that as long as this issue is out there, there will be uncertainties as to how it will effect the pipeline tariff.

The committee will also be taking an in-depth look at how existing lease agreements governing the producers' responsibilities to make gas available for sale are affected by various proposals. For example, if an independent pipeline group were to propose a project, what would be the producers' responsibility to make gas available under existing lease contracts with the State?

Ken Thompson briefed the Council on the work the Access for In-state Gas Use and Future Opportunities Committee has been doing, including review of work related to in-state gas demand studies now underway by consultants to the State.

The committee is also looking at ways of delivering gas to rural communities, including possibilities of shipment of propane and butane as an alternative for communities at a distance from the pipeline. One problem that has been identified is that this pipeline will operate at high-pressure, carrying natural gas liquids with the gas. If there is a "tap" in the pipeline to supply a community, the liquids will have to be extracted from the gas before it can be used, creating additional costs. It may be that gas will have to be taken out at only one or two hubs where the liquids can be economically processed.

The committee reviewed State royalty-in-kind policy and has met with Texas state officials on how they handle their royalty-in-kind. The advice they got was not to "negotiate away" the right to take royalty gas in-kind. Regarding transparency in pricing, it is important for the State to sell some royalty gas in the market to gain information on pricing. Regarding access for gas off-take, it is clear through studies by CERA and others that the Alaska Natural Gas Transportation Act (ANGTA) has very clear language regarding rights to access. If the ANGTA law is not used for a pipeline, similar guarantees can be obtained through FERC proceedings or, as Texas does it, through the right-of-way lease process for state lands. Access into the pipeline is a more serious issue. If the pipeline is operated as a contract rather than common carrier, there are uncertainties. The committee is still looking at this, Thompson said.

Regarding other gas use options, the economics of liquefied natural gas (LNG) still look doubtful but Yukon Pacific Corp. has an active project and if a hub is available, an LNG project may yet materialize. Gas-to-liquids (GTL) is an option but improvements in technology will take 5 to 10 years to make GTL commercial. In the meantime, there are substantial advances occurring in cost reductions of natural gas liquids processing. Williams Energy is seriously studying a large liquids plant that would be an addition to their Fairbanks refinery.

Peg Tileston briefed the Council on work the Environmental Considerations Committee is doing. Several meetings have been held with the Departments of Fish and Game and Environmental Conservation, Division of Governmental Coordination and the Joint Pipeline Office. The committee is focusing on broad policy issues rather than specifics, such as access to information and early consultation with communities on large projects. Once design and engineering has started, it is too late to get significant community involvement, she said.

The committee is also concerned with whether adequate funding is available to agencies reviewing pipeline applications, and problems, particularly for State agencies, in recruiting staff.

Alaska Highway Natural Gas Policy Council

AGENDA

September 25, 2001, 8:30 a.m. to 5:00 p.m.
Anchorage Hilton Hotel

I. Access to In-State Gas Subcommittee — *Lupine Room*

II. Alaska Hire Subcommittee — *Cook Inlet Boardroom*

III. Environmental Considerations Subcommittee — *Prince William Boardroom*

IV. Federal/International Action Subcommittee — *Prudhoe Bay Room*

V. Full Council Meeting Call to Order — *Denali Room*

VI. Working Lunch

VII. Federal Legislation/Congressional Update

VIII. Alaska Natural Gas Producers Pipeline Team

IX. David Hall, Deputy Land Commissioner, Texas General Land Office

X. Break

XI. Alaska NGLs and Petrochemicals, Cavan Carlton, Williams Pipelines

XII. Council members comments/discussion

XIII. Business meeting

Alaska Highway Natural Gas Policy Council

Full Council Meeting Summary
September 25, 2001, Anchorage Hilton Hotel

Co-Chair Jim Sampson convened the meeting.

Council member Charlie Cole led an extensive discussion of the governor's 10 points in proposed federal legislation.

Here are the 10 points:

1) Mandate the already permitted Alaska Highway route as the preferred gasline route.

2) Provide access to the gas for Alaska communities for energy and to businesses for new development;

3) Provide access to the pipeline for new discoveries that will keep Alaska's oil and gas industry healthy through new leasing, exploration and production;

4) Expand opportunities for new pipeline participants to include existing producers, pipeline companies, and major Alaska companies such as Arctic Slope Region, Inc., CIRI and Doyon regional corporations.

5) The legislation must include a provision for Alaska and Alaska Native hire;

6) Must include a provision to use Alaska businesses;

7) Must include a project labor agreement for the construction, operation and maintenance of the pipeline, and worker training to prepare the thousands of needed skilled workers.

8) A priority for the use of American and Canadian steel.

9) Federal legislation must find that the Alaska Highway gas pipeline is in the national interest, including the interest of consumers, businesses, organized labor and manufacturers who would help build it.

10) Include economic incentives such as accelerated depreciation, an investment tax credit and gas tax credit to give investors an additional level of confidence.

There was an extensive discussion of the 10 points and debate on several. Speaking by phone from Washington, D.C., John Katz, the state's Washington representative, said a "joint board" approach, as suggested by Nan Thompson, chair of the Regulatory Commission of Alaska (RCA), is the appropriate mechanism to coordinate action by the Federal Energy Regulatory Commission (FERC) and the state's RCA. There is precedent for such joint boards in the telecommunications field.

Ken Thompson, a Council member, said the governor's principle on access to a pipeline allowed for new exploration on the Slope and new gas brought into the pipeline. It's important that FERC understand this so that rulings are not made that hinder access and future exploration.

Anchorage Mayor George Wuerch raised discussion over a provision for preferential "Alaska hire" when all estimates show there will be more than enough jobs for Alaskans, and that construction is now so busy that hiring halls are empty. There should also be a provision providing for pipeline impact aid to communities affected by construction, he said.

From Washington, John Katz said there was precedent for local impact aid in federal law in the Outer Continental Shelf royalty revenue sharing provisions.

Council Co-Chair Jim Sampson acknowledged the state's economy is larger and more mature than when the TAPS oil pipeline was built, and thus better able to absorb impacts, but the Alaska hire provision is still useful to encourage the support of training of Alaskans. Charlie Cole agreed with this, that the provision will encourage the building of skills among Alaskans.

Brian Davies, a Council member, urged the Council to be "careful what we ask for." To ask that the maximum number of jobs be "dedicated" to Alaskans while also asking for impact aid is contradictory and would undercut the credibility of the state's requests in Congress.

Jim Jansen, a Council member, observed that Alaska labor markets are now extremely tight. In his company (Lynden Tranport), "we hire for the stable market and contract out for the peaks in work." The point is that it might be better to hire outsiders to do pipeline work, and let them live in camps, and keep local people in permanent local jobs.

Carl Marrs questioned the provision for Project Labor Agreements and questioned whether this, if applied for operations, would cut out competition from merit shops (non-union).

Jim Sampson relied that if labor support were desired to move the legislation in Congress, a PLA would be helpful.

Mike Navarre, a Council member, questioned the contradiction between the "preference for Alaska businesses" and preference to unionized firms through the PLA requirement.

From Washington, John Katz commented that this was drafted to be similar to the House-passed ANWR bill, which includes a PLA provision, except that this would focus on construction while the ANWR PLA, in the House bill, includes operations. Katz noted that for a period of years TAPS oil pipeline maintenance and operations work was done under a PLA.

Navarre acknowledged the need for labor's support to get the legislation through, but still felt there was a contradiction between a PLA provision and a preference for Alaska business.

Marrs suggested that the proposal for training for Alaskans include unions, under a PLA, as well as companies.

There was discussion among the Council members on the potential liability of requests by withdrawn partners for repayment of past investments, an issue which could cloud the ability of the current ANGTS partners to finance the project.

John Katz said the Administration is still waiting to see if the issue can be resolved privately between the commercial interests.

In discussing the overall 10 points, Brian Davies observed that many of the items will add to costs, creating a lower wellhead value of gas. "We're asking for short-term benefits and foregoing the longer-term benefits," of a higher value for the natural gas on the Slope.

Jim Jansen said he objected to the requirement that U.S. and Canadian steel be used. He suggested softening the language to include terms like "if available and reasonably priced."

George Wuerch said he supports the overall legislation but doesn't want to make the 10 points "an ultimatum. All 10 points or else."

Esther Wunnicke commented that the Council should endorse the legislation in principle and leave the wording to others.

Peg Tileston said it was important for Alaska to "send a message" to Congress that the state needed special consideration. "We don't want FERC to put us in a box, treating us like other states."

Ethan Berkowitz said the mandate for a highway route still bothered him. "We haven't disproved the opportunity for a liquefied natural gas (LNG) export project to my satisfaction."

John Katz said the concept of future expansions, including a spur and LNG export project, is embedded in the governor's legislation.

Jack Roderick commented that several of the governor's points are extremely important, such as the mandate of the highway route and the joint board with FERC. He was concerned about adding too many "extras" that were possibly less important.

John Katz replied that there is always a fine line between asking for too little and too much. The 10 principles incorporated the most important concepts that were important both in the nation's as well as the state's interest.

At Charlie Cole's request, the Council voted to support the 10 principles. A majority of the Council voted to support them.

Robbie Schilhab of ExxonMobil Corp. and Joe Marushack of Phillips Alaska Petroleum Co., two of three members of the management committee of the producer's consortium, presented the interim results of the economic evaluation of the project.

The current analysis shows both the northern and southern route to be uneconomic, "at present," said Schilhab. The conclusion is based on early numbers, and the companies are now concentrating on areas where they might achieve cost reductions.

The current plan assumes a northern route of 1,803 miles (to Alberta), a southern route of 2,139 miles. A stand-alone Mackenzie Valley pipeline would be 1,140 miles, he said. The study assumed gas throughput at 4.0 to 4.5 billion cubic feet daily, with the project designed so that volume could be increased to 6 billion cubic feet/day in the future, he said. A 52-inch diameter thick-wall pipeline, operating at 2,500 pounds-per-square-inch operating pressure, is assumed in the study, he said.

Costs of a northern, offshore route are estimated at $15.1 billion, with a longer southern route, through the Interior and along the Alaska Highway, estimated at $17.2 billion, he said.

The "tariff," or the cost for transporting gas from the North Slope to markets in the lower 48, is estimated at $2.39 per thousand cubic feet (mcf) for the southern route and $2.07 per mcf for the northern route.

Cumulative government revenues on both routes were about equal, however, at $66.2 billion for the southern route and $68 billion for the northern route, the analysis showed. This includes revenues to Alaska, Canada, provinces of Canada and the U.S. government. Alaska's share of that would be $22.7 billion for the southern route and $24.1 billion for the northern route.

However, a key part of the analysis that was questioned by Council members was a 15 percent discount rate used in the net present value calculation of cumulative cash flows. The discount rate can be assumed to be similar to an expected rate of return for the project, including gas production revenues.

Thompson said that using a 12 percent discount rate the project might be break-even, and if the benefits of the governor's proposed federal tax incentives and the value of the NGL business are added, "this is a commercial project." Thompson said, "I calculate another $3 billion to $4 billion a year in revenue. There's a big component of this that is undervalued." Thompson said his figures were based on assumptions that the liquids shipped would total 100,000 to 150,000 barrels/day. "Is there something we're missing?"

Schilhab said the analysis does not now include any value for downstream sales of liquids. The producers assume the pipeline will carry about 60,000 barrels/day of liquids.

He said the cost estimates were "unclassified" at this point, meaning they were so rough there couldn't yet be a plus-or-minus percentage given. By the end of the year the group intends to have estimates plus-or-minus 30 percent.

Brian Davies asked if it was customary with large gas pipelines to go to an "open season" (a call for gas nominations) with the project still plus-or-minus 30 percent in cost. Schilhab replied that this might be done with this project, and if costs were on the high side, consultations with shippers would have to be done.

He said that the current producers might have to sign on to the project even with the 30 percent probability, but that non-owners, such as companies now exploring for gas who might nominate future production, could be given an "out" if there were cost increases.



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ATTACHMENT "A'
INITIAL QUESTIONS

GENERAL BACKGROUND

The Committee conducted a number of public hearings on the construction of a pipeline to deliver natural gas to the lower 48 or to a liquefaction plant in Southcentral Alaska for delivery of liquefied natural gas to Asia, Mexico or California. Before several of these meeting the Committee, the Committee had sent various questions regarding the respective jurisdiction of the FERC and Regulatory Commission of Alaska (RCA) over a natural gas pipeline, upstream access to the pipeline, and downstream access to a pipeline to the FERC, the RCA and the law firm of Morrison & Foerster (Mofo), which represents the governor. The Committee received a lot of good information from the agencies, Mofo, and others about these issues. However, some of the information seemed conflicting or incomplete. Additionally, more questions, which I will break down by subject area, were raised. These questions are of vital importance to Alaskans and this body in making informed decisions regarding Alaska's ability to benefit from a natural gas pipeline. It is important that the Legislature get its own expert legal advice regarding these issues.

UPSTREAM ACCESS

Background

One group that desires to build a natural gas pipeline to the lower 48 and become its owner is composed of three largest owners of gas reserves on the North Slope, BP, Phillips, and Exxon (Owner Producers). The Owner Producers are among the largest companies in the world. Originally, under ANGTA, the Owner Producers were prohibited from owning any portion of the Alcan pipeline because of anti-trust concerns. ANGTA was later modified to allow the Owner Producers to own some portion of the pipeline. Since the time of that amendment, however, the FERC has unbundled pipeline services on the downstream end to allow for more competition. If the Owner Producers own the pipeline, many competitive concerns may arise, particularly with access to the pipeline by other potential shippers. Those potential shippers include the State of Alaska, which owns about 12.5% of the known reserves, and other oil and gas producers, like Anadarko and Alberta Energy (Non-Owner Producers), that have leased state or federal acreage with gas potential.

If the gas pipeline is a "contract carrier" as discussed above, the Committee understands that the Owner Producers will have a so-called "open season." During this period, potential shippers of gas are given the opportunity to enter long-term contracts with the pipeline owner, presumably on a fair and equitable basis. We were told that the reasons for an open season included demonstrating the need for a pipeline and providing information for sizing of the pipeline. If the Owner Producers own the pipeline, there is little need for an early open season since they have enough gas reserves themselves to justify construction of a pipeline and size it, assuming an adequate market exists. We

were also told that the open season must be conducted before an application is filed and that the FERC does not control the open season.

The Owner Producers have informed the state that they intend to conduct an open season as early as first quarter of this year, although production will not flow through the pipeline for about seven years. (More recently, in response to request for comments to the royalty-in-kind gas sale proposed by the Department of Natural Resources, the Owner Producers have suggested that an open season may be delayed.) Further, the Committee has told that the application process alone would likely take eighteen to twenty-four months to complete.

Allowing the Owner Producers to control the date for an open season and to require a binding commitment to ship gas so early in the process creates several problems for the state. First, the state will not be in a position to decide whether it wants to ship its gas by first quarter of this year. It will not even know whether it will be allowed to have midpoint deliveries to Alaska markets. Second, the Non-Owner Producers say that they will not be in a position to enter firm contracts so early in the process (without taking inordinate risk). If the Owner Producers sign twenty-year contracts for the full capacity of the line with themselves, then the state and the Non-Owner Producers would be effectively shut out.

It is in the Owner Producers' interest to shut their Non-Owner Producers out of the pipeline rendering the latter's leases valueless and forcing them to relinquish the leases to the state and the federal government. Ultimately, the Owner Producers could use their monopoly power to buy the leases cheaply from the state and federal government. Usually a pipeline company, which does not own the gas resource, conducts the open season. It has no motive to take advantage of other owners of the gas resource. That will not be the case here. Moreover, the Owner Producers, unlike a non-affiliated pipeline company, will have an incentive to create high tariffs. High tariffs reduce royalties and taxes, and create another formidable barrier to entry.

During the course of the Committee's hearings, we were also told that the FERC lacks the ability to control expansion of a pipeline. In other words, even assuming that expansion would be economic and would yield a reasonable return to the owners, the FERC cannot require it.

Initial Open Season

Here are some of the questions upon which we believe expert advice is needed. Is it true that the initial open season must be conducted before filing an application? Has the FERC ever considered an application before an open season? Is it true that the FERC has no control over the open season? Given the situation here, can the FERC delay the open season until later in the process? Would the state have the ability to block an early open season either before FERC or in court and on what basis would a challenge be most successful?

If the open season cannot be delayed, can the FERC stipulate that the original open season only requires an expression of interest rather than a binding commitment? Has the FERC ever issued such an order? If there are over-subscriptions, will space be pro-rated? What will be the method for pro-rationing, proven reserves, high bid, or some other method? Who will determine the duration of firm capacity obligations, the Owner Producers or the FERC? Will the length be 10, 15, or 20 years?

Expansion Open Season

Assuming that the Owner Producers effectively shut out the state or Non-Owner Producers from the initial open season, we have several questions regarding expansion of the pipeline. Does the FERC have the authority to mandate expansion for the benefit of the state or Non-Owner Producers over the Owner Producers' objection? If so, how would that be determined? Has FERC ever ordered expansion of a pipeline? Assuming that the pipeline were expanded, how would the tariff be determined? Would the parties seeking expansion only bear the incremental costs of the expansion? Would they have to bear part of the original costs? (ANGTA, unlike what we understand the FERC's general practice to be, allows the costs of a conditioning plant at Prudhoe Bay to be recovered from shippers. If Non-Owner Producers had to be build their own conditioning plant at their field, it would seem unfair to allow recovery of the Prudhoe Bay conditioning plant costs from them.) Assuming that the pipeline were expanded, how would access to the new capacity be allocated? Would the Owner Producers have the right of first refusal to the new capacity or would another open season be conducted?

JURISDICTION

Background

The Trans Alaska Pipeline System (TAPS) carries oil from the North Slope to Valdez. Along the route, some oil is delivered into intrastate commerce in the Fairbanks area for the Williams and Petro Star refineries and in Valdez upstream of the marine terminal for another Petro Star refinery. The oil delivered to the marine terminal is transferred to tankers for shipment primarily to lower 48 markets with an occasionally shipment to the Far East market.

The TAPS is operated as a "common carrier" pipeline, which must accept all oil tendered to it on an equal basis to all shippers. If there is insufficient capacity for the volumes tendered, the pipeline company apportions its available capacity to accommodate all shippers requesting capacity. The RCA and the FERC jointly regulate the TAPS. The RCA regulates the intrastate shipments, while the FERC regulates the interstate shipments.

Naturally, Alaskans want the North Slope gas, virtually all of which has been discovered to date is owned by the state, to be available for in-state demand just as North Slope oil is available for in-state demand. We were told during the hearings, however, that the

pipeline would not be a common carrier pipeline and that Alaska (and its regulatory agency, the RCA,) may have little say about the availability of gas for in-state demand.

In contrast to the TAPS situation, we were told at the hearing that, if "one molecule of gas" were shipped on a gas pipeline for interstate use, the pipeline would be exclusively regulated by the FERC. Even though the FERC would have exclusive jurisdiction, we were also told that the RCA would have general jurisdiction over "lateral lines" and that the RCA was "looking into these issues further."

The FERC representatives repeatedly answered their questions with reference to the Natural Gas Act (NGA), while barely mentioning the Alaska Natural Gas Transportation Act (ANGTA). Although the NGA does not talk about Alaska in-state use of North Slope gas, Section 13 of ANGTA clearly contemplates that North Slope gas transported along the Alaska Highway (Alcan) route to the lower 48 would be available for in-state use by Alaskans. With this background in mind, we have many questions regarding the respective agencies' jurisdiction and state access to North Slope gas for in-state demand.

State Access for In-State Demand and Tariffs

Assuming that the gas were to follow the Alcan route, where does the RCA's jurisdiction over lateral lines begin under the Natural Gas Act (NGA) and the Alaska Natural Gas Transportation Act (ANGTA)? Would the FERC or RCA decide whether mid-route delivery points could be established to serve Alaska markets such as Fairbanks, a spur line to Southcentral, and a spur line to Valdez? Under section 13 of the ANGTA, is an Alaskan mid-route delivery point required? Under either the NGA or ANGTA, could the FERC decide that the Alaska market would not be served, only the lower 48 market? If the pipeline owners opposed an Alaska mid-route delivery point, could the FERC mandate such a point? On what basis would FERC decide to allow a mid-route delivery point in Alaska at the time of the original construction of a pipeline? At a later date?

Can FERC guarantee now that Alaska will have access to **its own royalty gas**? If FERC cannot guarantee access to gas for Alaska under current law, what tweaking of federal law would you recommend to guarantee such access?

What would be the basis for in-state tariffs? Would there be a "postage stamp" tariff charging gas delivered to Fairbanks the same tariff as gas delivered to Chicago? Or would the tariff be determined on a mileage basis? According to Mofo, there was litigation regarding this issue in the late 1970's and the state's theory of a mileage-based tariff prevailed. Would that theory prevail under the NGA?

Regulation of In-State Tariffs and Prices

We were told that even if there were mid-route delivery points in Fairbanks, Delta Junction, and Tok, the RCA would not set tariff rates between the North Slope and those points in Alaska, rather the FERC would. Is this true under the Natural Gas Act (NGA)? Is it true under the ANGTA? What would be the basis for determining in-state tariffs on

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a pipeline with a Midwest final destination given that most of the costs would be incurred to serve the Midwest market?

Assuming that the tariff for shipment to Fairbanks is lower than the tariff for shipment to the Midwest, would the FERC set the price in Alaska for the gas? Would the state have the authority to set the price? How would the price in Fairbanks be determined?

Regulation over Hubs

We understand that the FERC does not regulate certain lengthy pipelines in the Gulf of Mexico that bring gas from the deep water to onshore pipelines. There the gas enters a "hub," a place where various pipelines meet. These lengthy pipelines may be thought of as gathering lines as opposed to transmission lines. In some respects an Alaska pipeline is akin to such gathering lines until it gets to a hub such as Fairbanks, where the gas could go to different markets. When the Committee asked questions about moving the jurisdiction of FERC to downstream of a Fairbanks hub, we got less than clear answers. Is it possible to move the FERC's jurisdiction downstream to a Fairbanks hub? In essence, is it possible to move the wellhead from Prudhoe Bay to Fairbanks? If it were not possible under existing law, what changes would you recommend so that the wellhead could be moved?

Regulation as a Common Carrier

As discussed above, the TAPS is a common carrier. We were told at the hearing that gas pipelines, unlike oil pipelines, are contract carriers. This means that a gas pipeline is not obligated to accept all gas tendered to it for transportation. In some respects, a gas pipeline through Alaska along the Alcan route would be more like the TAPS in that there is unlikely to be any competitor pipeline. Has the FERC ever regulated a gas pipeline as a common carrier pipeline? If so, what was the basis for the decision?

Regulation under the NGA or ANGTA

Under the ANGTA, a route for delivery of North Slope gas to the lower 48 has already been selected. That route is the Alcan route and it was selected ahead of an "Over the Top" route and a LNG route. Moreover, the Alcan route is the subject of a treaty and has already been approved by the Congress, the President and the Canadian government.

Given the ANGTA, what authority does the FERC have to consider a competing application for delivery of North Slope gas along an Alcan route under either the ANGTA or the NGA? Given the ANGTA, what authority does the FERC have to consider a competing application for delivery of North Slope gas along an Over the Top route under either the ANGTA or the NGA?

Under the NGA or the ANGTA, what authority will the state have with respect to environmental and right of way issues, including state-owned rights of way.

During the hearings the FERC staff stated that it couldn't even speculate about how long an application under the ANGTA would take to process. They could only say that it would not take any longer than a conventional NGA application. Since the whole purpose of the ANGTA is to expedite the certification and approval process, why can't FERC commit to a faster than conventional track for an ANGTA application?

Response To Request For Proposal
Answers to Questions on Attachment A

I. Upstream Access

A. General Discussion

The Legislature is correct in being concerned about the reality of "open access" on a pipeline owned either all, or in part, by the three largest owners of gas reserves on the North Slope – BP, Phillips, and Exxon. However, those same concerns exist whether or not BP, Phillips, and Exxon have an ownership interest in the pipeline. That is because BP, Phillips, and Exxon will be the anchor shippers. As such, whether or not they hold an ownership interest in the pipeline, they have an enormous amount of power and, therefore, control over (a) the structure and timing of an "open-season"; (b) the structure of the pipeline's tariff; and (c) the terms and conditions under which service will be provided to both the anchor shippers and others. They may also have a certain amount of control over the pipeline's potential expansion if not directly, indirectly through precedent agreements or undisclosed letter agreements.

1. Contract Carriers and the "Open Season": Natural gas pipelines are today somewhat of a hybrid between common carriers and contract carriers. Prior to the open access requirements imposed on virtually all federally-regulated interstate pipelines, interstate pipelines were true "contract carriers." They provided service to those with whom they chose to contract – service being provided pursuant to the rates and terms and conditions generally applicable to all similarly-situated shippers. These were usually set out in generally-available Rate Schedules. However, pipelines were also free to provide unique services tailored to a particular customer's needs -- so long as the pipeline obtained FERC approval prior to commencing service. These contracts were filed as separate "Rate Schedules." They were a part of the pipeline's filed tariff and, therefore, were public. They could become the basis for an undue discrimination claim down the road if the pipeline refused to provide similar rates or terms and conditions of service to a similarly-situated person requesting service. But, because pipelines were usually fully-contracted for on a firm basis, and because pro-rationing of service cannot be ordered under the Natural Gas Act, access was usually denied because of a lack of available firm capacity.

Some, but not all of this changed when FERC began to require interstate pipelines to provide "open access" transportation. Now, pipelines are still allowed to contract with whom they choose but there are new rules governing how

"excess" or "turned-back" capacity is to be made available. Rules have also been established to govern the means through which contracted-for but unneeded capacity can be temporarily released or permanently resold by the existing capacity holder. But, for pipeline expansions or new pipelines, until FERC developed its "open season" requirement there was no obligation to afford all potential shippers access to capacity on a non-discriminatory basis.

As the RFP observes, FERC has stated that the reasons for an open season include demonstrating a "need" for the pipeline and providing information regarding the "sizing" of the pipeline. These regulatory objectives are of little significance when dealing with an Alaskan natural gas pipeline. However, there is a more general objective also articulated by FERC -- to provide all potential shippers an equal opportunity to enter into long-term contracts with the pipeline. This latter objective, also, can be frustrated through advance negotiations, timing of the open season, or both.

Generally speaking, a new pipeline will hold an "open season" for all or some portion of its capacity. But, there are no specific rules or regulations governing the procedures for allocating generally-available pipeline capacity for new projects. Rather, there are only general guidelines and these guidelines – which have as their basis the NGA's nondiscrimination requirement – tend to reflect the complexities and risks associated with planning, financing, and developing new pipeline projects. Therefore, without rules governing how an open season should be conducted, an aggrieved shipper must wait until after the capacity has been awarded and the certificate has been filed before it can raise an objection.

The "need" for the Alaskan pipeline, it would seem, should be measured by reference to the projected need for additional natural gas in both Alaska and the Lower-48 – not by the willingness of BP, Phillips, and Exxon to contract with the pipeline. Similarly, the proper sizing of the pipeline should be determined by reference to the delivery potential of reserves along the route of the pipeline or accessible to the pipeline (as is done in the OCS) not by reference to the reserves that BP, Phillips, and Exxon are willing to commit to the pipeline. Of course, the viability of the pipeline is in large part, dependent upon the receipt of long-term contractual commitments from BP, Phillips, or ExxonMobil. The ultimate question then, is whether these producers either need to, or can be required to, produce these gas reserves. Alternatively, can they be enticed into producing their reserves? But, if one allows the "need" for this pipeline or its sizing to be controlled exclusively by the outcome of the open season, FERC would be abdicating its regulatory responsibility to BP, ExxonMobil, and Phillips. Therefore, in this case, it would not be beyond the pale for FERC to indicate that it will move

forward and process an application for an Alaska pipeline on the basis of overall national need – not on the basis of executed binding precedent agreements. This could be done as a matter of policy to eliminate or mitigate the significant power that these producers currently hold over the terms and conditions of service on an Alaskan pipeline. FERC could at the same time, indicate when the pipeline should hold its open season and the terms and conditions under which that open season will be conducted. This would have to be done by a new rulemaking.

B. Initial Open Season – Response to Specific Questions

1. Although FERC prefers that an open season be held prior to the filing of a certificate application it is not required. Open seasons have been held before and after the filing of certificate applications. And, in some cases, the open season has been held after the certificate has issued. In situations where the open season is held either after the application is filed or after the certificate has issued, it is usually because pre-subscriptions of capacity are already sufficient to justify the pipeline. On new projects, FERC has allowed a significant amount of capacity to be pre-subscribed – and not even made subject to the outcome of the open season – generally where owner-shippers have significant reserves to ship and have committed a significant amount of capital to the project. For example, in Green Canyon Pipe Line Co., 47 FERC ¶ 61,310 (1989), 78% of the pipeline's capacity was pre-subscribed with only 22% made available through an open season. FERC has not been sympathetic to protests raised by potential shippers which were not prepared to commit to capacity at the time of the open season. Shell Gas Pipeline Co., 74 FERC ¶ 61,219 (1997).

2. It is not true that FERC has no control over the open season. It is true that FERC has yet to exercise control over the open season except on an after-the-fact basis when faced with complaints of undue discrimination or preference. We believe that it is well within FERC's authority to promulgate rules of a general or specific nature governing open seasons.

3. We do not believe that the state could block the project sponsors from conducting an early open season either by filing a complaint before FERC or by seeking relief in the courts. Given the existing statutory and regulatory scheme under which FERC operates, any such challenge would be deemed premature and dismissed by FERC; and any attempt to seek judicial review of a FERC decision declining to entertain such a complaint would fail the ripeness standard. Further, because exclusive jurisdiction over appeals from FERC action resides in the Courts of Appeals, there is no jurisdiction in the United States District Courts. As such,

under the existing regulatory scheme, a challenge at FERC would have to await the filing of a certificate application reflecting the allocation of capacity from the open season, and any challenge to FERC's ruling would have to await a final decision on the merits before an appeal could be brought in a United States Court of Appeals.

If the Legislature were to conclude that it is essential to have this issue addressed before an application is filed, the best option is to seek a rulemaking at FERC governing the timing of and rules for conducting an open season for the Alaska pipeline. Although FERC has no obligation to respond affirmatively to such a request, we believe that if the filing is preceded by meetings with FERC Staff and the FERC Commissioners to explain the basis for concern, the Legislature will have a receptive audience. At the same time, the state could consider a federal legislative directive to FERC to promulgate rules regarding the timing and content of any open season for an Alaskan pipeline, including guidelines on how capacity is to be allocated.

4. If an open season is held and an application is filed based on the results of that open season, FERC could rule, in response to a complaint, that given the long lead time between the filing of the application and the proposed in-service date of the pipeline that a second open season should be held to confirm or reallocate capacity. That second open season would have to take place within some specified time prior to the commencement of construction because, as a practical matter, financing must be in place prior to the commencement of construction and financing will be dependent upon the pipeline's contracts. FERC could also make this determination as a part of a rulemaking regarding the Alaskan pipeline project were a petition for a rulemaking filed. The arguments would have to be persuasively made – as we believe they could – because FERC has never recharacterized as an "expression of interest" an open season that the pipeline considered "binding" and based upon which it entered into "binding" precedent agreements. Keeping in mind that under the Natural Gas Act a pipeline is free to enter into binding contractual commitments, FERC will have to make the finding that those commitments are contrary to the public interest and require modification.

5. In a properly-conducted open season, an over-subscription means that there are qualifying bids for more capacity than has been <u>offered</u> in the open season, keeping in mind that certain capacity may be pre-subscribed and, therefore, not offered. Capacity is generally allocated based upon the highest net present value ("npv") to the pipeline (typically, the discounted cash flow of incremental revenue per dekatherm based on factors such as rate, term, quantity, reserve commitment, and date on which service is to commence). <u>E.g.</u>, <u>Nautilus</u>

Pipeline Co., LLC, 78 FERC ¶ 61,325 (1997); Southern Natural Gas Co., 96 FERC ¶ 61,008 (2001); Tennessee Gas Pipeline Company, 76 FERC ¶ 61,101 (1996); Texas Eastern Transmission Corp., 79 FERC ¶ 61,258, order on reh'g, 80 FERC ¶ 61,270 (1997). Only capacity for which there is a tie tends to be pro-rated, although using pro-rationing as the method for breaking the tie is not required. E.g., Kern River Gas Transmission Co., 95 FERC ¶ 61,022 (2001); Transcontinental Gas Pipe Line Corp., 66 FERC ¶ 61,273 (1994); Green Canyon Pipe Line Co., 47 FERC ¶ 61,310 (1989); Shell Gas Pipeline Co., 76 FERC ¶ 61,260 (1986). The only real rule is that the criteria used to allocate capacity must be applied without undue discrimination. Id.

6. The pipeline may establish a minimum term for contracts for newly constructed facilities National Fuel Gas Supply Corporation, 77 FERC ¶ 61,005 (1996), as well as a maximum term. Southern Natural Gas Company, 96 FERC ¶ 61,008 (2001). There is no FERC policy on the duration of contracts – they may be for the life of the reserves.

C. **Expansion Open Season – Response to Questions**

1. FERC has absolutely no authority to mandate an expansion of the pipeline under existing law and any attempt by FERC to condition a certificate on a requirement that expansion capacity be constructed would be challenged as ultra vires. Panhandle Eastern Pipe Line Co. v. FERC, 204 F.2d 675 (3d Cir. 1953). To the best of our knowledge, FERC has never successfully ordered the expansion of a pipeline under the Natural Gas Act. (FERC does possess that power, in certain circumstances, under the Outer Continental Shelf Lands Act although, to the best of our knowledge, it has not used that authority).

2. Pipeline expansions are treated in much the same way by FERC as are new pipelines. Rates are usually designed on an incremental basis to ensure that customers bear only those costs associated with the facilities that they use. Of course, an expansion customer may benefit from the original capacity, depending on the operational characteristics of the pipeline. In a case where a pipeline expansion is to be used by the original shippers and where the expansion shippers also utilize the original capacity the costs of the expansion may be rolled into the original cost and allocated among all shippers.

3. Access to new capacity would be handled consistently with the tariff of the existing pipeline or in accordance with the same rules discussed above for new pipelines. Some pipelines have included in their tariffs specific procedures

to be followed for purposes of allocating expansion capacity. When this is done, and the tariff is approved by FERC, the pipeline need only follow its tariff rules when allocating capacity.

4. The Commission strongly encourages, and, in fact, expects that an open season will be held for all new capacity, including expansion capacity. Again, in the absence of a tariff provision stating otherwise, pre-subscriptions are permitted if the facts and circumstances so require. The Legislature should be aware that bids can be submitted in the initial open season for both initial capacity and expansion capacity if the open season is so structured. Rights-of-first-refusal ("ROFR") relate to the right of an existing shipper to continue its existing service upon contract expiration by matching the highest competitive bid for service up to the maximum rate. Under FERC's Order No. 637 certain restrictions apply to the ROFR but, to respond to the state's question, these rights do not extend to new capacity.

II. Jurisdiction

A. General Discussion

A primary distinction between natural gas pipelines subject to FERC's jurisdiction under the NGA and oil pipelines subject to FERC's jurisdiction under the ICA is that oil pipelines are common carriers while gas pipelines are not. In addition, the commingling of interstate gas with intrastate gas in a common stream causes the entire gas stream to fall within the exclusive jurisdiction of FERC under the NGA as being "in interstate commerce." However, the sale of natural gas to communities or distribution companies in Alaska is not within FERC's jurisdiction even though the gas travels in a commingled stream through an interstate pipeline. As such, the availability of the Alaskan gas for in-state use is not affected, other than in instances of pipeline operational problems or capacity restraints. The terms and conditions of the transportation service, however, will be within the province of FERC (including those relating to capacity curtailments). State agencies can regulate wholly intrastate facilities or facilities which form part of an intrastate natural gas company even if natural gas is received from an interstate pipeline. This can be done by having the natural gas transported through the interstate pipeline under NGPA section 311(a)(1) to the point of interconnect with the intrastate facilities or by transporting the gas through the interstate pipeline under NGA § 7, thereby transforming the intrastate system into a Hinshaw pipeline which is exempt from FERC's jurisdiction under NGA section 1(c). In the latter case it would be essential that the RCA exercise regulatory control over the intrastate

facilities and that the gas be consumed within Alaska. With that as background I will respond to the specific questions asked, to the extent possible.

B. State Access for In-State Demand and Tariffs – Response to Specific Questions

1. The RCA's jurisdiction over lateral lines exists wherever there are intrastate facilities owned and operated by an Alaskan company which are used to sell or deliver gas, whether bundled or unbundled, to customers in Alaska (whether wholesale or retail). Under the Natural Gas Act, federal jurisdiction ends at the local distribution of gas (NGA § 1(b)) or at the point of interconnect between an interstate transmission system and an intrastate transmission system where all of the gas received by the intrastate system is consumed within the state and the rates and services of the intrastate system are subject to regulation by a state commission. NGA § 1(c), 15 U.S.C. § 717(c).

2. Assuming that the pipeline which is ultimately constructed is the pipeline which was authorized under ANGTA, FERC would have the authority to order mid-route delivery points in Alaska were the pipeline to refuse to provide the requested delivery points. Under Section 13 of ANGTA, in the exercise of that authority, FERC is required to ensure that the State of Alaska may ship its royalty gas for use within Alaska "and is to issue whatever authorizations are necessary to withdraw such gas from the interstate market for use within Alaska." (Note: The language of ANGTA pre-dates the Wellhead Decontrol Act and, therefore, speaks in terms of withdrawing gas from the interstate market. Before the decontrol of wellhead sales of natural gas, once the sale of gas in interstate commerce commenced or the transportation of natural gas in interstate commerce commenced, the entire gas stream became dedicated to the interstate market and could not be withdrawn from that market for intrastate purposes. That is no longer the law. Natural gas from a single wellhead may now be sold in both the interstate and intrastate markets. There is no longer a concern about "withdrawing" gas from the interstate market because gas is no longer "dedicated" to the interstate market. Rather, contracts will control the destination of gas.) However, if the pipeline is not constructed under the authority of ANGTA, but only under the NGA, then the State of Alaska would have to file a complaint against the pipeline were it to refuse to allow the required intrastate delivery points and/or the required interconnection with intrastate facilities. The Complaint would have to be based on the prohibition in NGA § § 4 and 5 against undue discrimination and undue preference.

3. Given the language of Section 13 of ANGTA, the State of Alaska is "authorized" to ship its royalty gas on the approved Alaskan pipeline system but the statute does not specify under what "terms and conditions" or whether access is guaranteed for the State's royalty gas. While the clear inference is that Congress intended all shippers to have "access" the statutory language does not go that far. On this point as well as the issue in II E., infra, additional research is required. However, if an Alaskan pipeline is constructed solely under the authority of the Natural Gas Act – without reference to ANGTA – then the State of Alaska, clearly, would have to participate in the open season in the same way as a private party.

4. If one were to conclude that under ANGTA FERC can guaranty access to the state's royalty gas, then the Legislature's primary concern should be whether a pipeline can be approved outside of ANGTA. There are those (including DOE and FERC) who believe that current law does not require that a pipeline constructed to bring North Slope Alaskan gas to the Lower 48 must be the pipeline authorized under ANGTA. Rather, they believe that such a pipeline could be authorized solely under the NGA. As explained in response to E. below, we are unable, without additional research, to opine as to the correctness of that position. Regardless of the answer to that question, and given the view of the DOE and FERC, it would be best to ensure transportation capacity rights for the state's royalty gas in any new legislation directed at the Alaska natural gas pipeline.

5. In-state tariffs would related only to intrastate facilities and, therefore, would be governed exclusively by Alaskan law.

6. FERC-approved rates – which would apply to deliveries made within the State of Alaska or in interstate commerce – would be governed by federal law. Under current FERC policy rates are to reflect distance absent other overriding factors. 18 C.F.R. § 284.10(a)(3) (2001). The Commission has concluded that on most pipeline systems, the costs of providing service are materially affected by the distance the gas is transported. E.g., Northwest Pipeline Corp., 82 FERC ¶ 61,158 (1998); Kern River Gas Transmission Co., (ALJ: 94 FERC ¶ 63,008 (2001)). However, the Commission does not mandate mileage-based rates. For example, on some systems distance may not materially affect the cost of doing business – the most common factor in determining whether the permit postage-stamp rates is whether the pipeline received gas at both ends of its system so that the gas may flow in either direction, rather than in a single upstream to downstream direction. Northwest Pipeline Corp., 82 FERC ¶ 61,158 (1998); East Tennessee Natural Gas Co., 64 FERC ¶ 61,159 (1993); Williams Natural Gas Co., 41 FERC ¶ 61,037 (1987), Southern Natural Gas Co., 10 FERC ¶ 61,287 (1980).

In addition, the Legislature should be aware that FERC allows negotiated rates which may differ significantly from tariff rates.

C. **Regulation of In-State Tariffs and Prices**

1. It is true, as noted above, that even if there were mid-route delivery points in Alaska, FERC would set the rates for that transportation service. This is because, due to the commingling rule, all of the gas in question is treated as gas being transported interstate commerce placing exclusive jurisdiction over the rates for such transportation service in FERC. NGA § 1(b). ANGTA does not alter this regulatory scheme. In fact, ANGTA Section 13 preserves FERC's jurisdiction over rates stating that "the . . . [FERC] shall issue all authorizations necessary to effectuate such shipment and withdrawal subject to review by the Commission only of the justness and reasonableness of the rates charges for such transportation."

2. If distance-based rates were structured for the Alaskan pipeline, more costs would be allocated to shippers designating delivery points in the Midwest over shippers designating Fairbanks.

3. FERC has no jurisdiction over the price at which natural gas can be sold in Alaska. The state would have the authority to set the price for such sales. And, presumably, the price in Fairbanks would be a delivered price inclusive of the cost of the gas, the interstate transportation costs, and any intrastate transportation costs.

4. It is unlikely that FERC would disclaim jurisdiction over the transportation of natural gas from the North Slope to Fairbanks. While the unusual length of pipeline bringing natural gas from the wellhead to the "hub" is similar to the long, deepwater gathering lines in the Gulf of Mexico, both in concept and in purpose – bringing natural gas from a wellhead located a significant distance from a possible point of interconnection on the interstate pipeline grid –here there is only one continuous pipeline which will extend from the North Slope to natural gas markets. This configuration is indicative of an interstate pipeline, not a gathering system. In fact, we would conclude that were a pipeline comparable to that proposed for Alaska to be constructed in the Gulf of Mexico, the entire pipeline would be classified by FERC as an interstate pipeline subject to the Commission's NGA jurisdiction.

5. While I do not believe that FERC would be inclined to disclaim jurisdiction over the portion of the Alaska pipeline extending from the North Slope

to Fairbanks if there is only one pipeline under common ownership which will take the North Slope gas to market, such a determination might be obtained if there were two separate entities (potentially even with the same ownership) and a bifurcated line – that is, Company A owning the line (and, ideally it will pick up more than just North Slope gas) from the North Slope to Fairbanks, and Company B owning the line from Fairbanks south. It may also be possible – albeit somewhat difficult – to obtain authorization from FERC for a "dual-use" facility. Under this scenario, the state would lease an undivided interest in the pipeline facilities to Fairbanks for the state's royalty gas and obtain a ruling from FERC that the leased capacity is subject only to state regulation. While FERC has in some instance, allowed the converse, policy considerations here could play a significant role in attempting to expand that authorization. Any of these approaches would require the full cooperation of the pipeline owners and appropriate rulings from FERC.

6. As noted above, capacity reservations for the state's royalty gas and state control over that capacity is potentially achievable under existing law through the arrangements discussed above. However, an amendment to ANGTA to ensure state control over the capacity used to transport the state's royalty gas would be the best solution, as would, of course, explicit language in any new federal legislation.

D. Regulation as a Common Carrier – Response to Specific Questions

1. There appears to be no question that there will be only one major gas pipeline transporting North Slope gas to the Lower 48. However, that does not alter the fact that under existing law, including both ANGTA and the NGA, such a pipeline is not a common carrier. Legislation would be required to alter that status and it is my understanding that the United States Congress would not support such legislation. Legislation addressing competition issues related to access, however, may well to receive such support.

2. Neither FERC nor its predecessor has ever regulated a natural gas pipeline as a common carrier. To do so would be outside the scope of the agency's authority under its enabling acts.

E. Regulation Under the NGA or ANGTA – Response to Specific Questions

1. The issue of FERC's authority to approve an application for delivery of North Slope gas along a route different from that authorized under ANGTA is subsumed into the question whether ANGTA precludes FERC from considering an application filed exclusively under the NGA for an Alaskan natural gas pipeline intending to deliver natural gas from the North Slope of Alaska to the Lower 48. I am aware that competent counsel (both public and private) have differing views on this critical issue. I am also aware that DOE and FERC are of the view that FERC may consider and approve under its Natural Gas Act authority a competing application which proposes a route other than the Alcan route.

As I mentioned above, I do not know the answer to these questions at this time. Additional research and analysis is required. Of course, Congress could render that issue moot through legislation such as S. 1766.

2. The state's authority regarding environmental issues and rights-of-way, including rights-of-way through state-owned lands, continues, intact, with the caveat that the state cannot refuse to grant the necessary rights-of-way nor can it interfere in the construction of a federally-approved project along a federally-approved route. However, FERC has historically listened to legitimate state concerns and can be expected to continue to do so, conditioning certificates accordingly. But, in the end, FERC's decision will control.

3. FERC cannot now commit to a faster track for approval of a project because it has not seen the application and does not know how extensive an environmental review it will be required to conduct. FERC has stated publicly that the existing environmental data for ANGTS is stale and that updated studies and analysis must be filed and reviewed, even for the existing route. The time that will be required to conduct that review will depend, on large part, on how complete the data are and how much opposition the project receives. Absent a statutory mandate to complete the review within a specified time, FERC simply will not commit to any particular timeframe within which it will grant a certificate.

ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

Official Business

Senator John Torgerson, Chair
Senator Rick Halford
Senator Pete Kelly
Senator Johnny Ellis

Representative Joe Green, Vice-Chair
Representative Brian Porter
Representative Scott Ogan
Representative John Davies

To: Joint Committee on Natural Gas Pipelines

From: Senator Torgerson, Chair
Joint Committee on Natural Gas Pipelines

Date: February 15, 2002

Subject: Attachment to Committee Meeting Folders for 2/15/02

The United States Senate is no longer considering SB 1766, the Energy Policy Act of 2002, and is now considering S. 1948. Enclosed please find the pages pertinent to the Alaska Natural Gas Pipeline that we received on February 14, 2002.

Session: January – May
State Capitol, #427
Juneau, AK 99801
Phone: 907-465-2828
Fax: 907-465-4779

Interim: May – December
35477 Kenai Spur Hwy., Suite 101A
Soldotna, AK 99669
Phone: 907-260-3041
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New Federal legislation
2/14/02

TITLE VII – NATURAL GAS PIPELINES

Subtitle A – Alaska Natural Gas Pipeline

SEC. 701. SHORT TITLE.

This subtitle may be cited as the "Alaska Natural Gas Pipeline Act of 2002".

SEC. 702. FINDINGS.

The Congress finds that:

(1) Construction of a natural gas pipeline system from the Alaskan North Slope to United States markets is in the national interest and will enhance national energy security by providing access to the significant gas reserves in Alaska needed to meet the anticipated demand for natural gas.

(2) The Commission issued a certificate of public convenience and necessity for the Alaska Natural Gas Transportation System, which remains in effect.

SEC. 703. PURPOSES.

The purposes of this subtitle are–

(1) to expedite the approval, construction, and initial operation of one or more transportation systems for the delivery of Alaska natural gas to the contiguous United States;

(2) to ensure access to such transportation systems on an equal and nondiscriminatory basis and to promote competition in the exploration, development and

production of Alaska natural gas; and

(3) to provide federal financial assistance to any transportation system for the transport of Alaska natural gas to the contiguous United States, for which an application for a certificate of public convenience and necessity is filed with the Commission not later than 6 months after the date of enactment of this subtitle.

SEC. 704. ISSUANCE OF CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY.

(a) AUTHORITY OF THE COMMISSION.– Notwithstanding the provisions of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719-719*o*), the Commission may, pursuant to section 7(c) of the Natural Gas Act (15 U.S.C. 717f(c)), consider and act on an application for the issuance of a certificate of public convenience and necessity authorizing the construction and operation of an Alaska natural gas transportation project other than the Alaska Natural Gas Transportation System.

(b) ISSUANCE OF CERTIFICATE.–

(1) The Commission shall issue a certificate of public convenience and necessity authorizing the construction and operation of an Alaska natural gas transportation project under this section if the applicant has–

(A) entered into a contract to transport Alaska natural gas through the proposed Alaska natural gas transportation project for use in the contiguous United States; and

(B) satisfied the requirements of section 7(e) of the Natural Gas Act (15

U.S.C. 717f(e)).

(2) In considering an application under this section, the Commission shall presume that–

(A) a public need exists to construct and operate the proposed Alaska natural gas transportation project; and

(B) sufficient downstream capacity will exist to transport the Alaska natural gas moving through such project to markets in the contiguous United tates.

(c) EXPEDITED APPROVAL PROCESS.– The Commission shall issue a final order granting or denying any application for a certificate of public and convenience and necessity under section 7(c) of the Natural Gas Act (15 U.S.C. 717f(c)) and this section not more than 60 days after the issuance of the final environmental impact statement for that project pursuant to section 704.

(d) REVIEWS AND ACTIONS OF OTHER FEDERAL AGENCIES.– All reviews conducted and actions taken by any federal officer or agency relating to an Alaska natural gas transportation project authorized under this section shall be expedited, in a manner consistent with completion of the necessary reviews and approvals by the deadlines set forth in this subtitle.

(e) REGULATIONS.– The Commission may issue regulations to carry out the provisions of this section.

SEC. 705. ENVIRONMENTAL REVIEWS.

(a) COMPLIANCE WITH NEPA.– The issuance of a certificate of public convenience and necessity authorizing the construction and operation of any Alaska natural gas transportation

project under section 704 shall be treated as a major federal action significantly affecting the quality of the human environment within the meaning of section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)).

(b) DESIGNATION OF LEAD AGENCY.– The Commission shall be the lead agency for purposes of complying with the National Environmental Policy Act of 1969, and shall be responsible for preparing the statement required by section 102(2)(c) of that Act (42 U.S.C. 4332(2)(c)) with respect to an Alaska natural gas transportation project under section 704. The Commission shall prepare a single environmental statement under this section, which shall consolidate the environmental reviews of all Federal agencies considering any aspect of the project.

(c) OTHER AGENCIES.– All Federal agencies considering aspects of the construction and operation of an Alaska natural gas transportation project section 704 shall cooperate with the Commission, and shall comply with deadlines established by the Commission in the preparation of the statement under this section. The statement prepared under this section shall be used by all such agencies to satisfy their responsibilities under section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)) with respect to such project.

(d) EXPEDITED PROCESS.– The Commission shall issue a draft statement under this section not later than 12 months after the Commission determines the application to be complete and shall issue the final statement not later than 6 months after the Commission issues the draft statement, unless the Commission for good cause finds that additional time is needed.

(e) UPDATED ENVIRONMENTAL REVIEWS UNDER ANGTA.– The Secretary of

Energy shall require the sponsor of the Alaska Natural Gas Transportation System to submit such updated environmental data, reports, permits, and impact analyses as the Secretary determines are necessary to develop detailed terms, conditions, and compliance plans required by section 5 of the President's Decision.

SEC. 706. FEDERAL COORDINATOR.

(a) ESTABLISHMENT.– There is established as an independent establishment in the executive branch, the Office of the Federal Coordinator for Alaska Natural Gas Transportation Projects.

(b) THE FEDERAL COORDINATOR.– The Office shall be headed by a Federal Coordinator for Alaska Natural Gas Transportation Projects, who shall–

(1) be appointed by the President, by and with the advice of the Senate,

(2) hold office at the pleasure of the President, and

(3) be compensated at the rate prescribed for level III of the Executive Schedule (5 U.S.C. 5314).

(c) DUTIES.– The Federal Coordinator shall be responsible for–

(1) coordinating the expeditious discharge of all activities by federal agencies with respect to an Alaska natural gas transportation project; and

(2) ensuring the compliance of Federal agencies with the provisions of this subtitle.

SEC. 707. JUDICIAL REVIEW.

(a) EXCLUSIVE JURISDICTION.– The United States Court of Appeals for the District of

Columbia Circuit shall have exclusive jurisdiction to determine–

(1) the validity of any final order or action (including a failure to act) of the Commission under this subtitle;

(2) the constitutionality of any provision of this subtitle, or any decision made or action taken thereunder; or

(3) the adequacy of any environmental impact statement prepared under the National Environmental Policy Act of 1969 with respect to any action under this subtitle.

(b) DEADLINE FOR FILING CLAIM.– Claims arising under this subtitle may be brought not later than 60 days after the date of the decision or action giving rise to the claim.

SEC. 708. LOAN GUARANTEE.

(a) AUTHORITY.– The Secretary of Energy may guarantee not more than 80 percent of the principal of any loan made to the holder of a certificate of public convenience and necessity issued under section 704(b) of this Act or section 9 of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719g) for the purpose of constructing an Alaska natural gas transportation project.

(b) CONDITIONS.–

(1) The Secretary of Energy may not guarantee a loan under this section unless the guarantee has filed an application for a certificate of public convenience and necessity under section 704(b) of this Act or for an amended certificate under section 9 of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719g) with the Commission not later than 6 months after the date of enactment of this subtitle.

(2) A loan guaranteed under this section shall be made by a financial institution subject to the examination of the Secretary.

(3) Loan requirements, including term, maximum size, collateral requirements and other features shall be determined by the Secretary.

(c) LIMITATION ON AMOUNT.– Commitments to guarantee loans may be made by the Secretary of Energy only to the extent that the total loan principal, any part of which is guaranteed, will not exceed $10,000 000,000.

(d) REGULATIONS.– The Secretary of Energy may issue regulations to carry out the provisions of this section.

(e) AUTHORIZATION OF APPROPRIATIONS.– There are authorized to be appropriated to the Secretary such sums as may be necessary to cover the cost of loan guarantees, as defined by section 502(5) of the Federal Credit Reform Act of 1990 (2 U.S.C. 661a(5)).

SEC. 709. STUDY OF ALTERNATIVE MEANS OF CONSTRUCTION.

(a) REQUIREMENT OF STUDY.– If no application for the issuance of a certificate of public convenience and necessity authorizing the construction and operation of an Alaska natural gas transportation project has been filed with the Commission within 6 months after the date of enactment of this title, the Secretary of Energy shall conduct a study of alternative approaches to the construction and operation of the project.

(b) SCOPE OF STUDY.– The study shall consider the feasibility of establishing a government corporation to construct an Alaska natural gas transportation project, and alternative means of providing federal financing and ownership (including alternative combinations of

government and private corporate ownership) of the project.

(c) CONSULTATION.– In conducting the study, the Secretary of Energy shall consult with the Secretary of the Treasury and the Secretary of the Army (acting through the Commanding General of the Corps of Engineers).

(d) REPORT.– If the Secretary of Energy is required to conduct a study under subsection (a), he shall submit a report containing the results of the study, his recommendations, and any proposals for legislation to implement his recommendations to the Congress within 6 months after the expiration of the Secretary of Energy's authority to guarantee a loan under section 708.

SEC. 710. SAVINGS CLAUSE.

Nothing in this subtitle affects any decision, certificate, permit, right-of-way, lease, or other authorization issued under section 9 of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719g).

SEC. 711. CLARIFICATION OF AUTHORITY TO AMEND TERMS AND CONDITIONS TO MEET CURRENT PROJECT REQUIREMENTS.

Any Federal officer or agency responsible for granting or issuing any certificate, permit, right-of-way, lease, or other authorization under section 9 of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719g) may add to, amend, or abrogate any term or condition included in such certificate, permit, right-of-way, lease, or other authorization to meet current project requirements (including the physical design, facilities, and tariff specifications), so long as such action does not compel a change in the basic nature and general route of the Alaska Natural Gas Transportation System as designated and described in section 2 of the President's

Decision, or would otherwise prevent or impair in any significant respect the expeditious construction and initial operation of such transportation system.

SEC. 712. DEFINITIONS.

For purposes of this subtitle:

(1) The term "Alaska natural gas" has the meaning given such term by section 4(1) of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719b(1)).

(2) The term "Alaska natural gas transportation project" means any other natural gas pipeline system that carries Alaska natural gas from the North Slope of Alaska to the border between Alaska and Canada (including related facilities subject to the jurisdiction of the Commission) that is authorized under either–

(A) the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719-719*o*); or

(B) section 704 of this subtitle.

(3) The term "Alaska Natural Gas Transportation System" means the Alaska natural gas transportation project authorized under the Alaska Natural Gas Transportation Act of 1976 and designated and described in section 2 of the President's Decision.

(4) The term "Commission" means the Federal Energy Regulatory Commission.

(5) The term "natural gas company" means a person engaged in the transportation of natural gas in interstate commerce or the sale in interstate commerce of such gas for resale; and

(6) The term "President's Decision" means the Decision and Report to Congress on the Alaska Natural Gas Transportation system issued by the President on September 22, 1977

pursuant to section 7 of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719c) and approved by Public Law 95-158.

SEC. 713. SENSE OF THE SENATE.

It is the sense of the Senate that an Alaska natural gas transportation project will provide significant economic benefits to the United States and Canada. In order to maximize those benefits, the Senate urges the sponsors of the pipeline project to make every effort to use steel that is manufactured or produced in North America and to negotiate a project labor agreement to expedite construction of the pipeline.

(b) A waiver, reduction, or deferral of tax made by the commissioner under (a) of this section is not effective until approved by the legislature. The legislature may approve a waiver, reduction, or deferral of tax under this section only by enacting legislation.

*** Sec. 11.** AS 46.40.094 is amended by adding a new subsection to read:

(d) Notwithstanding any other provision of this section, for a natural gas pipeline project from the Alaska North Slope following a route that parallels the Trans Alaska Pipeline System and the Alaska Highway to the Canadian border or a route that runs south to Alaska tidewater for which the project applicant has complied with AS 38.35.240 and obtained all certificates described in that section, any agency responsible for the consistency determination with respect to proposed uses or activities involved in the project may, in its discretion, conduct the review and make the consistency determination in separate phases in a manner that promotes review of proposed uses and activities based upon the project's design, construction sequence, and schedule.

*** Sec. 12.** The uncodified law of the State of Alaska is amended by adding a new section to read:

LIMITATION OF CERTAIN ACTIONS. A legal proceeding may not be initiated to challenge the constitutionality of sec. 2 of this Act or the constitutionality of AS 38.35.235 - 38.35.259, added by sec. 5 of this Act, more than 60 days after the effective date of this Act.

*** Sec. 13.** The uncodified law of the State of Alaska is amended by adding a new section to read:

LEGISLATIVE AUTHORIZATION AND APPROVAL. AS 42.40.695, added by sec. 9 of this Act, and this section constitute the approval required by AS 42.40.285 for the issuance of the bonds described in AS 42.40.695.

*** Sec. 14.** This Act takes effect immediately under AS 01.10.070(c).



State Financial Participation in an Alaska Natural Gas Pipeline

- **The History**
- **The Project**
- **The Options**
- **The Costs**
- **The Risks of State Participation**

Prepared by the Alaska Department of Revenue
January 31, 2002

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CH2M HILL

STATE OF ALASKA

Department of Revenue

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January 31, 2002

The Honorable Tony Knowles
Governor of Alaska

The Honorable Rick Halford
Senate President
Alaska State Legislature

The Honorable Brian Porter
Speaker of the House
Alaska State Legislature

The Honorable John Torgerson
Chairman, Joint Natural Gas Pipelines Committee
Alaska State Legislature

Dear Governor Knowles, President Halford, Speaker Porter and Senator Torgerson:

It has been six months since Senate Bill 158 was signed into law, calling on the Department of Revenue to prepare a report on the merits of state ownership or financing of an Alaska Gas Pipeline project. In those six months my staff, our consultants and I have spent considerable hours looking for the light at the end of the pipeline. We had hoped that light would lead us to clear and convincing answers to the questions: Should the state invest in a natural gas pipeline? If so, where would the state get the money? Are the rewards worth the risks? Would state financial participation in the project help bring about the start of construction?

Although we have reached the end of our assignment, we did not find answers to every question. It was like finding the light at the end of the line, only to discover that you don't have the authority to turn the switch on and off. Although we believe the financial risks to the state are substantial, it is possible that some would decide—as a matter of public policy—that the state should take such sizable risks in an attempt to exercise greater control over its own destiny.

As for finding the money for state participation in a project, Alaska is a little short on cash these days—unless you go into the Permanent Fund, which presents several legal and political constraints. Clearly, one answer is that state participation perhaps could be a plus if the state could issue tax-exempt bonds to help finance the multibillion-dollar project. But that switch is in federal hands.

We believe our report sheds new light on old discussions, and serves as a reference book on the project. Our work includes:

- A comprehensive review of the history of Alaska gasline proposals.
- A summary of current gasline proposals and potential sponsors.
- An analysis of the issues of state financial participation—how much money would be needed, and where could it come from.
- An explanation of what could or could not work for state financing—and why not.
- And what are the risks of putting up state money.

I believe our report provides you—and the Alaska public—with the information needed to make informed decisions.

In closing, I would like to thank our two consultants on this report: Dave Gray of CH2M Hill and Bill Garner of Petrie Parkman & Co. Mr. Gray is director of energy economics for CH2M HILL's Bellevue, Washington, office, and Mr. Garner is in the Houston office of Petrie Parkman, an investment banking firm that specializes in oil and gas issues. Their technical assistance was key to the success of this report.

As you read through this report, please call on the department for any additional information you need. I look forward to working with you on this project, which is so important to Alaska's future.

Sincerely,

Wilson L. Condon
Commissioner

Executive Summary

The purpose of this report is to examine whether the State of Alaska should financially participate in a pipeline to transport natural gas from Alaska's North Slope to domestic or foreign markets.

The legal and fiscal issues today are not much different than the gas pipeline concerns Alaskans have grappled with over the past 30 years. During that time, the state and private groups commissioned several reports both favoring and dissuading state financial participation. Although the issues have not changed much, certainly the legal, regulatory, market and fiscal situation today is much different than that of decades ago.

Today, proponents of state involvement cite three main reasons for the state to participate in ownership or financing of an Alaska Gas Pipeline project:

- It would be a good investment with a healthy rate of return and minimal risk.
- Alaska should control its own financial destiny and development of its resources.
- State involvement would enhance the project's feasibility—that is, the pipeline would stand a better chance of getting built sooner if the state was a financial partner.

The answers, however, are much less clear than the questions.

A Good Investment

The state is in a precarious financial position as it starts 2002. Its ability to provide essential services will be tested as the Constitutional Budget Reserve Fund runs out of money. The Department of Revenue projects that the reserve fund, which has helped cover state spending for all but two years since 1991, will hit empty by Labor Day 2004. Alaska may be resource rich but we are cash poor—unless you count the Permanent Fund. Other than taking money out of the Permanent Fund to invest in a gasline, the state is in no position to write a check for any significant investment in a gas pipeline project, regardless how good the investment.

The Alaska Permanent Fund

There are several options for using the Permanent Fund for state investment in the project:

- Spend money from the Earnings Reserve Account to buy in as a gasline partner. This means going into the business of owning and operating a natural gas pipeline. This could be done by a legislative appropriation to another state agency or new state corporation to make an equity investment in the pipeline. However, withdrawing too much from the Earnings Reserve Account could jeopardize its future ability to pay for inflation proofing of the fund's principal and dividends.
- The legislature could change state law to authorize a direct investment by the Permanent Fund in the gasline business. A statute change would be required because the Permanent Fund's investment authority does not cover going into the gasline business.
- Or the Permanent Fund, as part of its regular asset allocation and investment mix, could decide to buy shares in a public traded corporation or buy bonds issued by the corporation or corporations that own the pipeline. These investments, however, would give the state no more control over the project than any other minority shareholder, and any return would depend on the corporation's performance and stock or bond value. Any such investment would—by constraint of the Prudent Expert Rule for Permanent Fund investments—be limited to a small percentage of a pipeline corporation's stock or debt.

Taking on State Debt

The state and its municipalities are looking at how to pay for several billion dollars of school construction and repairs, and deferred maintenance to public facilities. The state, which has not issued any general obligation bonds in nearly 20 years, will go to market in the next year if legislators agree with the governor's proposal for school bonds. Taking on new debt for schools and other needs most likely will consume all of the state's available debt capacity, unless Permanent Fund earnings are diverted from the dividend program to pay debt service.

Any over-ambitious reliance on debt to finance a state investment in the gasline could jeopardize Alaska's credit rating, which could have a domino effect as it raises the cost of borrowing for the state and municipalities.

Rate of Return

The Federal Energy Regulatory Commission in the United States and the National Energy Board in Canada would regulate the rate of return on any interstate pipeline, and we expect that return would not differ significantly from what the state—or the Permanent Fund—could earn in other investments with similar risks.

Risks to the State

State investment as a partner in the project could put the state at financial risk if there are construction overruns, delays in completion of the project, unbudgeted calls for additional capital, or volatile natural gas market conditions. Unlike large corporations, the state does not maintain reserves for such risks, and it would be a difficult policy call to tell the public that key government services might be cut back to make money available for gasline expenses.

State Control

Proponents who advocate state financial participation in the project for reasons of control raise two points: (1) Alaska should take a stronger hand in managing its resource development, and (2) a belief that North Slope oil producers took advantage of the state by inflating tariffs on the Trans-Alaska Pipeline System, thereby reducing their oil tax and royalty payments to the state.

Both are emotional issues, and both require an unemotional review.

First, whether the state should take an active role in managing the development and marketing of its oil and gas resources is a public policy call. If people believe that is the overriding issue in this project, then it might justify the financial risks to the state. However, advocates of this position should carefully weigh the risks against the potential benefits. Could state participation in the gasline make it happen any sooner? Would state participation dissuade corporations from putting up their own billions—private money that Alaska needs. And is it the role of government to build and operate for-profit ventures? We believe the state could best control the development of its resources by regulating their extraction and use, and

project. The lower cost of tax-exempt debt could help tip the project toward economic feasibility, and that could be a proper role for the state to take in assisting in the development of its natural resources. Even with the lower interest rate on tax-exempt debt, however, it is still possible that the companies might choose to issue their own taxable debt in order to take advantage of the federal tax benefits of owning and depreciating the line.

As it says in the cover letter to this report, there are no easy answers.

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672
2959 SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPLINES, 2001-02

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SECTION 1

Introduction

This report analyzes opportunities for the State of Alaska to financially participate in a pipeline to transport natural gas from Alaska's North Slope to domestic or foreign markets. The project is generally referred to in this report as the Alaska Gas Pipeline. The Alaska State Legislature, by passage of Senate Bill 158 in May 2001, directed the Commissioner of the Department of Revenue to prepare this report.

The analysis looks at a number of options for financial participation, ranging from outright state ownership to financing a project owned by others. It discusses the possible financial risks and rewards for each option and, where enough information is available, presents conclusions.

This report is not specific to any one proposal for commercialization of Alaska gas. Proposals include transporting North Slope gas to either Alberta, Canada, to feed into the existing North American pipeline grid for shipment to U.S. markets, or to tidewater for liquefaction and shipment of liquefied natural gas (LNG) to domestic or overseas markets.

A North Slope gas pipeline has been seriously considered since the 1970s, but to date questionable economics have always blocked its construction. The project is further complicated—or aided, depending on your perspective—by the significant amount of study, legislation, development and permitting that have already occurred or may yet need to occur in the United States and Canada.

This report uses the existing body of work on state participation in a pipeline as the starting point for its analysis. The team that produced this report included the Alaska Department of Revenue, its economic and financial consultants, and attorneys specializing in public finance and law. In addition to its own analysis, the team interviewed Alaska policymakers, oil and gas company officials, pipeline company representatives and other interested parties to obtain ideas and opinions on state participation in the project.

Key criteria used to analyze the options include the effects on the economic and financial health of the state of such a large investment, the potential for risks to the state, and whether state participation could actually help the project. Estimates of project costs, financing parameters and financial risks were used to analyze the consequences of state investment in the project and to determine the effect on the state's financial position. State funding sources were assessed in terms of legal and financial possibilities.

This report is organized into the following key sections:

2) Background, provides information on Alaska oil and gas development. It also discusses the state's economic and financial profile.

3) Alaska Gas Pipeline Overview, discusses pipeline route proposals and sponsors, and opinions expressed for and against the pipeline during interviews conducted for this report.

4) Ownership and Financial Participation Options and Evaluation Criteria, identifies the ownership and financing options to be considered as specified in SB 158. It also presents the evaluation criteria specified in SB 158 and identifies additional evaluation criteria considered in this report.

5) Evaluation of Financial Participation and Ownership Options, lists and evaluates each of the sources of state funds for a potential equity investment, financing options, and ownership alternatives.

6) Investment Setting, discusses the key factors affecting potential risks and returns for an investment in the Alaska Gas Pipeline, including future gas market conditions, governmental regulation, permit requirements and project costs.

7) Potential Returns from Pipeline Investment, evaluates the risks associated with the project and reviews potential returns associated with each of two investment options: pipeline ownership and ownership of capacity rights purchased from the pipeline owner. This section also discusses potential effects of an investment on the state's cash flow.

8) Effect on State of Alaska from Pipeline Investment, evaluates the effects of state ownership options on Alaska's financial position. This section looks at the state's

financial integrity and creditworthiness, and its credit rating. It also discusses balancing the benefits to the state vs. the costs of a pipeline investment.

9) Effect of State Participation on Project Success, discusses the value of access to information that might be gained from state participation and assesses possible conflicts of interest in the state's potential dual roles as an owner and regulator. This section also looks at how state participation might help or hinder project completion and operation, and identifies how other parties participating with the state might benefit or suffer from state participation.

10) Conclusions and Recommendations, presents conclusions regarding state participation.

11) References and Acknowledgements, provides a list of the resources used in preparing this report.

confirmation hearings, promised he would not lift the land freeze without consulting the Senate Committee on Interior and Insular Affairs.

After several exchanges with the Senate Committee, Secretary Hickel in January 1970 modified the land freeze to open federal land for the pipeline right of way. Almost immediately, two court injunctions were issued prohibiting the proposed right-of-way grant. The Alaska Native residents of Stevens Village successfully obtained an injunction as a consequence of their claim to lands the pipeline would need to cross. The Wilderness Society obtained a separate injunction on the basis of the newly enacted National Environmental Policy Act and a claim that the proposed pipeline right of way was wider than permitted under applicable federal law.

After these two injunctions were issued in early 1970, the oil companies—along with the state, Alaska Natives and the environmental community—all turned to Congress to resolve the Alaska Native land claims and to squabble over establishing a substantial list of proposed parks, wildlife refugees and wilderness areas in Alaska.

Before the injunctions were granted—and believing that North Slope oil would soon be moving to market—the Alaska Department of Natural Resources auctioned the state's unleased North Slope acreage and received $900 million in bonus payments from the winning bidders. By the summer of 1970, however, state officials had become frustrated with the delay. Apparently, the governor and other state policymakers believed state construction and ownership of the proposed oil pipeline could provide a way around the roadblocks created by the unresolved Alaska Native land claims and the objections of the environmental community. To that end, Governor Keith Miller appointed a 15-member citizens group comprised of prominent citizens from Alaska's business and labor communities to examine the benefits of state ownership. To accomplish this mission, the Governor's Pipeline Commission, as it was called, hired the international consulting group Harbridge House Inc. to report on the feasibility of state ownership and operation of TAPS.

Harbridge House issued its report in December 1970. In its report, Harbridge concluded that state ownership would neither avoid nor resolve the Alaska Native land claims issues. Harbridge reached similar conclusions regarding the environmental community objections. In the consultant's view, state ownership would not accelerate the resolution of the problems

causing the delay and private enterprise could construct the pipeline more expeditiously than state government.

Although Harbridge acknowledged that state ownership (1) could lead to lower tariffs because the state would not be subject to either state or federal income tax or municipal property taxes, and (2) could provide the state with access to information about pipeline costs and tariffs that would otherwise be unavailable, the consultants nevertheless concluded state ownership simply was not feasible. To reach this conclusion, Harbridge observed that the state lacked the experienced staff needed to manage such an enterprise and that the state would jeopardize its ability to provide necessary public services if it took on the financial and operating risks of the oil pipeline.

Finally, Harbridge expressed the view that it was unlikely the state had the financial strength needed to borrow the amount of money required to construct the project.

The Harbridge report was released just as Bill Egan succeeded Keith Miller as governor in December 1970. Possible state ownership of TAPS was reconsidered in the early months of his term and, on October 31, 1971, Governor Egan announced he had decided to proceed on a course of action leading to state ownership of the proposed pipeline. He based his decision on the potential financial benefits of state ownership outlined in the Harbridge report.

Governor Egan presented his proposal to TAPS owners, believing that state ownership would be feasible only if the oil companies supported it. The immediate response from the joint venture was negative. Nevertheless, in late 1971, the state again retained several consultants to examine the feasibility of state ownership.

The administration concluded—based upon the consultants' advice—that a state-owned pipeline was desirable and could be financed and constructed on the same schedule as a privately owned pipeline under the following conditions:

- That Alyeska Pipeline Service Company, the management company established by the TAPS owners to construct and operate the pipeline, would agree to act as the state's contractor for construction and operation of the line.

- That the major North Slope oil-producing companies would guarantee shipment of sufficient quantities of oil to generate enough tariff revenue to pay for the pipeline.
- That the major North Slope producers would guarantee completion of the pipeline.

In 1972, the Egan administration proposed legislation to implement the plan for a pipeline constructed and owned by the state. The oil companies opposed the proposed legislation, and it was not enacted.

Congress eliminated the land claims issue as a barrier to constructing an Alaska oil pipeline when it passed the Alaska Native Claims Settlement Act in December 1971. The Wilderness Society lawsuit, however, remained an obstacle. In February 1973, the U.S. Court of Appeals for the D.C. Circuit held that the Secretary of Interior lacked the authority to issue the permit for the proposed TAPS right-of-way. The state and the companies then turned to Congress for relief. Congress obliged and provided the Secretary with the necessary authority by passing the Trans-Alaska Pipeline Authorization Act in October 1973. Pipeline construction began in early 1974.

The TAPS owners then turned to the state for assistance in obtaining tax-exempt financing for the project's marine terminal at Valdez. If it could be established that the marine terminal was a public port, then financing by a public entity could be tax exempt. The oil companies requested the Alaska Industrial Development Authority to sponsor the proposed financing, but Governor Egan opposed the plan and instructed the authority not to approve it. Tax-exempt financing for the marine terminal in an amount totaling $1.265 billion ultimately was arranged through the City of Valdez. The bonds were secured solely by the security of the companies and did not involve the credit of the City of Valdez. The city obtained a 1 percent impact fee from the financing, which it placed in a permanent fund.

When oil started flowing through the pipeline in June 1977, the state initiated litigation over the tariffs for shipping oil on TAPS. Much of the state's revenue was calculated after tariffs were deducted from the value of the oil, and the pipeline tariffs had become a major point of contention between the state and the TAPS owners.

In July 1977, a representative of BP Pipelines Inc., owner of 16.6 percent of TAPS, approached the state and proposed selling its share of the pipeline to the state. BP's

representative suggested that the proposal would align the state's interest with those of the other pipeline owners. BP contended that state pipeline ownership in an amount almost equivalent to its economic interest in the oil production stream (at the time a royalty interest of 12.5 percent and a production tax interest of almost 11 percent) would eliminate the need for the state to battle the companies over pipeline tariffs. The state declined to pursue the proposal, in part, because state officials believed state ownership would unacceptably increase the conflict between the state's regulatory responsibilities with respect to pipeline operation and the state's interest in maximizing public revenue.

BP's proposal to sell the state its share of the pipeline was renewed in February and March 1978 and again rejected by state policymakers.

State Participation in Gas Pipeline Development

At the same time that state officials were considering BP's proposal to sell the state its share of the oil line, they also were considering possible state investment in a proposed pipeline to carry North Slope gas to market. Northwest Pipeline Company (now the Williams Companies) was the leader of the group of companies that in 1978 had obtained federal approval in 1978 for its proposal to build the Alaska Natural Gas Transportation System (ANGTS), a gas pipeline from the North Slope to Fairbanks and then down the Alcan Highway to mid-North America. Northwest Pipeline said it needed help from the state to finance the proposed project. The company, headquartered in Salt Lake City, operated pipelines from gas fields in the Rocky Mountains to markets in the mountain states and Pacific Northwest.

But it was almost a decade earlier, just one year after the Prudhoe Bay discovery in 1968, that Arctic Gas, a consortium of major North Slope producers with other producing and gas pipeline companies, began a series of studies on how best to move Prudhoe Bay gas to market. These studies, which started in 1969, culminated in a March 1974 application to the Federal Power Commission (FPC) for a certificate to construct a pipeline across Northern Alaska and Canada to the Mackenzie Delta and then up the Mackenzie River to Alberta and mid-North America.

harvests in 1998.[5] Although the fishing industry experienced its ups and downs during the 1990s, it averaged 4 percent of the gross state product and was responsible for 7 percent of statewide employment.[6] Unfortunately for Alaska, the strong growth in the worldwide farmed salmon industry has caused major problems for the state's natural fisheries. Low prices and oversupplies in the market are creating troubles for Alaska fishers, processors and communities.

Mining

Between 1999 and 2000, production of minerals increased by 5 percent to $1.1 billion, in part due to the increased value of zinc. Development expenditures in 2000 increased to $137 million from $34 million the previous year. This is mostly due to expenditures at Red Dog, Greens Creek, Fort Knox and Pogo mines.

State and Local Government

During the 1990s, state and local government accounted for 12 percent of the gross state product and 18.5 percent of Alaska's employment.[7] The Alaska Permanent Fund dividend pumps around $1.1 billion into the economy each year. The state's unrestricted general fund budget is at $2.4 billion for the fiscal year ending June 30, 2002.

Transportation

Because of Alaska's size, isolation and dependence on natural resource exports, the transportation sector is particularly important. The percentage of private employees in the transportation sector in Alaska is twice as large as in the nation as a whole. Employment in the air transportation sector grew by 37 percent between 1990 and 1998 and accounts for more than 10,000 jobs.[8] Alaska's location—equidistant between Europe and Asia—has made it an important international hub for airfreight. Anchorage International Airport is the No. 1 airport in the United States in the amount of freight landed, with approximately 650 million

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[5] U.S. Department of Commerce, National Marine Fisheries Service, Office of Science and Technology, Fisheries Statistics and Economics Division, "Fisheries of the United States 1999." October 2000.

[6] Institute of Social and Economic Research, *Trends in Alaska's People and Economy* (October 2001).

[7] Institute of Social and Economic Research, *Trends in Alaska's People and Economy* (October 2001).

[8] Alaska Department of Labor and Workforce Development. Alaska Economic Trends, "Transportation." November 1999.

pounds of freight in Fiscal 2001. The airport is responsible for about one of every 10 jobs in Anchorage.[9]

Tourism

Tourism has grown rapidly in the past 10 years. For example, from 1990 to 1998, summer visitors increased from 690,000 to 1,135,000. From October 1997 to September 1998, tourists spent approximately $949 million in Alaska. The tourism industry generated an annual average of slightly less than 16,000 jobs in 1998.[10]

Outlook

Alaska Department of Labor statistics show that moderate growth of the Alaska economy has continued even in the face of the nationwide recession. Yet, as discussed below, state government has been a significant source of "new" money in the economy during the past two decades because it has pumped money derived from the oil industry and Permanent Fund dividends into the economy. As the state begins to use "recycled" money—money from taxes on residents or money from reduced dividends—the economy will necessarily contract unless a new source of new money is found. Although new money is possible through new projects, such as the Alaska Gas Pipeline, economists would not consider the economy stable because the projects on the drawing board are, at this time, too uncertain. Thus, the facts presented below indicate that during the next few years the Alaska economy may not be as robust as it has been in past 25 years.

State Government Fiscal Profile

In examining the state's fiscal profile, three facts command overwhelming attention:

1. The state's tax base is extremely concentrated—in fact, three tax and royalty payers were responsible for more than 75 percent of the money spent from the general fund in Fiscal Year 2001.

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[9] Scott Goldsmith, University of Alaska; "Anchorage International Airport: 1998 Economic Significance." September 1998.

[10] McDowell Group Inc. "Economic Impacts of Alaska's Visitor Industry 1999: Update, May 1999."

2. The state is spending more money each year than it takes in as revenue, and will soon reach the point where its readily available fiscal reserve (the Constitutional Budget Reserve Fund) will no longer be available to balance the state budget.
3. The state has $25 billion in a large savings account, the Permanent Fund, the principal of which cannot be spent but which has a very large earning capacity.

The narrowness of the state's tax base is a result of the state's reliance on its oil and gas industry to supply almost all of state income since the beginning of Prudhoe Bay production. Oil started flowing from Prudhoe in 1977, and three years later the legislature repealed Alaska's personal income tax and gross receipts business tax. Although municipalities have sales and property taxes, the state has no state sales tax or property tax, except for a property tax on oil and gas property.

Reliance on oil industry taxes and royalty payments worked very well for the state for many years, producing unprecedented budgets and even surpluses during the early '80s. In 1988, however, Prudhoe Bay production peaked, and state revenue has been in the decline ever since.

In addition to overall declining revenue, the state also experiences volatile revenue. Given the narrow tax base, the state's fiscal system is very dependent on the health of the oil industry. During the early years of North Slope production, the state enjoyed the ride of high oil prices during the late '70s and early '80s. It then felt the full brunt of the crash in 1986, when the price of Alaska North Slope crude fell from $22.25 in January 1986 to $9.72 per barrel in July 1986. State revenue fell by 42 percent due to the fall in oil prices. In response, the state reduced its workforce by 10 percent. There were almost 2,000 fewer state workers in 1987 than in 1985. The state's capital budget was reduced from $2 billion in 1985 to $343 million in 1987.

In the face of declining state revenue and the dependence on volatile oil prices, Alaska voters amended the constitution to create another reserve account in addition to the Permanent Fund—the Constitutional Budget Reserve Fund (CBRF). The state funded the CBRF with money from settlement of tax and royalty disputes with the oil companies—revenue largely owed from the boom decade of the '80s.

Although oil prices—and state revenues—recovered from the crash of 1986, the state's annual spending in the 1990s began to exceed the amount received each year as "unrestricted revenue." The decline in state revenue is not due solely to declining oil production. It's also the consequence of a provision in the state's oil and gas production tax, called the Economic Limit Factor (ELF), which lowers the tax rate on less productive fields. The idea behind the ELF is that less productive fields are more costly to operate, so a lower tax rate will keep old fields in production longer and encourage development of marginal fields. With more production, the state benefits in the long run. As the state's highly productive large fields age, however, and the ELF formula kicks in, the state is experiencing a significant reduction in oil tax revenue.

During the 1990s, the state managed to avoid deficit spending by reducing its budgets and drawing down the CBRF. The balance of the CBRF, as of January 1, 2002, was $2.65 billion. The projected budget deficit for Fiscal Year 2002—the budget gap—is $865 million; for FY 2003, it's $1.078 billion. Assuming no changes in budget or taxes, the Department of Revenue predicts the CBRF will be depleted by late summer 2004, under any reasonable oil price scenario.

A bright spot on the state's financial profile is its Permanent Fund. The 1976 constitutional amendment requires that at least 25 percent of the state's oil, gas and mining lease bonuses, rentals, royalties and federal mineral revenue sharing payments are deposited into the fund.

The fund has grown significantly over the years through its investment earnings, and as of January 1, 2002, had a market value of about $25 billion. The fund expects to earn, on average, about 5 percent per year after inflation.

According to the constitutional amendment, the legislature may spend the earnings of the fund for any public purpose, but the amendment offers no guidance on what that might be. Early in the fund's existence, the legislature established a dividend program to distribute some of the fund's earnings to the residents of the state. The annual dividend is calculated under a statutory formula that distributes approximately one-half of the actual realized earnings, and then deposits into the principal of the fund the amount necessary to "inflation proof" the principal. The 2001 dividend was $1,850 per person. Not surprisingly, the dividend program is extremely popular with Alaska residents. Any earnings left over after

dividends and inflation proofing are deposited into the fund's Earnings Reserve Account, where the money is invested just as the fund's principal and its earnings are included in calculating the annual dividend. The legislature has in the past transferred significant portions of the Earnings Reserve Account into principal, but in recent years the practice has been to allow the reserve to accumulate. Although there are different ways of calculating the value of the reserve, the balance at the end of Fiscal 2002 is expected to be about $3 billion. To date, the Earnings Reserve Account has never been spent on state services.

Another bright spot is the state's low level of debt. Although Alaska did some bonding for capital projects during the early years of the pipeline, those bonds were timed to mature with the "Prudhoe Bay curve" such that as oil revenue declined, debt service payments also declined. Currently, the state has no outstanding general obligation bonds, although, as of June 30, 2001, it owed more than $70 million in certificates of participation, a type of debt used for lease/purchase of state assets.

One consequence of the low level of capital spending, however, is that the state is behind in building and maintaining many of the facilities needed by a growing state. In January 1998, the Deferred Maintenance Task Force, a group commissioned by the legislature, issued a report recommending spending $1.4 billion on schools (both major maintenance and construction), the university, highways and airports, the state ferries, harbors, buildings, American Disabilities Act requirements, and water and sewer upgrades. Although approximately $200 million of these projects have been completed, additional projects, including up to $641 million in school projects, have been identified to add to the total.

In summary, although Alaska has a reasonably strong economy, the state's fiscal profile is in flux. This is not to suggest that the state government is facing an insurmountable economic crisis—solutions to the problem do exist, and will be found. The state's fiscal situation, however, does suggest two important considerations.

First, it should be clear that state policymakers are going to have to wrestle with changes to the state's fiscal regime. They must determine whether this is the appropriate time to consider an investment in a project as large as the proposed gas pipeline. Policymakers must be aware of the time and resources that such an investment would require, and the financial risk such an investment would entail. Alaska currently does not have a long-range fiscal plan,

and the state will soon need to identify new revenue sources and/or immediate budget reductions. This all must be done before the gasline would generate any revenues. The timing, therefore, is not favorable.

Second, it should also be clear that the CBRF is not a potential source of revenue for investment in the project. The state currently relies on the dwindling CBRF to help pay for needed public services each year. Due to the volatile nature of Alaska's oil and gas tax and royalty revenues, the state must retain enough money in the CBRF—unless Alaskans are willing to use the Permanent Fund for that purpose—to provide the equivalent of "overdraft protection" for years of low oil prices. Without the CBRF to protect the state during the inevitable years of low oil prices, Alaskans could face the prospect of losing essential state services, seeing their dividends cut, or taking money out of the Permanent Fund to balance state spending. Accordingly, this report does not recommend that the state invest CBRF money in the project.

SECTION 3

Alaska Gas Pipeline Overview

Just as there were multiple proposed projects and potential developers in the 1970s, there is a similar list of possible participants and pipeline plans for the start of the 21st century. This section describes the major proposals and proponents. It is expected, however, that because of the huge scale of the project, proposals and sponsors may shift and realign over time. This section also presents information summarizing citizen and industry opinions about the advisability of state ownership.

Currently, pipelines—or pipelines in combination with liquefied natural gas (LNG) plants—are the only options being studied by the major producers and pipeline companies for bringing North Slope gas to market. An alternative that has been discussed from time to time is a process known as gas-to-liquids (GTL) conversion technology. This process converts natural gas to refined liquid petroleum products, which could be shipped to market via the TAPS oil pipeline to Valdez. However, GTL—which consumes large amounts of gas in the conversion process—is not expected to be economical for marketing North Slope natural gas in the reasonably foreseeable future.

Proposed Pipeline Routes

There are three general pipeline routes under active consideration in 2002 by parties proposing to move North Slope gas to market. They are all shown in Figure 3-1.

1) **Alcan Highway Route.** The route follows the TAPS oil pipeline from Prudhoe Bay past Fairbanks to Delta Junction. From Delta Junction, it generally follows the Alcan Highway across eastern Alaska, the Yukon Territory and northeastern British Columbia to central Alberta. There, Alaska gas would connect with the existing North American gas pipeline system. The governor of Alaska currently favors this route, and Alaska state government is devoting significant time and money to promote it.

2) **Over-the-Top Route.** The route follows the shoreline in the shallow offshore waters of the Beaufort Sea from Prudhoe Bay 370 miles to the Mackenzie Delta in Canada's Northwest Territories. From the Mackenzie Delta, this route continues 850 miles up the Mackenzie River Valley and into northern Alberta. A pipeline following this route would move gas to the mid-North America market from both the Alaska North Slope and the Mackenzie Delta. Alaska's governor and legislature strenuously oppose this route. The legislature in 2001 passed a bill—Senate Bill 164—prohibiting rights of way for any pipeline following this route. Environmental groups and Alaska Natives living on the North Slope also strenuously oppose using this route for fear of disturbing the sensitive North Slope marine environment.

3) **All-Alaska Route.** This route parallels the oil pipeline from the North Slope to Valdez. Once at tidewater in Prince William Sound, the gas would flow into an LNG plant that would liquefy the gas so that it could be transported in specially constructed tankers to markets in East Asia or the U.S. West Coast and Mexico. Advocates of the route have submitted petition signatures to the lieutenant governor for a November 2002 statewide vote to create a government-owned corporation called the Alaska Natural Gas Development Authority to develop the state's North Slope gas resources. The initiative, if approved by voters, would direct the corporation to promote, build and operate a project using the All-Alaska Route.

Some potential project sponsors have also proposed a so-called "Y" Line that combines elements from the Alcan Highway Route and the All-Alaska Route in order to access multiple markets. Under these proposals, the sponsors would construct pipelines both down the Alcan Highway to mid-North America and to an LNG plant near Valdez. This proposed routing could provide North Slope gas to mid-North America, East Asia and the West Coast of the United States and Mexico.

Some project sponsors have also suggested the possibility of constructing spur lines to transport gas to the Southcentral Alaska distribution grid. Both the Alcan Route and the All-Alaska Route could accommodate projects that include a spur line from Fairbanks to connect with the Southcentral distribution grid in the southern Susitna Valley. The All-Alaska Route

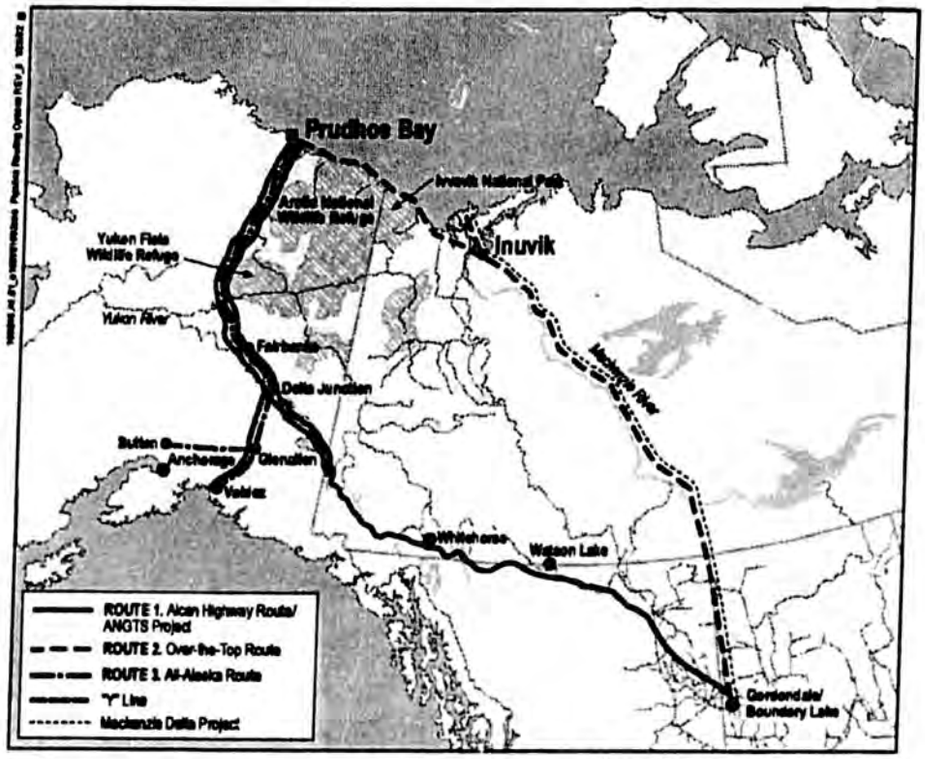

Figure 3-1
Proposed Pipeline Routes

would also accommodate a spur line from Glennallen to the end of the distribution grid at Sutton.

Potential Projects

1) Alaska Gas Producers Pipeline Team Projects

Three major producers—ExxonMobil, BP and Phillips—hold the working interest in most of the discovered natural gas reserves on the North Slope. The discovered reserves in two units—the Prudhoe Bay and Point Thomson units—make up a large proportion of these reserves.

On several occasions since the Prudhoe Bay discovery in late 1967, these three producers, or their predecessors in interest, have considered options to commercialize North Slope natural gas. Most recently, they formed the Alaska Gas Producers Pipeline Team to study the feasibility of constructing a pipeline from the North Slope to mid-North America. They

Port Authority's Combined Alcan Highway and All-Alaska Project

- Volume: 3.0 bcf per day of North Slope gas down the Alcan and 3.0 bcf per day of North Slope gas to an LNG plant at Valdez.
- Project cost: $18 billion for the pipelines only in Alaska (the Port Authority proposal includes no pipe beyond the Canadian border); a gas conditioning plant on the North Slope; and the liquefaction plant and LNG terminal at Valdez. The necessary pipe from the Canadian border into Alberta and beyond could add several billion dollars more to the total cost of serving the market.

4) Arctic Resources Company (ARC)

Arctic Resources Company is a Houston-based corporation formed in 1999 that, together with its Canadian affiliate ArctiGas Resources Ltd. Partnership, proposes to construct a pipeline using the Over-the-Top Route to transport North Slope and Mackenzie Delta gas to market. The company has announced it plans to place ownership of the project in the hands of Alaska municipalities and Canadian First Nation groups. ARC believes this ownership structure would make the project exempt from corporate income taxes in both countries. ARC favors the Over-the-Top Route for economic reasons—the company believes a pipeline using this route could bring gas to market at a lower cost. However, in a bow to Alaska politics, the company proposes using project revenue to finance development of a gas supply to Fairbanks through extraction and distribution of propane from the TAPS crude oil stream.

ARC's Over-the-Top Project

- Volume: 4.0 bcf per day of North Slope gas and 1.2 bcf per day of Mackenzie Delta gas.
- Project cost: $7.8 billion, not including the cost of a North Slope gas conditioning plant or the cost of building new take-away capacity from the project's Alberta terminal.

5) Alaska Natural Gas Development Authority

If the All-Alaska Gasline Initiative that would establish the authority passes in November, the authority will have the responsibility to promote a project using the All-Alaska Route together with a spur line from Glennallen to Sutton. The project would include a gas conditioning plant on the North Slope and an LNG plant on Prince William Sound. The authority would be responsible for arranging to finance and build the project, and for buying, transporting and marketing the gas.

Collateral Infrastructure

With the substantial volume of new gas supply flowing to Alberta through the Alcan Route, new take-away pipeline capacity would be needed to transport gas out of Alberta and into U.S. and Canadian markets. This would be necessary because the existing pipeline capacity from Alberta is expected to be fully utilized by the time an Alaska line is completed. It is uncertain exactly how this new capacity would be added, although it likely would include capacity upgrades on existing pipelines as well as construction of new pipelines. For planning purposes, one sponsor has estimated the cost of a single new so-called "bullet" pipeline from Alberta to Chicago at $5.3 billion.

All projects would require construction of a gas conditioning plant to prepare North Slope gas for transport by pipeline. The North Slope oil producers have estimated the cost of a 4 bcf per day plant at about $2.6 billion. The Alaska Gasline Port Authority has estimated the cost of a 6 bcf per day plant at $4.2 billion.

In addition, natural gas liquids extraction facilities would be needed for each route. The North Slope oil producers estimate the cost of these facilities to be about $300 million for either the Over-the-Top or the Alcan Highway Route. The Alaska Gasline Port Authority estimates the cost at about $400 million for a plant at Valdez.

The All-Alaska Route would require investment in LNG facilities in Valdez, as well as expansion of marine shipping facilities. The Alaska Gasline Port Authority has estimated the construction cost of the LNG facility at about $4.1 billion, including a liquids extraction plant.

2) The state should invest to protect its financial interests and control its own destiny. This category can perhaps best be described as taking steps to ensure that Alaska benefits as much as possible from the project, and to ensure that the state treasury receives all of the money it should from the sale of North Slope natural gas.

Many of the opinions centered on the value of a "seat at the table." Most people believe the state needs to have a seat at whatever table pipeline owners sit at as they discuss costs, management decisions, flows, operations, maintenance needs and whatever else partners talk about. Most of those interviewed cited years of contentious disputes between the state and the Trans-Alaska Pipeline System owners over transportation tariffs for moving crude oil from the North Slope to Valdez as something they would prefer to avoid in an Alaska Gas Pipeline. Many believe the state has not received as much tax and royalty revenue as it might have from North Slope oil because of excessive pipeline tariffs, and they are convinced a seat at the table of gasline owners would prevent a repeat of those problems. The tariffs are important because the state's royalty and production tax revenues are calculated after transportation costs are deducted from the sales price for the oil or gas.

In addition to knowing what the pipeline owners are spending and how it might affect the tariffs, many interviewees said signing on as a project partner could put the state in a better position to influence several key decisions: pipeline route, Alaska-hire provisions for construction and operation of the line, and provisions for in-state use of some of the gas. Of those who want to push for in-state spur lines and off-take provisions for local use of the gas, most acknowledged that even as a partner the state could not require any business to build or operate an unprofitable venture. They said any in-state project would have to stand on its own financial feet.

Interestingly, although there has been much interest in stripping the gas liquids to develop a petrochemical industry in Alaska, the interviewees were split on whether that made economic sense. Several were strong in their words that they did not want to see a "Petrochemical Gulch," as they called the Houston, Texas, area, developed in Alaska.

And while most everyone said they favor the Alaska Highway Route for a gasline, those same people said the major players probably would have made that decision long before the state signed on as an investor.

Regarding state involvement in control and oversight of project decisions, the group was about evenly split on whether acting as a business partner would be a conflict of interest for the state in its main role as a taxing authority, environmental and job safety regulator.

3) Many said state participation could help make the project more viable—simply put, moving it along so that it gets built sooner rather than later. Everyone interviewed said they would like to see an Alaska Gas Pipeline built for the money it would bring to the state treasury, for the construction jobs it would create, and for the economic boost a new industry and potentially cheaper energy would bring to Alaska. The dilemma for many was how state participation could move along the start date for construction. Certainly, state financial participation could help if the State of Alaska could find a way to lower the cost of the project, but all but a few acknowledged that would be difficult to manage.

Some thought the sheer political will of Alaska and a strong voice at partner meetings, perhaps even some delicate pushing, could get the project off the planning boards and into the groundbreaking stage. One referred to state participation as the "jump start" to the project by sending a positive signal to gas producers, pipeline companies and potential investors. However, others admitted they are skeptical that state participation as a project partner could have any immediate effect on whether the project gets built.

Some, however, cautiously warned that state involvement in the project, coupled with Alaskans' perception that natural gas would create new industries in the state, could lead state officials to push for uneconomical restrictions or side projects to the pipeline—"skew the decision making," as one person said. Or, as another said, emotions of the day can stampede government into making bad decisions. The other side said having the state participate as a partner could be a good learning experience, in that Alaskans could see from others that some dreams are unprofitable—in effect saving us from our own mistakes.

Industry Consensus

The list of interviewees from industry included representatives of:

- ExxonMobil
- Phillips
- BP
- Anadarko
- Alberta Energy
- Duke Energy
- Williams Companies
- TransCanada
- Westcoast Energy
- El Paso Energy

The natural gas industry representatives were very aware of the economic benefits the project represented. However, they viewed the gasline as a private-industry project and not one that required or was logical for state participation. Their rationale is as follows:

- The companies believe the state does not need a "seat at the table" to ensure that it has access to the all the information it requires. The state can gather most of the information it needs regarding pre-construction activities by active participation in the Federal Energy Regulatory Commission (FERC) and Canada's National Energy Board (NEB) process. The state also would be actively involved through its own regulatory oversight process. After construction, the state would continue to have access to the information it needs through state and federal public filings and private discussions with the gasline owners.
- Several companies believe the state is not necessarily adept at making rational business judgments. The open marketplace will dictate where gas development projects can and will be developed within the state. The state, however, may want its joint-venture partners to pursue gas development projects that are politically popular, but uneconomic.
- Industry believes that if the state were a member of the joint-venture governing board, the joint-venture might not be able to move quickly enough when key decisions are needed.

And, again, the state's decisions might not be made on the basis of economics, but for political reasons. Management of any major joint venture is difficult, and industry believes that government participation at the table would only magnify these management difficulties. Given the size of the project, the financial consequences of any delay can be significant.

- Although several companies acknowledge that state participation might ease or expedite the issuance of state permits, it is not believed that the state would be useful in the federal or Canadian permit process. The companies have significant, relevant experience in handling these issues.

- Many companies thought the state might be in a natural conflict-of-interest position as both an equity holder and as a regulator. This might create tension on the joint-venture management committee because the private company members might question the motives of controversial state decisions. Some companies questioned how the state could properly balance its legal and moral obligations to its citizens with its fiduciary obligations to its joint-venture partners.

- Industry believes that if the Alaska Gas Pipeline is economically viable, the sponsors would have access to more than adequate capital from existing financial markets, likely at better terms than the state could offer. In fact, state participation might make financing more problematic due to the nature of the sources of the state's equity or debt funding and requirements the state might impose to safeguard its investment.

- Some companies believe that proponents of state ownership are motivated by the prospect of a high direct rate of return on the pipeline investment, and that this motivation would be much less if they understood that the returns would be regulated.

- Industry is of the opinion that the amount of money the state probably would be able to invest—and the amount of equity participation percentage the sponsors likely would wish to sell—would allow the state to obtain only a small, minority position restricted in terms of management participation and access to day-to-day information.

- In at least some proposed organizational structures, the same joint venture would own and operate the entire pipeline from Alaska to Canada. In that situation, it might be inappropriate or politically unfeasible for the state to own an interest in foreign assets.

More importantly, industry does not believe that state equity participation would materially advance the construction of the gasline, assist its operation or enhance its profitability. Several companies believe state participation would actually *hinder* the project. Today's situation is not at all like the early 1970s, when state participation was actively sought by many of these same proposed developers. Industry now believes it has adequate resources to ensure the success of the project without state involvement. As many companies stated, this is a private project, not a public one.

Although industry has acknowledged the state could force its way into the joint venture, it appears unlikely any of the competing sponsor groups would welcome the state's attempt to become a partner.

SECTION 4

Ownership and Financial Participation Options and Evaluation Criteria

As noted in the Introduction, this study was mandated by passage of Senate Bill 158 in the spring of 2001. The bill is provided in Appendix A.

The legislative purpose was to obtain analysis and recommendations regarding State of Alaska options "to participate in commercial development of the state's natural gas resources through ownership of or provision of financing for a gas pipeline project." Further, the bill directs the Commissioner of Revenue to consider specific ownership and financing options and to evaluate these options according to specific criteria.

Ownership and Financing Options

SB 158 gives five directives for this report. Three relate to ownership and financing options, and two relate to evaluation criteria. The state ownership and financing options are:

- Participate by taking an equity position in a gas pipeline project by owning all or a portion of the project, or establishing a state-owned public corporation or authority to construct and operate the project.
- Participate in financing the project, which could include issuing general obligation bonds or revenue bonds of a state-owned public corporation or authority, or in another appropriate form such as guaranteeing debt. The review should include what terms the state, or its public corporation or authority, should require as conditions for providing financial support for the project.
- Participate by establishing a private corporation that would be comprised of Alaska residents who wish to become shareholders of a new corporation that would own a portion of the project or assist in the construction and operation of the project.

In addition to these directives, the Commissioner of Revenue has given consideration to whether the state should participate in commercial development of the Alaska Gas Pipeline by purchasing capacity rights from pipeline owners.

Evaluation Criteria

The two evaluation directives require use of the following criteria in considering the state's ownership and financing options for participation in the Alaska Gas Pipeline:

What is the effect of participation on the state's cash flow, its continuing ability to pay for essential public services, and financial integrity and creditworthiness.

Would state participation create additional risks for the completion and operation of the project; cause the project to be completed and to operate successfully; and help or hinder other parties participating with the state or its public corporation or authority in the completion and operation of the project.

Based on ideas offered by during interviews for this report, the Commissioner of Revenue added the following additional evaluation criteria:

- Whether ownership in the pipeline would provide additional information that would be helpful to the state in maximizing its royalty share of gas production or other state revenue.
- Whether there would be a conflict between (1) state ownership in the Alaska Gas Pipeline and the associated motive to maximize returns, and (2) the state's role and responsibility to regulate pipeline construction and operations

Each of the identified ownership and financing options is evaluated against these criteria in Sections 5 through 8. Conclusions are summarized in Section 10.

SECTION 5

Evaluation of Financing and Ownership Options

The state has numerous options for financial participation in the project, including:

- Contributing capital as an equity investment for all or part of the project cost.
- Making capital available through or as a debt investment for all or a portion of the project cost.
- Guaranteeing debt.
- Making in-kind contributions.
- Combining one or more of the above options.

This section reviews and analyzes each of these options in detail and discusses the financial benefits and drawbacks to each.

Financial Participation Options and Analysis

The source of funding is a key factor in determining whether the state should participate by taking an equity position in the Alaska Gas Pipeline. The funds must be available when needed and, of equal importance, must be legally authorized for use as such an equity investment. Use of any of the state's pools of money will have opportunity costs to the state.

The state has a variety of sources for providing capital, including using money on hand or borrowing it. Potential sources of cash include the state general fund, Constitutional Budget Reserve Fund, Permanent Fund and Earnings Reserve Account of the Permanent Fund. Sources of debt include the proceeds of general obligation or revenue bonds or certificates of participation. At a minimum, legislative authorization would be required to tap any of these funding sources and, as discussed below, some of these sources are more plausible than others.

Timing of Capital Calls

Evaluating whether to invest a particular fund in a gasline project involves practical considerations such as the anticipated timing of the project and volatility of the cash stream from a natural gas pipeline of a project size never before constructed in this country. Regulatory approvals for the project would require a minimum of two to three years, with construction expected to take an additional two to three years. Thus, the earliest the project could be moving gas to market would be late this decade, perhaps seven years after the decision is made to go ahead with the project. The analysis in Section 7 is based on the assumption that the Alaska Gas Pipeline would be operational in 2009.

The state's cash requirements for the project would commence almost immediately and increase in size and frequency as work progresses. Initially, any investment would likely require that the state make an immediate, initial contribution to the existing partners to "buy in" to the project (we assume not on a "promoted" basis, where the state would be required to pay a premium over a pro-rata share of the actual investment). It is difficult to predict the size of this initial investment. However, assuming the project sponsors have spent $200 million before the state joins the venture, and the state were able to take a 12.5 percent equity position in the partnership, the initial equity contribution would be $25 million.

For the first few years, the joint venture's capital calls likely would be relatively small, considering the size of the project as a whole. However, once construction begins, the number and size of capital contributions would increase dramatically (ranging up to an annual contribution of nearly $300 million (2001 dollars) for a 12.5 percent stake). Further, depending upon the skill of the project's budget forecasters and the ability to minimize cost overruns, the size of ongoing funding requirements would be difficult to plan for.[11] Another concern would be whether the line started flowing on schedule—particularly if the state needed the revenue to cover the debt it had issued for its investment in the project.

The point is that in order to participate in this project, the state would be required to make significant calls upon its available funding sources and credit for a number of years before the gasline would turn a positive cash flow. Even the first year or so of the of pipeline's

[11] Another complicating factor will be whether and how the project is financed.

commercial life, which may or may not begin as forecasted, likely would not show strong or even positive cash flow due to the typical start-up issues all new pipelines face.

Thus, the source of the state's project funding would need to fit the following profile:

1) It must be immediately available.
2) It must be capable of making large capital contributions without delay and without any expectation of repayment for at least seven years, assuming the project is completed on schedule.
3) It must have the flexibility to timely meet significant and sometimes unpredictable capital calls.

It is also important for the state to keep its risk exposure to a minimum because a state government does not maintain a net worth to absorb serious losses. In this respect, it is unlike the corporate participants in the project. Losses sustained by the state would eventually have to be paid for through reduced services or higher taxes upon the citizens. Losses also could lower the state's bond rating, which would drive up the cost of borrowing for all kinds of public projects, including local schools.

Sources of Equity Funding

As discussed below, the legislature could consider a number of existing state funds as sources of funding for an Alaska Gas Pipeline.

The General Fund

In theory, the state could decide to appropriate unrestricted funds directly from its general fund to pay for its investment in the Alaska Gas Pipeline. Although it is ultimately a political question, there are practical problems with this approach. The general fund currently operates at a deficit and this status is not expected to change within the next few years. The state already has numerous calls on the limited money available within the general fund and it would be difficult, therefore, for the state to impose new taxes or cut public services to the extent necessary to make money available for an equity contribution to the project.

Permanent Fund Direct Investment

There are several ways the Permanent Fund might be able to invest in the gasline project. As a passive investor it might, under the proper conditions: (1) invest in the stock of a company or companies owning the gasline; (2) invest in the bonds used to finance the project; or (3) participate in a private equity limited partnership that finances some portion of the project. However, if the proposed investment were structured so that the Permanent Fund became actively involved in the gasline business, it lacks the legal authority to make such an investment.

The Permanent Fund, the state's major savings account, was created in 1976 by constitutional amendment. A specified portion (at least 25 percent) of the state's mineral lease rentals, royalties, bonuses and federal mineral revenue-sharing payments are dedicated to the principal of the fund.

The constitutional amendment establishing the fund placed one restriction on how the fund was to be invested: It must be invested in income-producing assets specifically designated by law as eligible for Permanent Fund investments. The legislature passed comprehensive legislation in 1980 specifying a list of permitted investments and establishing the Alaska Permanent Fund Corporation as an independent state agency to manage the fund's assets. This legislation declared the Permanent Fund to be an inviolate trust to be managed by the Board of Trustees according to a version of the Prudent Investor Rule often referred to as the Prudent Expert Rule.[12]

The legal list governing permitted investments has been amended several times, and allowable investments include mortgages, real estate investments, certificates of deposit, term deposits or bankers' acceptances, and interests in domestic and non-domestic companies.[13] There are other limitations, too. This statutory list also places a 5 percent limit

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[12] The Prudent Investor Rule as applied to investments of the fund means that in making investments the board of trustees shall "exercise the judgement and care under the circumstances then prevailing that an institutional investor of ordinary prudence, discretion, and intelligence exercises in the management of large investments entrusted to it not in regard to speculation but in regard to he permanent disposition of funds, considering probable safety of capital as well as probable income." AS 37.13 120 (a).

[13] AS 37.13.120

on the amount of voting stock the fund may own of a single corporation. And, domestic stocks owned by the fund, with some exceptions, must be listed at the date of purchase on an exchange registered with the federal Securities and Exchange Commission.[14]

Another requirement in statute is that the board must favor in-state investments if the risk and return are equal to the alternative investment opportunities.[15]

The legislature also adopted a 5 percent "basket clause," which allows the trustees to invest up to 5 percent of the fund's total assets in "other types of investments not specifically listed," so long as the Prudent Expert Rule is satisfied.[16]

Considering all of the above limitations in statute, could the state use the investment authority of the Permanent Fund to go into the gas pipeline business as a partial or 100 percent owner of the project? Without a change in the laws governing the investment authority of the Permanent Fund, the answer is "no." Although the Permanent Fund currently lacks the authority to invest as an active participant in a North Slope gasline business, the legislature could amend the statute and specifically direct the Permanent Fund to make such an investment.

It would be different, however, if the Permanent Fund were simply buying stock or investing in bonds issued by a corporation or corporations that own the gasline. The Prudent Expert Rule requires the trustees to weigh risk and reward and consider investments within the context of the fund's overall asset allocation, while avoiding the concentration of investments in single entities. To comply with the rule, the trustees follow a detailed decision-making process that includes adopting an annual asset-allocation policy and selecting specialized managers to achieve a balanced, diversified portfolio. Under the available investment authority and the constraints of the Prudent Expert Rule, the trustees might well be able to make limited investments in either the equity or the debt of a North Slope gasline enterprise.

Finally, legal question exists as to whether a gas pipeline project that would not produce income for a period of years would qualify as an income-producing investment under the law

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[14] AS 37.13.120(l)

[15] AS 37.13.120(l)

[16] AS 37.13.120 (k) (1).

and whether the constitutional limitation would permit such an investment. We understand that the trustees believe this specific limitation would not preclude this kind of equity investment in a gasline project, but there is no specific legal ruling on the income-producing issue.

Earnings Reserve Account of the Permanent Fund

If the legislature decided it would be in the Alaska's best interests for the state or an independent state corporation to enter the North Slope gasline business, it could appropriate money from the Permanent Fund's Earnings Reserve Account (ERA) to a state agency for that purpose.

Income earned on Permanent Fund investments is credited to the ERA and, on June 30 each year, appropriations are made from the ERA first for dividends to residents of the state and then for inflation proofing of the Permanent Fund's principal. Any undistributed income remaining in the ERA is available to cover future dividend or inflation-proofing needs. The legislature also may appropriate money from the Earnings Reserve Account at any time for any purpose. To date, however, it has never appropriated the money for anything other than dividends, inflation proofing or to increase the principal of the fund.

The Department of Revenue anticipates that the amount of surplus earnings available from the Permanent Fund each year over the next decade will average about $250 million. However, the actual amount available in any one year will vary enormously—ranging from $0 to more than $500 million, depending on the performance of the financial markets and the mechanics of how the surplus is determined.

However, one must remember that the only vehicle the Permanent Fund has to absorb volatility in its investment income is the ERA. Committing the Earnings Reserve to the gas project might jeopardize the Permanent Fund's ability to pay dividends and inflation proofing. And, considering Alaska's general fund deficits, bond rating agencies might view such a commitment unfavorably.

In summary, appropriations from the ERA could be a source of funding for the project. This course of action, however, presents a number of obvious economic and political risks.

Actual and projected Permanent Fund principal and Earnings Reserve Account balances are shown in Figures 5-1 to 5-3, as are the month-to-month fluctuations in the ERA balance.

Figure 5-1

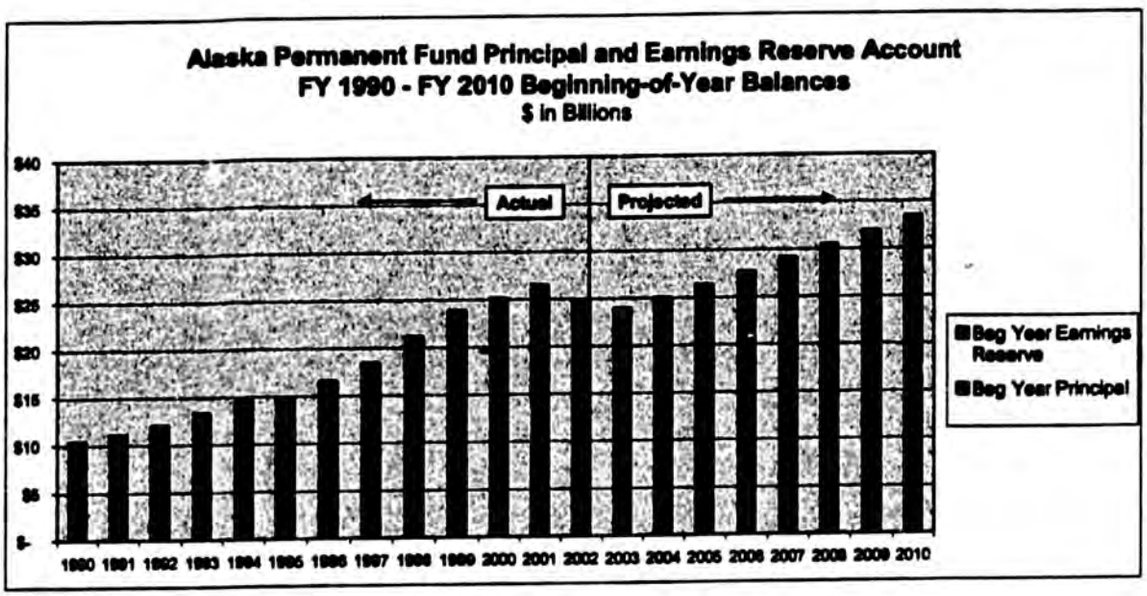


Figure 5-2

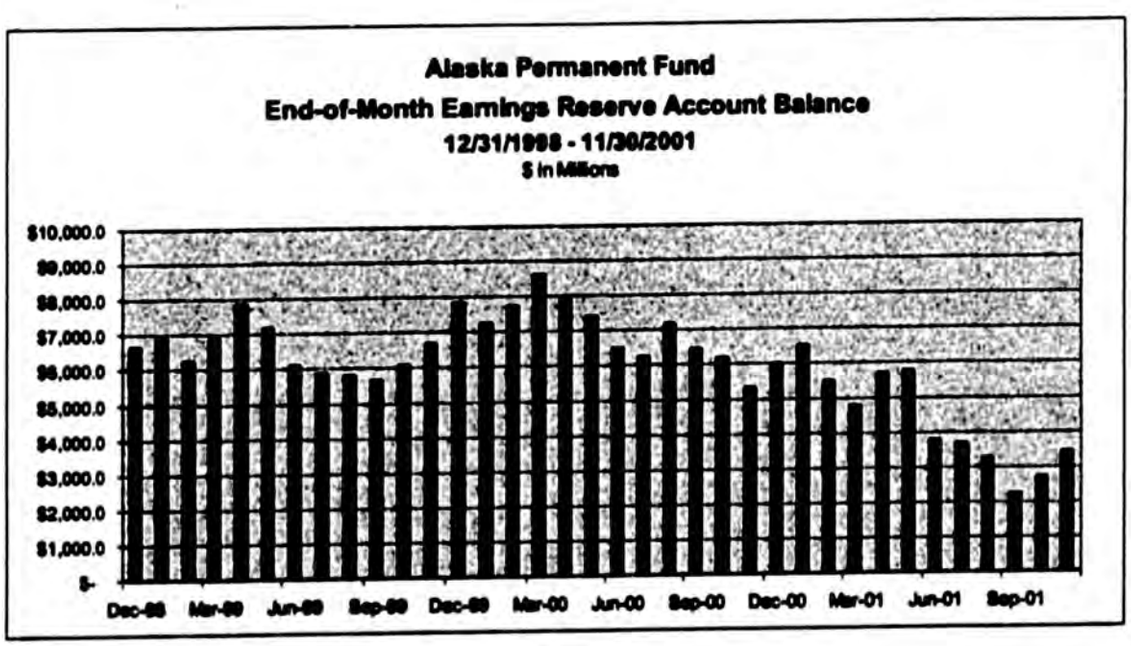
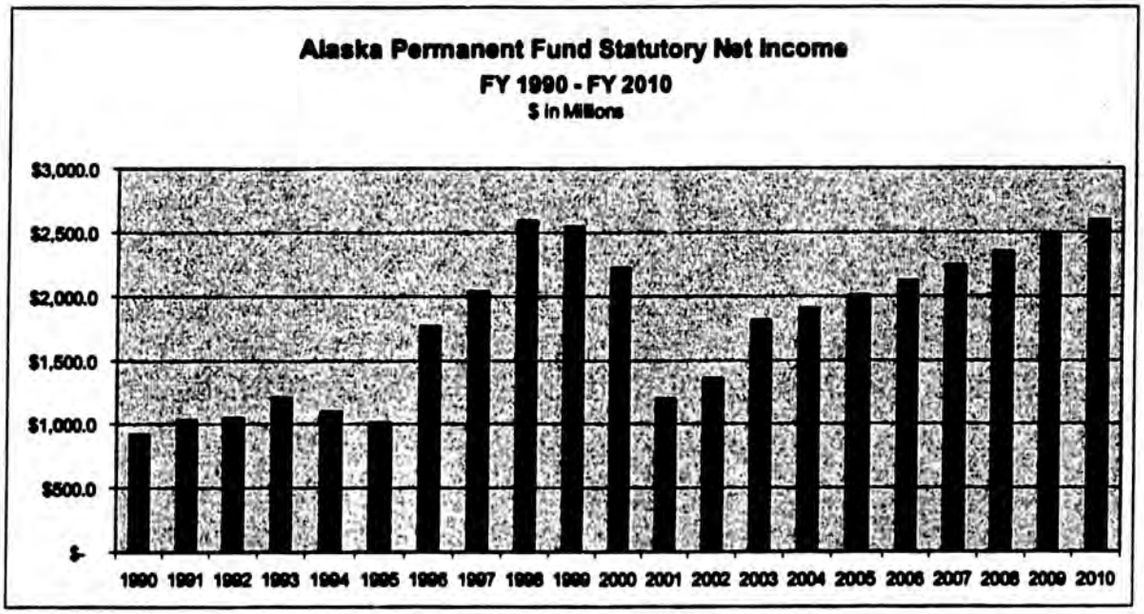


Figure 5-3

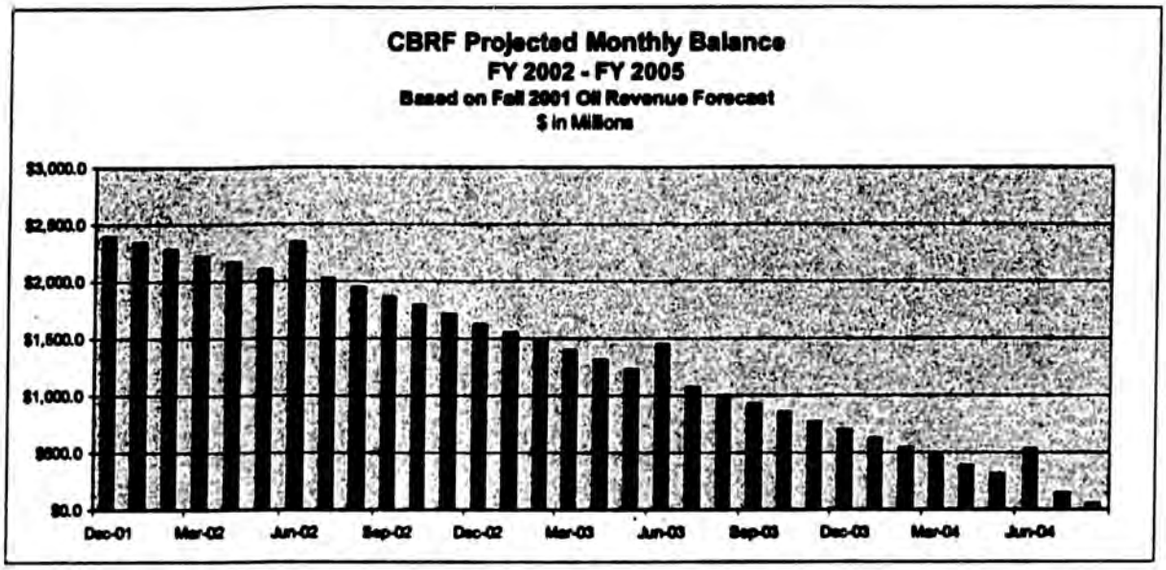


Constitutional Budget Reserve Fund

Created by the voters in 1990, the Constitutional Budget Reserve Fund (CBRF) holds the proceeds from settlements of oil and gas tax and royalty disputes since July 1, 1990. It generally requires a three-quarters majority vote of each chamber of the legislature to withdraw money from the account. For all but two years since 1991, the state has relied on the CBRF to fill the difference between unrestricted general purpose revenue and the annual state budget. Over the past 10 years the state has deposited about $5.5 billion into the CBRF, earned about $1.5 billion from investments, and withdrawn more than $4.3 billion to pay for public services—leaving a balance of $2.65 billion on January 1, 2002.

The projected declining balance of the CBRF is illustrated in Figure 5-4.

Figure 5-4



Note: The $300 million peaks in June are caused by repayment of the beginning year draw.

A fundamental problem with using the CBRF as a potential source for equity investment in the project is that the Department of Revenue forecasts the CBRF is likely to be depleted by late summer 2004 due to declines in unrestricted general fund revenue.

Given the uncertainty of any remaining balance in the CBRF after Fiscal 2004, and the potential negative reaction by bond rating agencies to using this fund for purposes other than covering annual general fund deficits, the CBRF is not a viable source of equity funding for the project.

In-Kind Contributions

Some have suggested that another source of equity for state investment in the Alaska Gas Pipeline could be in-kind contributions from income-generating items like right-of-way lease payments or advance sales of state royalty income. Even if the state was willing to forego the steady revenue benefit of such income, there is a significant problem with the in-kind concept. Using these funds this way likely would violate the dedicated-funds prohibition in

Alaska's Constitution.[17] As a result of this constitutional limitation, the proceeds of state taxes and licenses generally are prohibited from being deposited anywhere but the general fund and the Permanent Fund.[18] If the legislature wished to pursue this alternative further, review by the Attorney General's office would be appropriate.

In any event, with respect to right-of-way lease payments only, it is not expected that the payments would produce enough income to support a "trade" for equity. Although approximately 700 miles of the Alaska Highway Route would be in Alaska and the majority of the route would cross state lands, the state's earnings from right-of-way lease payments would be modest. In Fiscal 2001, for example, the state received only $730,000 from lease rental payments for the 800-mile Trans-Alaska Pipeline System. Annual lease payments from the gasline likely would be similar.

Sources of State Debt Funding

Although an outright appropriation from one of the above sources of state funds does not appear practicable, it is possible the state could structure some type of bond issuance to obtain funds for an investment in the project. The different bonding alternatives are discussed below. The intricacies of coordinating private debt obtained by project sponsors and public debt of the state would be complex and would require further analysis after the gasline funding plan is known. It should be noted, however, that the state would face formidable legal and practical hurdles to financing a significant portion of the project with tax-exempt debt.

There are several types of debt that could be issued, depending on the state's level of commitment. Debt instruments include general obligation bonds, lease-purchase obligations and revenue bonds (with or without state "moral obligation" guarantee). State-guaranteed

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[17] "DEDICATED FUNDS. The proceeds of any state tax or license shall not be dedicated to any special purpose, except as provided in section 15 of this article [establishing the Permanent Fund] or when required by the federal government for state participation in federal programs. This provision shall not prohibit the continuance of any dedication for special purposes existing upon the date of ratification of this section by the people of Alaska." Alaska Const. art. IX, Sec 7.

[18] Lengthy discussions of the dedicated funds prohibition in the context of natural resources revenues, including royalties and bonuses, are found at 1982 Alaska Op. Atty. Gen 13 (November 30, 1982) and 1975 Alaska Op. Atty. Gen (May 2, 1975). Presently, right-of-way revenue is deposited to the general fund. Of royalty and bonus income, 25 percent is allocated to the Permanent Fund, 0.5 percent to the state school fund, and the remainder to the general fund.

bonds are not considered feasible because they would require an amendment to the Alaska Constitution.[19]

The combination of state debt (e.g., general obligation bonds and revenue anticipation notes) and state-supported debt (a portion of University of Alaska debt, lease-purchase financings, and a share of municipal general obligation bonds for school construction) are the measure of Alaska's debt burden used by Moody's, Standard & Poor's and Fitch in assigning a credit rating to state debt obligations. As discussed below, the state's current bonding ability is limited unless the state is willing to accept lower credit ratings.

Today the state maintains favorable credit ratings for its various debt instruments. Its most recent credit ratings were Aa2 by Moody's, AA by Standard & Poor's and AA by Fitch, which are in the high end of debt rating scheduled. However, all general obligation bonds of the state have since been retired (the last in Fiscal 1999). The state's debt rating history is set forth in Table 5-1.

TABLE 5-1
State of Alaska Credit Rating History
(ratings as of date shown)

Moody's Investor Services		Standard and Poor's		Fitch Investor Services	
July 13, 1961	Baa	June 4, 1971	A	May 3, 1994	AA
September 12, 1969	Baa1	January 23, 1975	A+		
August 29, 1974	A1	June 14, 1980	AA-		
June 13, 1980	Aa	August 5, 1992 forward*	AA		
November 26, 1998 forward	Aa2				

* Standard and Poor's has withdrawn its rating of the State of Alaska, as all general obligation debt of the state has been repaid. The state expects to obtain ratings from the three rating agencies in 2002.

[19] Alaska Const. art. IX, sec. 8. The voters did, however, amend the constitution in 1982 to permit the state guarantee of housing loans for veterans issued by the Alaska Housing and Finance Corporation.

General Obligation Bonds

The legislature could authorize the issuance of general obligation bonds to fund a state contribution to the Alaska Gas Pipeline. General obligation bonds, as debts of the state, are backed by the state's full faith and credit. General obligation bonds are the most secure of debt instruments and, therefore, bear the lowest rate of interest. However, general obligation bonds must be ratified by the voters and approved by the State Bond Committee.[20] The state has no general obligation bonds outstanding today (the last were paid off in 1999).

The state has issued general obligation bonds 49 times since statehood, raising almost $1.4 billion. Although there is no statutory limit on the amount of such bonds, the size of a general obligation bond issuance to support this project could be the largest in state history. The largest to date was $200 million issued in 1982. We estimate that a 12.5 percent share of the Alaska Gas Pipeline could require an investment in the range of $1.5 billion, unless project financing is available.

There are legal issues and at least one practical issue associated with the issuance of such bonds in support of an investment in the project. First, the state is precluded constitutionally from lending its credit directly to benefit a private entity.[21] The proceeds of general obligation bonds, thus, could be available to purchase a state equity investment in a pipeline (assuming appropriate statutory declaration of public purpose). The proceeds of such bonds, however, could not be used to make a loan to private investors.

Second, the issuance of general obligation debt to make an equity investment in a joint venture appears to be unconstitutional. The Alaska Constitution states that such bonds may only issued for capital improvements.[22] Issuance of debt to support an investment in a joint venture that would own a natural gas pipeline would not be a permitted use of general obligation bond proceeds because it would not be a capital improvement for public use, but rather an investment in an ownership entity. The proceeds of any general obligation bond issue, therefore, would need to be used solely to acquire an undivided interest in an asset, the

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[20] Alaska Const. art. IX, sec. 8; A.S. 37.15.

[21] Alaska Const. art. IX, sec. 9.

[22] Alaska Const. art. IX, sec 9.

pipeline. This may not be a practical method of structuring the relationship of the other parties participating in the project.

Third, the state's borrowing capacity may be too insignificant to be of any practical assistance to support the investment. The state's borrowing capacity can be measured using generally accepted ratios (as discussed in Section 8 of this report). These ratios represent acceptable norms for issuing debt. It has been state policy to stay within the range of committing 8 percent of unrestricted general fund revenue to debt service, in order to maintain the state's historical AA credit rating.[23] At a limit of 8 percent of the general fund's unrestricted revenue, the state's available maximum general obligation bond capacity ranges from about $210 million of 10-year bonds to approximately $300 million in 15-year bonds.

However, investors have recognized the shift over time from when most state revenues were unrestricted to today, when a significant portion of revenues are restricted by the state's direction. That is, the state has segregated money into various funds that create restricted revenues rather than unrestricted—the largest of which is the Permanent Fund. If we add Permanent Fund earnings (after inflation proofing) to the state's unrestricted revenue and take 8 percent of that, the state's available debt capacity would jump dramatically—about $1.2 billion of 10-year bonds to $1.7 billion in 15-year bonds.

Nevertheless, any new issuance of state debt (especially if it relies on restricted revenues for debt capacity purposes) would be carefully reviewed by the rating agencies due to the state's uncertain fiscal situation. A proposal by the state to exceed its current debt service thresholds would need to be carefully reviewed for presentation to the rating agencies in order to avoid a downgrade.

State-Supported Debt

State-supported debt is debt for which the ultimate source of payment is, or may include, appropriations from the state general fund. The state's full faith and credit is not pledged

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[23] Debt service, for determining debt capacity, includes debt service on general obligation bonds, University of Alaska bonds that are state supported, state reimbursement of municipal school debt, and lease payments on lease purchase financing.

[24] Since 1998, the largest taxable general obligation bond issuance was by the City of New York for general purposes and public improvements in the principal amount of $434.1 million. Source: Thomson Financial.

against the debt, and state-supported debt is not considered state-guaranteed debt for purposes of the Alaska Constitution because the state's payments on the debt, even if the subject of a contractual commitment, are contingent on annual legislative appropriation. As a result, citizen approval of such debt is not required—although legislative approval is required in almost all instances.

The form of state-supported debt that might be useful in this project is lease-purchase financing obligations consisting of certificates of participation (COPs) issued by lessors of facilities used by the state. In such situations, generally the debt is secured by the lease payments on the leased facilities.

The limitations inherent in this type of financing are similar to those associated with general obligation bonds, except that no public vote is necessary. This debt also would not be tax-exempt, and the state has limited capacity without jeopardizing its credit rating. Further, the complexity inherent in structuring a financing of this magnitude as a lease is substantial. The state probably would lack sufficient debt capacity to lease the entirety of the pipeline to the project sponsors.

Revenue Bonds

Probably the more likely source of debt financing would be through the issuance of some form of revenue bonds. These most probably would take the form of bonds issued by a state agency and secured by revenues generated from the use of the pipeline, such as ship-or-pay contracts for moving gas through the line. In the most customary form of revenue bonds, the project and its revenues constitute the sole source of repayment of the revenue bonds. Private corporate guarantees and letters of credit also could provide additional security.

In a separate type of revenue bond, additional security would be obtained from a reserve fund that includes a discretionary capital reserve provision. A typical capital reserve fund is approximately equal in size to the maximum amount of debt service required in any year. If the reserve fund falls below its required level and if a moral obligation concept were applied, the legislature may, but is not legally required to, appropriate funds sufficient to restore the capital reserve fund (in other words, the state has a "moral obligation"). The authority to issue moral obligation revenue bonds is contained in the enabling legislation of several state

agencies such as the Alaska Energy Authority and the Alaska Industrial Development and Export Authority.

The revenue bond concept is not new to this project. Authority for revenue bonds was approved for the Alaska Pipeline Financing Authority in 1978. In its enabling legislation, the Financing Authority was authorized as a conduit to issue revenue bonds up to the principal amount of $1 billion, inclusive of amounts required for capital reserves, for the purpose of purchasing or otherwise acquiring any obligation issued with respect to the ANGTS project—provided that the payment on that obligation was fixed and certain as to terms of repayment. Debt service on the bonds was to be paid from the income and receipts derived from the project. The bonds were expressly not debt of the state or any political subdivision, and were to be paid exclusively from the project income. The state pledged that it would not limit or alter the rights and powers vested in the Financing Authority to fulfill the terms of any contract made with the bondholders or in any way impair the rights and remedies of those holders unless the bonds were fully paid and discharged.[25]

Revenue bonds are not a general obligation of the state, nor does the state provide security for the debt in any other manner except in the case of "moral obligation" pledges. Depending upon the other available security, a "moral obligation" could provide additional credit enhancement and lower interest rates to traditional revenue bonds.

Alaska Gasline Port Authority Financing Proposal

As described in Section 3, the Alaska Gasline Port Authority has proposed an innovative plan to finance a pipeline from the North Slope and an LNG facility at Valdez, along with an additional line branching away at Delta Junction to carry natural gas to the Canadian border to connect with the Lower 48 grid. The Port Authority proposes to finance 100 percent of the costs with a combination of tax-exempt and taxable revenue bonds. Based upon legal and financial analysis and an IRS letter, the authority believes its *income* would be tax-exempt.[26] Since the letter application to the Internal Revenue Service is not available, it is not clear whether the ruling is based upon all of the relevant facts.

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[25] AS 44.82.150, repealed 1994.

[26] Private Ruling 200017018 (January 27, 2000).

First, according to the IRS response, the Port Authority represented that the authority's revenues would be derived primarily from the sale of natural gas to municipalities within the state and to other purchasers expected to include governmental and private enterprises. But the vast majority of the authority's revenues would, in fact, be derived from sales of natural gas outside the state.

If the underlying facts have not been fully or accurately described in the letter to the IRS, the IRS is not bound by the ruling and it may not be relied upon.

Second, there may be an issue regarding the fact that the Alaska Constitution does not specifically authorize port authorities to exist as political subdivisions of the state, and only the state or a political subdivision may issue tax-exempt bonds.

It is generally more expensive to borrow money without any equity commitment because 100 percent debt financing—the absence of any owner contribution whatsoever, such as buying a house with no down payment or other collateral—increases the risk to creditors of not recovering the entire debt. Thus, 100 percent debt financing for the project, if it is available at all, could come at a relatively high cost. This high financing cost could negate all or a portion of the relatively limited benefits attributable to the port authority structure.

The Port Authority claims that it would be exempt from federal income taxes for the amount of income it retained for itself (estimated by the Port Authority at $37 million per year) and the amount it remitted to the state and other municipalities (estimated at $333 million per year). This income would come from the "profit" earned by the Port Authority on the difference between what it paid the producers for the gas and what it was able to earn by selling the gas and LNG on the world market. This income tax savings could be seen as a benefit to the project. The foregone tax would be about $130 million per year, according to Department of Revenue estimates.

A few comments on the practical considerations of the Port Authority plan also should be made. The Department of Revenue and its consultants are unaware of any LNG terminal facility, gasification facility or natural gas pipeline in the world that has obtained 100 percent debt financing. LNG facilities with up to 75 percent debt have been constructed, but they are the exception—something in the range of 60 percent to 70 percent is more common. The

hurdles to obtain even this level of financing is high, with lenders generally requiring the following to be in place just for a "conventional" project financing of a LNG terminal:

- A long-term LNG sales agreement with creditworthy purchasers for a minimum base load.
- Long-term natural gas supply agreements with creditworthy suppliers for a minimum volume.
- Acceptable quality and quantity of proven gas reserves.
- Liquefaction capacity sufficient to meet the project's sales obligations.
- Fixed-price or minimal determinable price contracts.
- Long-term transportation agreements with sufficient capacity to meet delivery schedules.
- Capped marine freight price.
- An experienced shipbuilder if transportation is via a new tanker.
- Experienced vessel owners and operators.
- Proven technology.
- Fixed-price, date-certain engineering, procurement and construction contracts with experienced, creditworthy contractors.
- An appropriate framework among creditors to harmonize force majeure provisions and other potential contractual issues.
- A cash-flow allocation to allow each project access to appropriate payment stream.
- Adequate payment security mechanisms such as escrow accounts and letters of credit.

The prerequisites for financing a natural gas pipeline are similar. Some of the requirements listed above for an LNG facility can be met by the Port Authority, but it still faces formidable challenges to satisfy others. For example, obtaining gas supply commitments from North Slope producers and suitable off-take agreements from purchasers seems unlikely for a variety of reasons, including:

- Their lack of interest in LNG exports from Alaska.
- Their involvement with gasline proposals they believe are more commercially viable than LNG.
- The question of what happens when the Port Authority gasline gets to the Canadian border.
- Their concerns about doing business with an entity controlled by municipalities.

Other Financial Participation by the State

State Loans to Project Sponsors

If funds are available, loaning money to the project may be a more desirable alternative for Alaska than equity participation due to a stronger claim on revenues, lower construction and operation risks, and fewer conflicts of policy interests. There are practical limitations on the state's participation, however.

- First, Alaska would need to have funds available to lend to the project. The source of such funds may affect the ability of the state to meet other governmental needs.
- Second, any financial return to the state would be delayed at least until after 2010.
- Third, the debt structure easily could put the state in a minority or subordinate position with little control over the project or its operation.
- Finally, and most importantly, the state's debt likely is not needed by the project developers.

During the interviews, the potential project developers generally indicated they only would have an interest in state financial participation if the state could somehow issue tax-exempt securities. As discussed above, this alternative would probably require an exception to federal tax law. Most of the potential project developers have credit ratings and overall financial resources equal to or more substantial than that of the state (Table 5-2). They likely would be able to obtain attractive interest rates and terms and, accordingly, state taxable debt is not particularly attractive as an alternative. As shown in the following chart describing

common credit measurement factors as of January 15, 2002, the creditworthiness of the potential gasline project sponsors is good to excellent. Further, even though this project is of enormous magnitude, there appears to be adequate debt capacity in world capital markets today to fund it.

TABLE 5-2

Corporate Debt Rating of Potential Project Developers

Company	Senior Debt (SP/Moody)	Debt + Pfd / Bk Cap	Fixed Charge Coverage	Debt + Pfd / EBITDX	Debt + Pfd / DsCF
ExxonMobil	AAA/Aaa	15%	92.6	0.3	0.4
BP	AA+/Aa1	24%	N/A	1.5	2.4
Phillips	BBB+/A3	47%	14.1	0.9	1.4
Duke	A+/A1	49%	7.3	2.9	5.2
TransCanada	A-/A2	72%	2.3	5.1	9.2
WestCoast	A-/ n/a	72%	2.6	7.0	11.3
El Paso	BBB+/Baa2	58%	3.9	3.5	3.9
Williams	BBB+/Baa2	55%	2.3	3.5	9.3

EBITDX = Earnings before Interest, Taxes, DD&A, and Exploration Exp.

DsCF = Discretionary Cash Flow = Net Income + DD&A + Def. Taxes + Exploration Exp. + Other Non-Cash Items

Debt + Pfd / Bk Cap = (Total Debt + Preferred Stock) / Total Book Capitalization

Fixed Charge Coverage = EBITDX / (Interest Expense + Pre-Tax Preferred Dividend)

Direct Guarantees

Even though the creditworthiness of the known project sponsors is high, if there is a shortfall in that respect perhaps the companies might have an interest in the state lending credit support through forms of state guarantees. Generally, the use of a guarantee would be of significant benefit only if the guarantor has a credit rating higher than the rating on any debt issued by the pipeline investors—which does not appear to be the case with the state.

In contrast to direct funding through an equity investment or debt, debt support would not require the outlay of state funds. The guarantee could be provided by either (a) the state directly guaranteeing debt issued by the sponsors, (b) a state authority guaranteeing debt issued by the sponsors, or (c) the state guaranteeing debt issued by the authority, the proceeds of which would then be lent to the sponsors. The state's obligation, in all cases, would be

limited and contingent upon various events as the state could negotiate, such as expiration date, subordination rights, amount, guarantee payment terms, equity conversion rights, etc.

The structures referred to in (a) and (b), however, may require voter action. Further, the Alaska Constitution prohibits the state from directly guaranteeing private debt.[27,28]

Assuming the two hurdles mentioned above could be overcome, there are various forms that an appropriate state guarantee could take. A direct, full-faith and credit guarantee by the state obviously would constitute the strongest credit support the state could make, but this also would be the riskiest for the state. There is the possibility that a guarantee could be structured in a form that is constitutionally permissible. The legislature may be able to set aside a specific category of reserve funds within the general fund or Earnings Reserve Account of the Permanent Fund, for example, upon which to base a limited guarantee. However, this would require further analysis of the Attorney General and, even if legally permissible, would be removing flexibility to meet future fiscal requirements of the state.

Moral Obligation Guarantees

The state may also be able to lend its credit support through pledging its moral obligation in some form of financing structure. Such a moral obligation would not constitute the legal indebtedness of the state and would not, therefore, require action by the voters. Such a structure has won credibility with investors in other contexts where it has been employed because of the perception of rating agencies and investors that the state undertaking such a moral obligation would, if necessary, honor its moral obligation by appropriating funds to meet debt service shortfalls. The failure to do so would be regarded as a derogation of the state's credit and hurt the state's ability to sell its securities.

The moral obligation commitment could be strengthened by earmarking a single revenue source as security for the moral undertaking. Such a structure would involve the legislature appropriating existing revenue to a state authority and then enacting legislation to appropriate

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[27] Alaska Const. art. IX, sec. 8.

[28] In 1982 the voters approved a constitutional amendment that permits the state to guarantee unconditionally as a general obligation of the state the payment of principal and interest on revenue bonds issued by the Alaska Housing Finance

a revenue stream to the authority in future years, subject to the right of future legislatures to reverse such appropriation. Because the legislature is not legally required to appropriate such revenues in any year, such action should not constitute a legal dedication of revenues in contravention of the constitutional prohibition previously discussed. The authority would, in turn, issue debt secured by a pledge by the authority of such revenues and then lend the debt proceeds to the project sponsors. The revenue stream so pledged would not be utilized to pay debt service unless the sponsors defaulted on the loan agreement and, to the extent not utilized for debt payments, the revenue stream would be available in any year for any other purpose designated by the legislature.

Compensation to Alaska for Loan Guarantees

In the event that Alaska decides to extend a limited and contingent guarantee, the state would be entitled to compensation for its undertaking. There are a number of ways such ways such values could be determined in an arms-length negotiation with the sponsors. However, these alternatives are beyond the scope of this report.

Tax Issues

Under existing federal tax law, states may issue tax-exempt municipal bonds for public projects, such as schools. Without an exception to the existing Internal Revenue Code, however, bonds—whether general obligation, revenue or other type—issued to finance a project such as the Alaska Gas Pipeline are likely to be almost all taxable. This debt would be considered "private-activity bonds," and the interest on private-activity bonds, except for those that finance certain exempt facilities and nonprofit enterprises, is taxable.

Debt is classified as a private-activity if it meets certain tests, established under the regulations promulgated under Section 141 of the Internal Revenue Code. The debt must meet both the private-use and private-payments tests. In addition, if the debt proceeds are deemed to have been used to make "private loans," the debt is considered to be private-activity bonds.

Corporation for the purpose of purchasing mortgage loans made for residences of qualifying veterans. This is the only purpose for which state-guaranteed bonds may be issued.

Certain categories of facilities, however, may be eligible for tax-exempt financing. It is possible, though not certain, that certain aspects of this project could qualify for tax-exempt financing as "dock and wharf" facilities, such as a marine LNG terminal.[29] The eligible portion would likely only be a fraction of the entire cost and, therefore, use of this exception would still mean that all or substantially all of the project could be financed only on a taxable basis.

Another exception under federal law is the private-activities cap. Under this cap, each state is allowed to issue tax-exempt bonds for private activities up to certain limits. In the case of Alaska, the limit is currently $187.5 million per year. However, this amount already is fully subscribed each year for debt issuances of the Alaska Industrial Development and Export Authority, Alaska Housing Finance Corporation, Alaska Student Loan Corporation, municipalities and other purposes. The State Bond Committee allocates the annual allowance.

The tax treatment of the debt does not change depending upon the identity of the issuer. Thus, debt issued by a conduit or other state agency is not any more likely to be exempt. In addition, the type of debt also does not necessarily affect its tax status. Tax status depends upon the use of the proceeds and the sources of repayment of the debt.

There is a market for taxable bonds. However, the market for this debt is untested since there have been no comparable issues by other states in the past.[30]

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[29] There has been at least one successful tax-exempt funding of a marine terminal in Alaska. When the state refused in 1974 to support state tax-exempt financing for TAPS, the City of Valdez was considered as a potential issuer for at least the marine terminal facilities. In that year, the voters of Valdez authorized a bond issue of up to $2 billion for financing the marine terminal facility. In 1977, after receipt of an IRS ruling recognizing the tax-exempt treatment of the bonds, the City of Valdez, on behalf of ARCO and with utilization of ARCO's credit capacity, issued $265 million in Terminal Revenue Bonds. These bonds, as all successor terminal bond issuances, were secured solely by the project revenues and the company's credit. The credit of Valdez was not required. The city received a 1 percent impact fee from the financing and began to accumulate the funds in a permanent fund. Subsequently, in 1977, SOHIO undertook the same financing, and by the end of 1978 a total of $1.265 billion of Terminal Revenue Bonds had been issued for each of the various owners of the marine terminal. Since the initial issuance of the bonds, there have been numerous refundings with extensions of bond maturities up to 2037 in some cases. Almost all of the original debt amount still is outstanding.

[30] For example, since 1996 the largest taxable municipal general obligation bond issuance appears to have been by the City of New York for general purposes and public improvements in the principal amount of $434.1 million. Source: Thompson Financial.

Because the state's private-activity cap already is fully utilized—and insufficient to finance much of a state investment in the gasline—and because only a fraction of the project could qualify as a dock or wharf facility, the analysis in this report is based on the reasonable assumption that almost all debt issued by the state for this project would be taxable. Under this assumption, debt participation by the state does not appear economically attractive, because the state probably could not obtain substantially better interest rates than private parties. The state could obtain better interest rates only if it could issue tax-exempt municipal bonds for the project under a special exception to federal law. This option is discussed below.

Tax-Exempt Financing

As discussed above, the state would need a special exception to federal law in order to issue tax-exempt bonds to finance the Alaska Gas Pipeline.[31] Although rare, such special exceptions do occur. Here, a special exception would be predicated on the fact that the pipeline is a unique transportation project that could provide a stable domestic source of energy. Given that the project would serve the important national interest of making the country less dependent on foreign energy, the possibility of tax-exempt financing is worth considering.

If tax-exempt financing were available, what would it look like?

First, we assume the state would issue some form of revenue bond, not a general obligation bond, because a general obligation bond would put an intolerable amount of financial risk on the state.

Second, as required under federal law, the state would be the owner of at least as much of the project as it financed through tax-exempt bonds.

Third, most likely a gasline revenue bond would be in the form of an industrial development bond issued through a state authority such as AIDEA or other special-purpose entity that the legislature might create. The bond would be issued by the authority to finance facilities that are then leased to the private-entity user at a rent equal to debt service on the bonds and for a

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[31] The advantage of the gasline qualifying as a permitted private activity is that the private-activity monetary cap does not apply.

term equal to the maturity of the securities. Alternatively, the issuer might be able to loan the proceeds of the industrial development bond directly to the private-entity user on repayment terms equal to the terms on the bonds. In either form, the responsibility for construction and operation of the project would remain with the private developers.

Fourth, security for payment of the debt would be revenues from the project itself, likely supported by ship-or-pay contracts with the producer/shippers.

Fifth, the financial markets likely would finance no more than 70 percent of the project with this kind of debt. The remaining 30 percent would have to be an equity contribution. Options for the equity financing would be direct state contribution (which could be $3.5 billion to $4 billion on a $12 billion to $14 billion project cost), or a similar contribution from some other party—for example, the producers could be asked to contribute the 30 percent equity share under contract as a prepaid tariff.

If the state were able to provide tax-exempt financing, would it make the Alaska Gas Pipeline more attractive to the private parties whose participation is necessary to get this project off the ground? This question is difficult to answer. Even though there almost certainly would be an economic benefit from tax-exempt financing, whether the resulting structure is attractive to the producers or pipeline companies is an open question.

A financial analysis of the benefits of tax-exempt financing would have to consider many variables. One of the most important of these is the spread between tax-exempt interest rates and taxable rates. Usually this spread will be around 25 percent (such as 8 percent for taxable bonds and 6 percent for tax-exempt), but it can vary with market conditions and may be different for a project like this.

A second consideration is the value that a private owner gives up when the state takes over ownership of the project. Primary among these foregone benefits is the right to depreciate the asset. The value of this benefit over time to a company will depend on the company's tax rate and its discount rate—i.e., the value it places on having money today rather than in the future. If the producers owned the pipeline, the tax law would allow them to claim accelerated depreciation, under which they would be able to deduct the cost of the pipeline from their taxable income over 16 years, with larger deductions occurring in the first six

years.[32] In addition, they could deduct their interest payments. If the state owned the pipeline, the producers could only deduct the cost of their lease payments to the state. Over time, they would deduct roughly the same total that they would have deducted had they owned the project, but it would take much longer to realize the economic benefit of the deduction without the use of accelerated depreciation.

Because of the time value of money, the accelerated depreciation payments allowed under a private-ownership scenario would reduce the economic benefit of tax-exempt financing. In the early years of the project, a private owner would be better off with taxable financing. One attempt to model the cost advantage of tax-exempt financing for a typical producer shows that, under one set of reasonable assumptions, tax-exempt financing is economically advantageous, but it would take 13 years for an owner to realize a cost advantage from tax-exempt financing.

In sum, unlike the other options discussed in this report, tax-exempt financing might make feasible a project that otherwise would be uneconomic. Alternatively, the state might be able to extract an additional state benefit if it were to provide tax-exempt financing to lower the costs for an already profitable project. Since tax-exempt financing does offer financial benefits, the state may consider supporting a federal effort to obtain a tax-exemption for state debt for the project.

Even if tax-exempt financing were an option, however, it is not certain that the sponsors of the Alaska Gas Pipeline would prefer that option. That would depend on the resulting ownership structure and actual savings to the sponsors over their own costs of capital and foregone benefits such as depreciation.[33]

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[32] 26 U.S.C. § 168.

[33] If any portion of the state's equity funds originated from proceeds of a tax-exempt bond, this structure could jeopardize the use of accelerated depreciation by the private entities for the entire project. Under a worst-case scenario, the entire project would be required to use 125 percent of useful-life and straight-line depreciation.

Ownership Alternatives

SB 158 requires the Department of Revenue to consider specific forms of equity investment in the project. There are two major alternatives: direct state ownership or establishment of a public authority such as the Alaska Industrial and Export Development Authority (AIDEA). The bill also requires the department to consider the merits of a private corporation comprised of Alaska residents who wish to invest in the project. This corporation would own a portion of the project and/or assist in its construction and operation. These alternatives are discussed below.

Direct State Ownership

The state owns and has financed a variety of public facilities. Although there is no direct constitutional impediment in Alaska to a public/private joint venture, the use of public/private partnerships historically has not been an ownership mechanism for state facilities. However, it is an option for non-public facilities, as occurred in December 2000 when AIDEA took an initial equity stake in Alaska Seafoods International, an Anchorage seafood processing company. AIDEA obtained a larger equity stake in the corporation the next year after the state authority helped restructure the business, which faced a severe cash shortage. Although we are not aware of any situations where the state itself—rather than AIDEA or another agency—directly owns a part interest in a private venture, we also are unaware of any specific legal prohibitions to such a structure.

However, as mentioned in the discussion above, it is important to note that the state is precluded, by the Alaska Constitution, from "lending its credit directly to benefit a private entity." We do not believe that would necessarily prevent the state from taking a stake in a private partnership, as long as the state could show it was not lending its credit to the private entity.

Public Authority

Funneling the state's investment through a public authority would avoid some of the problems of direct state ownership. A public authority would provide a one-step removal from direct involvement of state government with a private company. With an independent

board of directors and executive director (albeit possibly appointed by the governor and even confirmed by the legislature), and statutory provisions that provided the authority with a degree of management independence, an independent authority could act and react more like a private business entity.

The creating legislative enactment could provide an authority with independent corporate powers, bond issuance and credit guarantee capacities, and the ability to engage independently in federal programs. A separate legal authority also could maintain a degree of separation from the customary political process associated with state government and establish a clearly dividing line for liability. The assets delivered and pledged to the authority could be the only public assets available to satisfy claims against the project, possibly shielding the state from any potential damages.

Private Corporation of Alaska Citizens

Alaska could participate in the ownership, construction or operation of a gas project by creating a private corporation expressly for that purpose. It may be possible, moreover, to devise strategies that leave most of the shares of the corporation in the hands of state government and its citizens. The approach nevertheless raises a number of questions that should be addressed before it is seriously considered.

This concept was proposed in a report prepared for the state in 1978 by Dillon, Read & Co. It was modeled upon the structure of the Alberta Energy Corporation (AEC), which at that time was owned in part by the government of the Canadian Province of Alberta. AEC was capitalized initially by the provincial government with an investment of $75 million. Subsequently, in 1975, Alberta offered shares worth an additional $75 million publicly. Provincial residents, however, were given a priority during the first three weeks of the offering. All of the shares were sold during the priority period, so afterward AEC had a total capitalization of $150 million, with 50 percent of the corporation owned by Alberta residents and the other 50 percent owned by the province.

The Dillon, Read report suggested this model as a possible approach for Alaska, based on the assumption that funds used for the state's initial equity investment in the corporation could be obtained by issuing tax-exempt general obligation or revenue bonds. Under existing law, a

private (non-governmental) corporation may not issue tax-exempt bonds, except in compliance with certain Internal Revenue procedures for non-profit corporations.

Several things have changed since the Dillon, Read report was issued. Over the years, the Alberta government has extricated itself from its ownership of AEC. The province divested the last of its shares in 1993. And, more noteworthy, U.S. tax laws changed dramatically in 1986. As a consequence, bonds used to raise funds to capitalize a private corporation would, almost certainly, not qualify as tax-exempt.

This approach of a private corporation raises a number of issues. For example, attempting to limit shareholders exclusively to Alaska citizens may present practical problems and perhaps even legal ones. As a practical matter, a residency requirement for shareholders may be difficult to monitor and enforce. It almost certainly would diminish the market value of the corporation's shares. And, as far as the U.S. legal system is concerned, this concept may be unprecedented. We are not aware of any state forming a private corporation, whose shareholders are limited to state residents, in order to advance a development project in the state. Legal challenges to this approach are therefore possible. Among other things, the validity of the residents-only shareholder's rule might be challenged as lacking a legitimate public purpose. The restriction also might be challenged under the Privileges and Immunities Clause of the U.S. Constitution[34]—which essentially guarantees equal treatment among citizens by state governments—notwithstanding the "private" nature of the corporation. Before following this approach, a thorough analysis of questions like these would be advisable.

More significantly, this approach fails to offer any tax or financial advantage over the development of a project by existing private corporations. As previously mentioned, the tax code underwent significant revision in 1986, and Dillon, Read's assumption in 1978—that the state could issue tax-exempt bonds to raise funds for the initial capitalization of the corporation—is no longer valid.

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[34] ..."No state shall make or enforce any law which shall abridge the privileges or immunities of citizens of the United States"... U.S. Const., Amend. XIV, sec. 1.

It is also difficult to see what advantages this approach provides over other, more readily available, alternatives. Providing Alaskans the opportunity to hold shares in the project, by itself, would appear to be an insufficient justification, because Alaska and its citizens already can hold shares in the corporations with an interest in developing North Slope gas. A new, state-sponsored corporation is highly unlikely to offer a "smarter" option for development, because existing corporations with experience building and operating large gas pipeline projects are likely to build and operate the North Slope project better, for less.

The potential upside from participating in this project is not extraordinary, because the earnings on the corporation's gas pipeline investment would be regulated by FERC.

And participating in order to influence the pipeline route is unnecessary, since Alaska law already forecloses the Over-the-Top Route.

Due to the size and scope of this idea, if the legislature wishes to pursue it further we recommend that special tax, securities and investment banking advisers be retained.

The preceding concerns, of course, are not exhaustive. Using state revenues to form a gas pipeline corporation would further concentrate the state's—and, therefore, its citizens'—investments toward oil- and gas-related activities, while diversification away from such activities may be a more prudent investment strategy for a state already so dependent on oil and gas.

In addition, the new corporation presumably would borrow most of the funds necessary to build the project or its share of the project. But lenders would require long-term, ship-or-pay commitments from the major North Slope gas owners before they would be willing to risk their funds. These gas owners, however, would not enter long-term, ship-or-pay commitments in support of a project (other than one they themselves sponsor) unless (1) they conclude that the project as a whole is economic, and (2) they believe the project sponsor can build the project and operate it reliably at a lower cost.

make it certain that the sponsor would need to revise the ANGTS option from the approved proposal. In addition, FERC "is likely to be required to conduct additional environmental analysis." ANGTA gives FERC "broad authority to amend" the certificate if it does not result in change in "the basic nature and general route of the approved transportation system." Although FERC is unlikely to adhere strictly to conditions that are no longer practical or technologically optimal, it is not clear how much latitude either the project sponsor or FERC has to revise the ANGTS without further congressional action.

- There appears to be nothing in ANGTA that prevents FERC from considering, under the Natural Gas Act, other proposals filed by other sponsors or routes different from the ANGTS route. However, limitations placed by the ANGTA on such FERC considerations are unclear and might also require clarification from Congress.

Major Regulatory Issues for Transporting Alaska Gas—2002 and Beyond

Open Access

U.S. pipelines are built when their sponsors obtain and accept a Certificate of Public Convenience and Necessity from FERC under Section 7 of the Natural Gas Act. Canadian pipelines need similar certificate authority, usually from the National Energy Board (NEB). To move gas from Alaska, multiple jurisdictions would exercise regulatory authority, however, the primary regulatory authorities would probably be FERC jurisdiction within Alaska, NEB jurisdiction within Canada, and FERC jurisdiction again downstream to ultimate markets in the United States.

To construct a multi-jurisdictional pipeline and get it financed in a timely manner requires regulatory approvals, a known and agreed-upon tariff structure, an approved pipeline route and set of initial rates, and transportation agreements that have a term and volume to allow financing and that mirror each other by jurisdiction and in receipt and delivery point. Each section of an integrated, multi-jurisdictional pipeline needs to have understood contract terms that match adjoining upstream and downstream facilities. This includes transportation volumes (size of pipe), gas quality standards (type of gas), known tariff structure (the cost to move the gas from Point A to Point B), and simultaneous service. Each piece of the pipe

must be operational concurrently, must physically be capable of moving the volumes nominated by its shippers or upstream pipeline, and be able to deliver like volumes into downstream pipelines or to downstream customers. The contract volumes, terms, and titles need to match. As noted above, under ANGTA, these issues were largely negotiated as part of the supply arrangements assumed by the pipelines. In today's world, this might not work.

Open Season Processes

In a world after FERC Order 636, pipelines need to use a nondiscriminatory process to solicit contracts for transportation service. This is true both for a new pipeline and for expansion of an existing pipeline. Typically this is done through a so-called "open season" solicitation. The open season announces the intention of a pipeline company to build new facilities based upon an expression of interest by parties willing to contract for service on those new facilities.

The open season can be done in a variety of ways, but generally it leads to a process yielding binding transportation agreements of a term and volume adequate for regulatory approval of a certificate to construct and for ultimate financing approval. This means that all parties are given simultaneous equal opportunity to "bid" for pipeline space under a clearly defined set of time frames and rules. Ordinarily bidders must meet minimum standards (including demonstration of credit support) to be awarded transportation space.

For a multi-jurisdictional pipeline such as an Alaska pipeline project , the combined project would need to "perfect" contract support for each leg of the pipeline (i.e. Alaska, Canada, Lower 48 states) to allow a complete, coincident contract path for the cumulative volumes. ANGTA did not contemplate an open season process or a Section 7 NGA filing, because the filing authority was ANGTA itself. It is not evident how these issues would be resolved. The manner by which firm capacity would be obtained for the Alaska pipeline and its alignment with existing downstream pipeline firm capacity is unclear. This might be the most significant issue surrounding the economic and commercial viability of building these pipeline facilities.

Tariff

ANGTA contemplated a cost-of-service tariff, common in the period leading up to the ANGTA negotiations. Under this type of tariff, the cost of gas and the cost of owning and operating a pipeline is computed monthly and billed to customers of the pipeline. All costs including return are periodically reviewed for reasonableness, and cost of capital and capital structure are reviewed in periodic rate proceedings, as prescribed in Section 4 of the Natural Gas Act. Within ANGTA, an incentive rate-of-return feature was included to recognize the risk and cost of the formidable undertaking involved in a project to move large quantities of Alaska natural gas such a great distance to market. The concept involved a 50-basis-point risk premium on the equity return.

This type of cost-of-service tariff is now used less and less frequently both in the United States and Canada. Within the United States, tariff design has moved toward a straight fixed variable (SFV) rate design. This tariff approach does not have monthly cost adjustments. There is no longer a requirement for periodic rate filings under Section 4, and rate proceedings are generally the prerogative of pipeline owners or can be initiated by other parties under Section 5 of the NGA. Because most costs are fixed, the primary basis for cost recovery is a fixed-demand charge rather than in a commodity charge.[36]

A similar tariff approach has evolved within Canada for NEB-regulated pipelines. An SFV rate design is matched with a periodic review of rate levels and an incentive type of rate design that allows pipeline companies to share expense and capital cost savings with shippers between periodic rate reviews.

Another change is that ANGTA provided full cost-of-service rate recovery for all costs. This would have included the actual costs of construction if those costs exceeded the estimated costs filed with the certificate application. Today's pipeline rate regulation has moved toward putting the pipeline owners at risk for cost overruns or increases. Initial operating rates are established based upon estimated costs to complete a project. Pipeline owners today have a tremendous incentive to control project costs because initial rates usually are based upon

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[36] FERC has expressed a willingness to consider alternative forms of rate design, and this has occurred when a pipeline and its customers can structure a rate design with sufficient support to be filed as a settlement offer with FERC.

estimated costs to completion. Should actual costs exceed these costs, they have the opportunity to try to recover them in a rate proceeding (and indeed, the burden of proof to demonstrate prudence of costs falls on parties making those arguments). However, rate proceedings are costly and inherently uncertain as to outcome. Hence, they are not the recourse pipeline owners are prone to seek. Pipeline owners have a real incentive to contain construction costs to certificated levels.

A major tariff issue in today's regulatory environment is the issue of rolled-in vs. incremental rates for service. This is particularly of concern for major new pipeline investments that integrate with downstream existing pipelines. New facilities under ANGTA were, of necessity, incrementally priced. There were no existing facilities to roll the costs into. Although the Canadian ANTGS prebuild in 1983 was incrementally tolled, incremental vs. rolled-in tolling has continued to be an issue for every major expansion of the prebuild portions of the ANGTS system since that time. The NEB has continued to support a rolled-in standard for Canadian mainline pipelines, primarily on TransCanada.

A pipeline from the North Slope to Alberta would constitute a new transportation route, so service on the pipeline would be incrementally priced. However, capacity on pipelines and routes out of Alberta would necessarily be expanded and therefore be subject to the incremental vs. rolled-in pricing controversy.

Other major issues in the current integrated North America gas market are common tariffs and electronic access to information. Today's market is an open market. Gas is a true commodity and is interchanged both financially and physically through a variety of contract forms and terms. These terms necessitate common or like language in tariffs defining everything from gas quality to nomination standards and uniform multisystem transportation agreements. None of these issues were contemplated within ANGTA. A variety of modern issues ranging from gas quality to contract terminology were not contemplated or built into ANGTA.

The Alliance Pipeline Project from Northern British Columbia to Chicago is an example of a new major pipeline project where all these issues had to be anticipated and built into the project design, and ultimately into the project approvals and financing. This is a bullet high-pressure system that takes gas from the start of the project in the north and moves it

SECTION 7

Potential Returns from Pipeline Investment

As described in Section 6, the state could choose to pursue either or both of two ownership options associated with the Alaska Gas Pipeline. These two options are ownership in the pipeline and ownership of capacity rights purchased from the pipeline owner through the open-season process. This section evaluates risks and reviews potential returns associated with each of these two options. Additionally, potential effects on the state's cash flow are discussed.

Pipeline Ownership

State ownership in the pipeline could conceivably range from partial to full ownership. Given the planning and development investment that private sponsors have already made in the pipeline, the substantial further investment still required, and the fact that the state does not have adequate expertise to lead pipeline development, we do not believe full ownership is a practical option. Accordingly, state ownership would very likely be limited to partial ownership. The state's partial ownership share is usually discussed as being the same ratio as the state's royalty rights to gas produced on the North Slope, or 12.5 percent. However, the state could take ownership at levels above or below this share.

Ownership Risks

As discussed in Section 6, project ownership would allow the state, as part of the ownership structure, to participate in selling pipeline capacity. But in order to use capacity for its own gas, the state would need to purchase capacity rights under the same open-season rules as any other customer—ownership does not bestow any capacity rights or privileges.

The Alaska Gas Pipeline would be regulated by FERC in the United States and the NEB in Canada. Construction of the project would not begin until long-term contracts are in place to reserve all or most of the system capacity. Tariffs and the return on the investment in the

pipeline would be established based on negotiations between pipeline owners and customers that buy capacity rights on the system. Returns on equity investment in the system would be in the range of 12 percent to 13 percent if negotiations and regulatory approval were to follow those that occurred with the Alliance Pipeline Project. There might be incentives that could increase returns above this level.

Although the investment would earn a regulated return, there would be risks of earning a lower return than that established in the negotiation and regulatory approval process. These risks include risk of construction cost overruns, project abandonment or mothballing, inadequate capacity subscription or customer default, operating problems, regulatory setbacks, insurance inadequacies and easement conflicts. Each of these risks is discussed below.

Construction Cost Overruns

As described in Section 6, construction of the Alaska Gas Pipeline alone could cost upward of $10 billion in 2001 dollars—a gas conditioning plant on the North Slope and expanded pipeline capacity out of Alberta would be billions more. Although contingencies are included in the sponsor's cost estimates, actual costs could well grow above those estimates. There are a number of developments that could cause cost overruns. These include the following:

- Problems with new technology or approaches associated with the project
- Construction productivity problems in the arctic conditions
- Inadequate skilled labor and other resources to construct the project efficiently
- Construction delays. These could occur from more adverse weather conditions than planned, interruption in delivery of pipeline or other materials, labor disputes, accidents and safety problems, technology difficulties, unplanned environmental occurrences (including archeological finds) and political developments
- Demand for pipe to meet project needs pushing pipe prices above budgeted levels
- Enhanced security in response to terrorist threats
- Mismanagement, particularly of developments that could cause cost overruns

Typically in a regulated environment, however, construction cost overruns are largely recoverable as long as they can be defended as being prudent. For example, cost increases due to project delays because of abnormal weather would be viewed as unavoidable and therefore likely would be added to the owner's rate base. Although other parties, such as pipeline customers or FERC or NEB staff, might resist such adjustments, they would typically have to prove imprudence in order to exclude cost overruns from a revised tariff. If the owner were not able to find ways to contain unavoidable costs through cost reductions elsewhere, FERC or NEB might award it a lower than anticipated rate of return, but this would not likely be a substantial adjustment. So, the pipeline owner's risks from cost overruns are practically limited to imprudent costs, regulatory delays before rate relief is granted for unavoidable cost increases, and a potential for FERC and NEB to allow a lower than planned rate of return due to lower than expected performance in cost management.

Project Abandonment or Mothballing

Although contracts signed for pipeline capacity should reduce much of the risk that the Alaska gas pipeline would be abandoned or mothballed (indefinitely delayed), such a risk does exist. It is not unusual for a major energy project to be delayed or abandoned. In fact, ANGTS has already been delayed once. Many investments made in its planning process during the late 1970s and early 1980s are likely to be lost. There have been numerous other smaller energy projects in Alaska that have not been constructed. On a larger scale, during the 1980s, numerous nuclear power projects in the United States were abandoned or mothballed before construction was completed.

Unless the pipeline is not completed at the request of pipeline capacity owners, funds invested in an abandoned project could not be recovered and would be lost to project investors. Similarly, mothballing could result in lost investment or substantially reduced returns on investment made prior to mothballing.

Inadequate Capacity Subscription or Customer Default

The pipeline is planned to be full in a few years time and operate at a 95 percent capacity factor. There is some risk that the pipeline would not carry this load level or be subscribed under ship-or-pay contracts through its entire project life. Also, it is possible for a party that

has contracted for pipeline capacity to default on payments. Further, if gas prices are down at the time a contract for pipeline capacity expires, it is possible that the capacity would not be resubscribed and could remain idle for some time. As a result, some costs could go unrecovered.

Operating Outages

The pipeline owner would be responsible for providing usable pipeline capacity with limited outages for maintenance and limited system failures. Outages due to "force majeure" (acts of God) would likely require customers to continue to pay for their capacity reservation despite the temporary interruption. Nonetheless, to the extent that the pipeline operation outages exceed the negotiated terms for allowable outages, revenues could be lost and returns negatively affected. System outages can occur from a variety of causes. These include equipment failure or lower than expected performance; management, information or process failure; labor or contract disputes; and catastrophic events. Extended outages could significantly lower revenues and returns for the pipeline owner.

Regulatory Setbacks

The pipeline would be operated under the regulatory oversight and approval of FERC, NEB and numerous other national, state, provincial and local regulators. Through the associated regulatory process, decisions could be made that negatively affect the owner's ability to earn its authorized return. Risks of lower returns could result from decisions made within the existing regulatory framework, changes in regulatory requirements, and tariff and procedural interventions by third parties.

Insurance Inadequacies

Because the Alaska Gas Pipeline would be so capital intensive, it is vital that it carry customary levels of property and liability insurance. However, there is no assurance that this insurance would be available, at least at affordable rates in the future. Inadequate insurance coverage could result in significant losses for the pipeline owner.

Easement Conflicts

The pipeline would require that easement rights be acquired from thousands of landowners. In addition, it might have to acquire rights from First Nations groups in Canada. Even if easements and rights of way are obtained through standard legal processes, the risk would exist for legal conflicts and claims arising out of construction or operation of the pipeline.

Projected Returns from State Investment in Pipeline

Financing of the Alaska Gas Pipeline is assumed to include a debt/equity ratio of about 70/30. The two sponsor groups evaluating pipelines from the North Slope to Alberta are projecting this capital structure, and the Alliance pipeline had this structure. With the 70/30 debt/equity ratio for the Alaska Gas Pipeline, debt cost is assumed to be 8 percent and the regulated return on equity is assumed to be 12 percent.

However, actual returns on equity could vary from planned levels. There is risk of lower return due to the risks outlined above. There is also a prospect of a higher return if the pipeline owner performs in a way necessary to achieve incentives that would likely be built into the tariff.

Financial Model

To understand the range of possible returns from state ownership, a financial model was developed by the Department of Revenue's consultants. The primary focus of the model was to estimate the range of possible returns that could be earned from investment in the North Slope-to-Alberta pipeline given the various investment risks outlined above. The model also provides for analysis of variances in the tariff from different assumptions relating to taxes paid on returns to equity and debt components to invested capital.

However, the model was not developed to estimate the absolute tariff level. So, resulting tariff calculations should be considered as only general approximations. Further, no estimates were made of the cost to expand capacity out of Alberta to complete the transport of North Slope gas to final markets.

The model calculates annual revenue requirements and levelized tariffs necessary to meet those requirements over an assumed 25-year life of the pipeline. It then calculates the 25-year

internal rate of return (IRR) based on application of the tariff and a range of projected actual operating results. The model also includes a tax component that calculates potential income tax benefits from state ownership.

The model estimates both rate base and a replacement cost new less depreciation (RCNLD) value of the pipeline for each year of the projected 25-year operating period. The rate base estimate is used to calculate annual return requirements based on the debt/equity ratio, debt costs and regulated equity returns discussed above. The RCNLD estimate is used to calculate annual property tax associated with the pipeline.

The model calculates revenue requirements in each year as the sum of operation and maintenance costs (including administration), depreciation, property tax, income tax and return on rate base (in terms of interest expense and return on equity). Capital, operation and maintenance costs were directly input based on estimates made by the sponsors evaluating the Alaska Highway Route. Depreciation was calculated based on straight-line, 25-year depreciation rate. Property taxes were calculated by applying an assumed tax rate of 2 percent (20 mills) to the RCNLD value of the pipeline in each year. Income taxes are discussed separately below.

In the model, the annual revenue requirement calculations are in turn used to calculate a levelized tariff per MMBtu. This tariff, when applied to the projected gas volumes, produces a cash flow that yields the same IRR as the projected 25-year revenue requirement. The tariff is calculated both in terms of nominal prices (including projected inflation) and in terms of real prices (2001 dollars). In the base case, it is assumed that federal income tax would be paid on all returns to invested capital. That is, it is assumed that interest paid on bonds issued to finance the project would be taxable and that the state's share of net income to the project would also be taxable. However, the model provides analysis of the degree to which the pipeline tariff would be lower with tax exemptions to these returns (see Income Tax Approach and Assumptions, below).

The model projects actual operating results under a number of different possible scenarios. These scenarios reflect both risks of achieving lower than regulated target returns and possibilities of higher than target returns from capitalizing on incentives assumed to be included in the tariff. Probabilities are assigned to a range of risk and incentive possibilities,

and a set of Monte Carlo simulations of operating results are run. The results are compiled into an expected value and a risk profile (probabilistic range) of IRRs from ownership investment in the pipeline. The structure of the risk analysis is shown graphically in Appendix B.

Income Tax Approach and Assumptions

If pipeline ownership is in the form of a single corporation with specific shares held by the individual owners, income taxes would be assessed before returns flow back to the owners. This would mean that return on the state's equity share would be taxed in the same way as that of the private owners. However, if ownership in the pipeline is in the form of a partnership or limited liability company, the possibility exists that the return to the state would not be taxed.

Income tax was calculated assuming that 50 percent of the pipeline investment and income generated from the investment would be within the United States (Alaska) and 50 percent would be within Canada. For the U.S. portion of the pipeline, a 9.4 percent state and a 35 percent federal income tax rate were assumed. Federal tax was calculated assuming a 1.5 times accelerated depreciation schedule over 15 years, with benefits of this tax treatment flowing through to the tariff. For returns generated in Canada, provincial tax rates were estimated to average 14 percent and the federal income tax rate was assumed to be 22 percent, based on official projections by the Canadian government. Canadian tax law recognizes depreciation costs as capital cost allowance (CCA). A 4 percent annual CCA is allowed on the declining value of pipelines. The CCA is 20 percent on general equipment and 30 percent on transportation and computer equipment. The weighted average for investment in the Alaska Gas Pipeline was estimated to be 5 percent for input to the financial model.

Risk and Incentive Inputs

As outlined above, pipeline owners face risks and incentives that can affect returns on the owner's investment in the Alaska Gas Pipeline. Many of the risks were reflected in the financial model through the following inputs.

The risk of construction cost overruns was evaluated by assuming that there was a 40 percent chance of cost overruns. The size of overruns evaluated ranged from 15 to 30 percent. It is recognized that some of the cost overruns would be recoverable through a tariff adjustment; a range of 0 to 100 percent recovery was evaluated.

The chance of project abandonment or mothballing was assumed to be 3 percent.

Inadequate capacity subscription or customer default was addressed with three separate inputs. First, a 1 percent probability was input for the risk of a customer with reserved capacity being unable or unwilling to pay for his take-or-pay obligation because of contract disagreements or financial difficulty. The percent of pipeline capacity affected was evaluated at 5 to 30 percent. The number of years affected was evaluated at 1 to 6 years.

Second, the prospect of the pipeline not being fully subscribed by the time it begins operation was given a 5 percent chance. The percent of the pipeline capacity unsubscribed was assigned a 5 to 10 percent probability, and the number of years affected was evaluated at 1 to 5 years.

Third, insufficient demand for pipeline capacity when individual capacity reservation contracts expire was evaluated at a 5 percent probability. The expiration of contracts was evaluated at years 10 to 25, and the percent of capacity left unused as a result was evaluated at 10 to 25 percent.

Operating outages were evaluated for both chronic above-plan outage levels and for a one-time catastrophic event. Chronic outages were assumed to have a 10 percent chance, with uncompensated downtime running from 2.5 to 5 percent. The chance of a one-time catastrophic failure was evaluated at a 2 percent chance. The one-time event was given an equal chance of occurring in any of the 25 years in the analysis period.

It was assumed that the owner would have an incentive to share in the benefit of cost savings during construction. The owner realizing shared-savings was evaluated assuming there was at a 10 percent chance of a 10 percent cost underrun, and that the owner would share 25 percent of the savings.

Estimated Returns

Applying the above assumption, the model shows that the expected IRR value for ownership investment in the Alaska Gas Pipeline is 8.1 percent to total capitalization and 10.1 to equity. For equity, this is 1.9 percentage points lower than the assumed regulated rate of return. The range of returns to total capitalization is from 7.1 percent at the 10th percentile to 8.8 percent at the 90th percentile, while the range of returns to equity is from 5.8 percent at the 10th percentile to 12.0 at the 90th percentile.

These ranges are shown in risk profiles presented in Figures 7-1 and 7-2, respectively. The risk profile shown in these figures is a graph of the probability that returns would be at or lower than the levels listed on the X-axis of the chart. Not reflected in these profiles is the chance that the state could actually lose money through the pipeline investment. This would happen if the state invested capital only to have the pipeline not be completed. The chances of such an occurrence are unknown. However, as noted above, this possibility was assigned a probability of 3 percent for the purposes of this analysis.

Figure 7-1
Probabilistic Range of Returns to Total Capital Invested in the Alaska Gas Pipeline

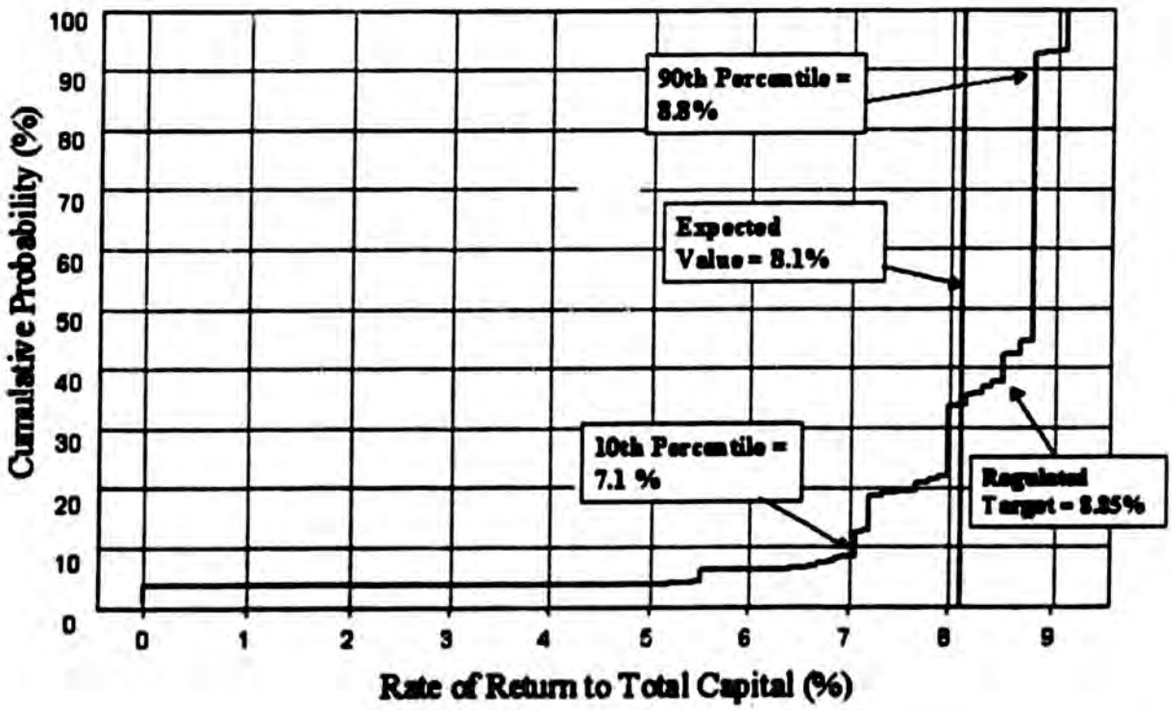
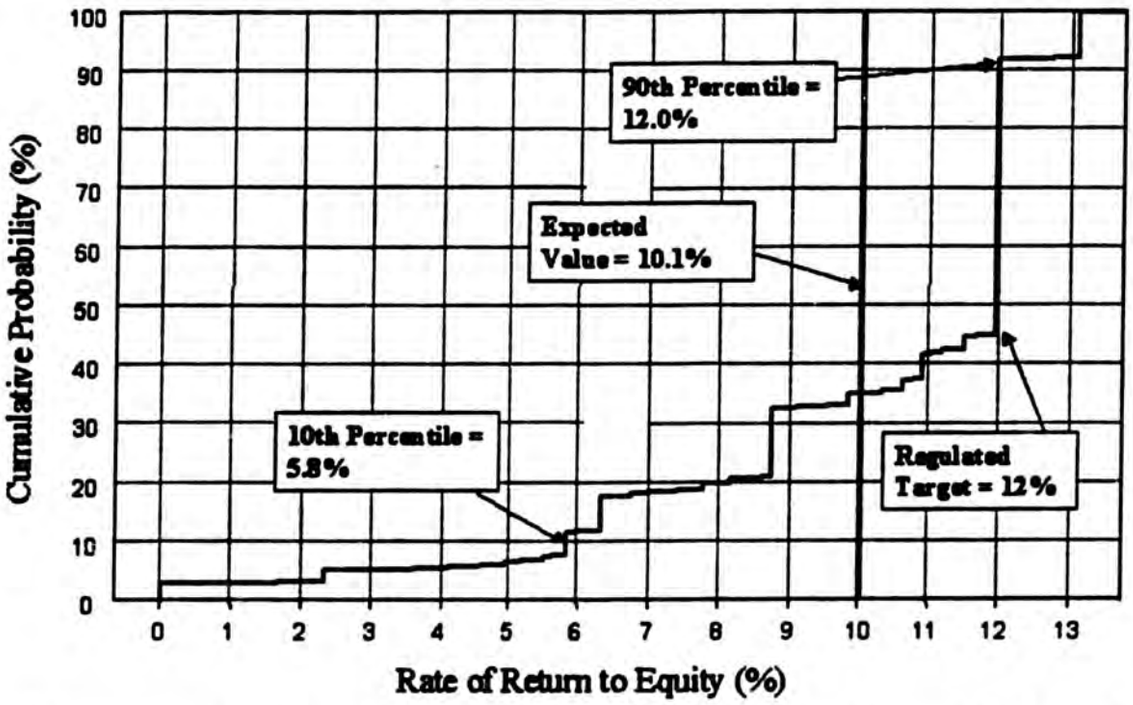


Figure 7-2
Probabilistic Range of Returns to Equity Invested in the Alaska Gas Pipeline



Possible returns on equity are presented for various levels of ownership participation and probabilities in Table 7-1. These estimates are based on a projected debt equity ratio of 70/30.

TABLE 7-1
Alaska Gas Pipeline
Probable Returns to Equity Investment

				Return to Equity					
				Percent Return			Avg. Annual Return (Millions of 2001$)		
Ownership Level	Capital Structure (Millions of 2001$) Debt	Equity	Total	Expected Value	10th Percentile	90th Percentile	Expected Value	10th Percentile	90th Percentile
12.5%	1,085	465	1,550	10.1%	5.8%	12.0%	52	36	59
25.0%	2,170	930	3,100	10.1%	5.8%	12.0%	103	71	119
50.0%	4,340	1,860	6,199	10.1%	5.8%	12.0%	206	143	237
100.0%	8,679	3,720	12,399	10.1%	5.8%	12.0%	413	285	474

Base inputs to the model were developed on the assumption that all returns to invested capital would be subject to federal corporate income tax. However, in separate computer runs, the financial model was also used to calculate tariff reductions that could be achieved if

project owners were 100 percent exempt from federal income tax. This included separate analyses for federal income tax on returns to equity (profit) and on interest associated with debt used to finance the pipeline. For that analysis, a 70/30 debt-equity ratio was assumed.

The analysis showed that tariffs would be about 8 percent lower if the project owner or owners were exempt from federal income taxes on 100 percent of the return to equity. If bonds issued to finance the debt portion also were tax exempt, it was assumed that the interest rate on the bonds would be 5.6 percent rather than the 7.5 percent in the base analysis for taxable debt. This analysis showed that tax-exempt bond financing would lower the pipeline tariff by an additional 10 percent. So, if the project were able to avoid federal income tax on its profits and was financed with tax-exempt debt, the pipeline tariff would be a combined 18 percent lower than under fully taxable ownership.

If the tax exemptions applied only to a 12.5 percent state ownership share of the pipeline, the overall effect on reducing the tariff would be just 2.2 percent.

Given the speculative nature of such cost savings and ownership arrangements, the method for allocating these cost saving (in a separate tariff for the state or as a reduction in the common tariff for all customers) was not considered in this report.

Sample printouts of model input and output are provided in Appendix C.

Ownership of Pipeline Capacity Rights

In lieu of an equity investment in the Alaska Gas Pipeline, or in conjunction with an investment in the project, some proponents have asked whether the state should acquire pipeline capacity rights. The state could acquire capacity rights by making a contractual commitment for firm capacity. This commitment would likely consist of a long term (15 or 25 years) binding obligation to ship or pay for the capacity. The ship-or-pay obligation would probably be in the form of a fixed-demand charge for the obligated capacity. Because almost all of the owner's costs would be fixed, almost all of the revenues generated from the tariff would be through the fixed-demand charge. There would also likely be a nominal commodity charge per thousand cubic feet (mcf) of transported gas to cover the owner's variable costs (costs that vary according to volumes transported through the pipeline).

Although the process for allocating pipeline capacity rights under ANGTA is uncertain, it is assumed they would ultimately be sold through an open-season process. Because pipeline owners need early commitments to demonstrate project need to regulators and to manage their own risks and obtain any necessary project financing, the open season, and hence the state's commitment to pay for its capacity share, would occur before final planning and permitting activities and pipeline construction.

Once the pipeline is constructed and operating, the state could use its capacity in either or both of two ways. First, the state could use its capacity to move its own gas taken as in-kind royalty. It could sell the gas in Alberta or pay for other pipelines to further transport the gas to market in the Lower 48 or Canada. Second, the state could resell pipeline capacity rights to others that have gas to transport. The price for this service could vary above or below the tariff the state pays for the capacity rights.

Risks of Capacity Ownership

Risks associated with state purchase of capacity rights on the Alaska Gas Pipeline are described below for each of the two potential uses of the capacity: transport of the state's gas if the state takes its royalty share on an in-kind basis, and resale of capacity rights for gas transportation by others.

Transport of State Gas

The state has the option to take its royalty share on either a value[37] or in-kind basis; the state can shift between these two bases on six months' notice. If the state takes its royalty share on an in-kind basis, it may do so with the intent of realizing higher value than it would by simply taking its royalty share on a value basis. Purchasing capacity rights on the pipeline would be a logical first step to achieve this objective.[38] As noted above, obtaining such

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[37] Based on state law (AS 38.05.180) and lease agreements, the royalty gas value is based on the value of pipeline-quality gas ready for transport from the North Slope under the terms of some of the leases.

[38] Taking the state's royalty share in kind without proportionate reserved capacity on the pipeline might create undue risks that the state could either not get its gas to market or be forced to do so at a relatively high cost and resulting relatively low return. This is because there will be substantial gas production and treatment capability on the North Slope that will likely keep the pipeline filled; those without pipeline capacity rights would be shut out or forced to pay high rates to gain access. This risk is eliminated, of course, if the royalty-in-kind purchaser has its own reserved capacity.

capacity rights would require a long-term commitment (15 years or more) to take or pay for the reserved pipeline capacity. Taking royalty in-kind does not require the state to nominate capacity if the buyer nominates its own capacity or uses the gas on the North Slope.

While the intent would be to earn higher returns, taking its royalty share in-kind—together with purchase of pipeline capacity rights—creates additional costs and risks for the state relative to taking its royalty share in-value. These costs and risks include the following:

1. Costs incurred to market the gas.
2. The risk of absorbing losses from high costs or poor market conditions.
3. The risk of paying for capacity even during extended outages caused by force majeure.
4. The risk of not realizing as high market prices as the gas producers and therefore earning less than if the state were to take its royalty share on a value basis.

Each of these costs and risks is discussed in more detail below.

The primary benefit of taking the state's royalty share on an in-kind basis with purchase of pipeline capacity rights is that it could ensure that the state's proceeds are based on the true market value of the gas. That is, it avoids the risk that the royalty share, when taken on a value basis, could be calculated at an artificially low value.[39] Losses to the state from royalties calculated on an artificially low market price can easily exceed the extra costs and risks associated with taking the state's royalty share on an in-kind basis.

The following subsections discuss each of these four extra costs and the risks associated with taking the state's royalty share on an in-kind basis with purchase of pipeline capacity rights.

Gas Marketing Costs

The state's costs to market the gas in a downstream market is an extra cost the state would bear with its royalty share taken in-kind. It would likely include the cost of establishing a

39 The general basis for the calculation of value when royalties are taken on a value basis will be the higher of value delivered to market or the proceeds received less transportation costs. Market value will likely be determined from sales prices at market hubs. This might be in Alberta (e.g., AECO) or closer to its actual end use, with prices at a number of hubs in the Lower 48 states and in Canada used to calculate market value. The transportation costs will, at a minimum, be the cost of delivering North Slope gas across the Alaska gas pipeline to Alberta. If market value is established closer to market, transportation in other pipelines will also be included in the calculation.

state agency or paying a third party to market the gas and include some administrative costs to oversee the operation.

Management of the marketing process from the wellhead to the burner-tip is a sophisticated process requiring quick decisions implementing a well-conceived marketing strategy. It requires, among other things, the use of short- and long-term positions, various derivative products, and strict adherence to marketing and trading policies. Although the state could contract for a marketing service or develop the expertise in-house, the learning curve is steep and seemingly trivial decisions can have substantial financial and legal consequences.

Risk of Absorbing Losses from High Costs or Poor Market Conditions

Owning pipeline capacity rights and taking royalty share in-kind creates a risk that the state could realize a negative net value for its gas—which could happen if the Alaska Gas Pipeline tariff were higher than the value of gas delivered to Alberta. This could occur due to high pipeline costs or poor gas market conditions. Higher-than-expected tariffs could result from pipeline cost overruns. As described above, such overruns would likely be rolled into the tariff as long as they were not shown to result from imprudent management decisions. Lower-than-expected gas prices could result from poor market conditions. If adequate pipeline capacity to ship gas out of Alberta does not develop, the resulting oversupply in Alberta and the limited access to downstream markets would drive prices for Alberta gas prices to abnormally low levels. Low prices could also occur if new gas supplies and/or low demand in North America at least temporarily drive prices to levels that are lower than the transportation costs to deliver gas to market.

This risk does not apply to the option of taking the state's royalty share on a value basis. If the same poor market conditions were to occur under this option, the netback value to the producers would be negative. However, the state would likely simply receive no royalties rather than a loss. It is our understanding that the state would not be liable for a negative royalty payment from the producers' losses. Rather, it is assumed that the royalty would be waived or set at zero.

Force Majeure Risk

As discussed above in the subsection on Pipeline Ownership Risks, owners of pipeline capacity rights may be required to continue to pay for their capacity reservation during

periods of pipeline service interruption caused by acts of God. These could include interruptions due to events that are beyond the control of the pipeline owner (e.g., natural disasters, fires, explosions, terrorist acts, other sabotage and other catastrophes). If the state purchases capacity rights on the pipeline to market royalty gas, it runs the risk of continuing to pay during force majeure events. Such risks are avoided when royalty is taken on a value basis. (In any case, state royalty revenues would be interrupted if North Slope gas deliveries were interrupted—regardless whether gas were taken on a value or an in-kind basis.)

Realized Market Price Risk

Because gas producers have substantial expertise in marketing their products, they are likely to receive maximum value for their sales of North Slope gas. If the state were to take its gas on an in-kind basis and market it in downstream markets, it would probably have to establish a gas marketing agency and staff it with industry experts. Nonetheless, because marketing of wholesale petroleum products is not a core business of the state, there is some risk that it would not realize as high of a value in its sales as would the producers. All other things being equal, this would result in lower royalty value accruing to the state than if it were to take its royalty share on a value basis. On the other hand, there is a potentially significant opposite risk, that the calculated royalty share, when taken on a value basis, could be artificially low, possibly lower than the value achieved by taking the state's royalty on an in-kind basis.

Resale of Pipeline Capacity Rights

The state could take the risk of marketing its reserved capacity on the pipeline to others that have a need to transport gas to market. This could include existing oil and gas producers, as well as entities that might discover and produce gas in the future. To the extent that the state could sell, or release, its capacity rights for a higher price than the fixed charge it would be obligated to pay, plus its administrative costs, it would profit. In the opposite direction, the state would lose money if it could not cover these costs in its resale of capacity rights.

It has been suggested that the state might purchase capacity on the pipeline specifically to make capacity available so that future new production would have access to markets through the pipeline. The logic is that this would increase production and, with it, state royalty and tax revenues. However, to the extent that the pipeline would be full with production from existing wells, the state would already be benefiting from full production to fill the pipeline.

Once pipeline capacity opened up after production declines from existing wells, it would become available for new production. Therefore, the state does not have much to gain from risks associated with purchasing pipeline capacity rights for resale if it is indifferent to whose gas fills up the pipeline. This is not necessarily the case, however. There will be little exploration for gas for decades if those that would explore cannot get the gas they find into the pipeline. A diversified group of gas producers is desirable to the state, as is exploration and development in new areas in the state.

Returns from Capacity Ownership

Purchase of capacity rights have higher risks and potential returns than investment in a share of the pipeline itself. Returns are much less certain than the regulated return from pipeline ownership. The North Slope gas producers recognize this higher risk in establishing a "hurdle rate" of return for their projected cost for treating and transporting their gas. In their feasibility studies, the producers will probably require a relatively high rate of return on all investments they make in treating and transporting gas through the Alaska gas pipeline. Most of this risk consists of the fixed commitment to pipeline capacity.

As noted above, returns from capacity purchases made to market state royalty gas need to be assessed in terms of the state's ability to realize higher value than that calculated under a royalty value formula. Any extra value obtained from use of the pipeline to market royalty gas must be sufficient to cover the cost to market the gas, the risks of absorbing losses during poor market conditions, improper management decisions and force majeure events, and the risk that the state cannot market gas as well as the producers.

The potential for added or reduced overall returns to the state from purchase of pipeline capacity rights cannot be estimated until:

1. The precise method is determined for calculating the value of the state's royalty share. It is entitled to the higher of market value or sales proceeds.
2. The cost to market gas taken on an in-kind basis is estimated.

3. The estimated Alaska Gas Pipeline tariff is known and assessed against the prospects for poor market conditions, particularly as they relate to North America market access from Alberta.

4. The state's ability to market gas supplies relative to the producers' ability is assessed. State officials acknowledge that the state should never expect to be as skilled in marketing gas as those in the business.

Once these uncertainties are clarified, the state would be better able to assess the potential return from investing in capacity rights and taking its royalty payment on an in-kind basis.

Purchase of pipeline capacity for resale would be a speculative venture. Returns from pipeline capacity purchase for resale would depend on the state's ability to resell the capacity at a higher price than its tariff cost, plus the cost of administering the resale program. As noted above, it is not likely that purchase of pipeline capacity to hold for others would increase gas production and thereby increase state royalties. Therefore, the direct return from a pipeline capacity purchase for resale would simply be a function of the state's ability to resell the capacity at a higher level than its costs.

Effect on State Cash Flow

If the state were to purchase an ownership share in the pipeline equal to its royalty share of 12.5 percent, and assuming a debt/equity ratio of 70/30 and a $12.5 billion total project cost, the state's equity investment would be $465 million (2001 dollars). Equity contributions at higher ownership levels are shown in Table 7-1.

As noted above, with the risk assumptions made for this analysis, the expected rate of return on equity invested in the pipeline is projected to be 10.1 percent, with a 10 to 90 percentile range of 5.8 to 12.0 percent.

Investment of this capital in the pipeline would require a delay in realized returns. The state's obligation to advance cash for its equity investment would begin as soon as its purchase of an ownership share was complete. These payments would begin at relatively low levels as planning and engineering are completed, then increase to higher levels during actual pipeline construction. The pipeline would not start generating revenues until operations begin. We

have assumed that the earliest pipeline operations could start is 2009. The state's return on the equity it invested during planning and construction would be capitalized and rolled into the overall project capital base as part of "allowance for funds used during construction" (AFUDC). AFUDC would become part of the investment upon which the state and other pipeline investors would earn their return. Accordingly, between 2002 and 2008, the Permanent Fund, Earnings Reserve Account or other state funding source would be drawn down by the state's investment in the pipeline. This would total an estimated $465 million (under the assumptions stated above), of which $338 million would be direct investment from a state funding source, and $127 million would be in the form of AFUDC.

If the Permanent Fund (including the Earnings Reserve Account) was the source of funds, the investment would reduce Permanent Fund dividends by an estimated cumulative total of perhaps $60 or so by 2010. This reduction would be repaid in future years through earnings on the AFUDC component of the state's investment.

Ownership of capacity rights on the pipeline would have little effect on state cash flow under normal operating conditions. This is because costs incurred from monthly take-or-pay payments would be directly offset from sales revenues. Assuming that the capacity rights were being used to transport Alaska royalty gas to market for sale, revenues produced from gas sales would cover the cost of capacity rights. The risks to this normal cash flow are discussed above. Under the worst of the risk scenarios a force majeure event could occur, interrupting pipeline operations while the state is required to continue making its capacity payments. Under those circumstances, 12.5 percent ownership of the pipeline would reduce the state's overall cash flow by an estimated $21 million per month.

SECTION 8

Effect on State of Alaska from Pipeline Investment

This section evaluates the effects that financial participation in the Alaska Gas Pipeline would have on the state's financial integrity, creditworthiness and ability to pay for essential public services. Any damage to the state's financial integrity and creditworthiness would lessen its ability to finance projects for public services. This section also evaluates several non-financial issues, such as state involvement in pipeline management.

Effect on the State's Financial Integrity and Creditworthiness

A factor the state should consider in determining the manner in which it may participate in the project is the effect its participation would have on its financial integrity and creditworthiness. The state's overall financial integrity and creditworthiness is best measured by the credit rating assigned to its general obligation debt by agencies that rate debt as part of the lending process for public bond offerings. Three prominent rating agencies are Moody's, Standard & Poor's and Fitch.

Having a solid credit rating is a valuable benefit to the state, especially in times of fiscal uncertainty. Further, the state's credit rating indirectly inures to the benefit of or detracts from the rates that Alaska municipalities have to pay on their own debt.

The state itself has no outstanding general obligation debt, so the credit rating agencies have not re-evaluated Alaska's full rating recently. However, Alaska's most recent general obligation bond sale was rated at the high end of the ratings scale.

If the state were to participate financially in the gasline project, the rating agencies—in setting new rates for State of Alaska debt—would take into account several factors, including: (1) the form of the state's participation; (2) the feasibility and economic viability of the project and the likelihood of its completion; (3) the estimated increase in state

revenues generated by the project; (4) the effect of the project on the state's overall economy; and (5) the timing of the benefits and costs to the state.

As discussed in Section 4, a small amount of equity or debt currently could be made available to the gasline project without damage to the state's current credit ratings. However, a multibillion-dollar capital investment funded by state debt that would be sufficient to gain majority control or a major influence in the project would likely have an uncertain, if not immediately negative, effect on the state's credit ratings. This would be the case for several reasons, including the fact that the project is not a typical governmental investment (in public infrastructure, *e.g.*, highways, prisons, etc.).

In addition, the debt would represent a governmental investment of unprecedented concentration in resource extraction, an industry with a history of substantial price volatility. Unless major adjustments were made in the state's operations and anticipated capital expenditures, it is probable that such investment would have to be funded by a very substantial amount of new general obligation debt, revenue bonds or creative use of sources of equity. The result would be increasing the state's indebtedness with respect to standard yardsticks such as population, resources and economic indicators.

Finally, the returns to the state would be over the long term. And, particularly in the near term when the project is just starting operations, these returns would not be assured.

Importance of the State's Credit Rating

The state has good reason to maintain a solid credit rating. A downgrade of the state's rating would have direct and indirect financial consequences and, although harder to quantify, would create political problems between the state and its municipalities.

A reduction in the state's credit rating would result directly in higher borrowing costs each time the state entered the credit markets. This is true both for certificates of participation and general obligation debt. Higher debt costs would reduce the amount of money the state could borrow for public service projects. That is, the more money that is paid out in higher interest rates, the less money the state could borrow for the actual projects. This potential effect is discussed below.

The various state corporate entities (Alaska Housing Finance Corporation, AIDEA, Alaska Municipal Bond Bank Authority, Alaska Student Loan Corporation) that enter the debt market would also likely face higher borrowing costs. For those entities that contract with banks for additional credit support, the costs of bank lines and letters of credit would be more expensive. Furthermore, the state's strong credit position, as well as its substantial cash reserves, indirectly enhance the credit of municipalities throughout the state.

The higher borrowing costs would be evident not only in higher interest rates but also higher costs of bond insurance, further reducing the state's ability to raise as much money as it may want for public service projects.

And although of lesser direct effect to the state, the holders of state debt would see the value of their investments in the state diminish in value because a lower debt rating would reduce the value of state debt in the hands of existing bondholders.

The cost of a full step downgrade of the state's credit from the strong AA level to a strong single A level—while difficult to estimate—would be significant. A downgrade of the state's rating would ripple through all of the governmental units of the state, likely resulting in across-the-board downgrades. Ultimately, this would affect all of the state's $6.5 billion in outstanding bond debt, particularly as bonds matured and new bonds were issued.

Over the past 10 years the difference or spread between AA and A rates have averaged 16 basis points. While this is a good starting point to determine how much the cost of capital would rise after a downgrade, there is a larger story to tell. Until the early '90s, the state historically paid an "Alaskan penalty" on its bonds that ranged from 15 to 50 basis points. The market assessed this excess cost because of the distance of the state from the financial markets, lack of information and the isolation of the state's economy. The current high ratings of the state are the result of consistent performance of the state and its economy, and the prevalent perception that Alaska has significant resources available. A downgrade, however, would be a major event that could very well bring back the penalty for Alaska issuers.

Finally, Alaska is a "non-specialty state," meaning there is a small population and no tax benefit to in-state investors of tax-exempt bonds because there is no state personal income

tax. Therefore, the state relies very heavily on investors outside the state to purchase bonds, and a downgrade could hurt Alaska more heavily than it would a state with a larger population and state income tax.

In sum, the cumulative effect of these considerations if the state were downgraded from AA to A would likely be in the 25 to 40 basis points range. This increased cost of capital would result in an additional $250,000 to $400,000 in interest expense per year for every additional $100 million borrowed. Assuming a rolling level of debt at $6.5 billion, a downgrade could eventually cost between $16.25 million and $26 million annually.

Balancing State Benefits and Costs

The financial analysis above leads the Department of Revenue to conclude that a monetary equity investment in the Alaska Gas Pipeline would likely provide the state with a positive return on investment over the long term. The sources of state funds are limited, however, and likely would need to be raised through the issuance of some form of debt—which would present its own set of financial problems as discussed in detail above.

However, just because the state *can* invest on some modest level does not mean that the state *should* invest. In addition to the strictly financial issues, there are numerous practical aspects to the investment discussed below.

- Of some importance to the state in contemplating an equity or debt investment is the substantial risk it would entail if the state invests in the project as a business partner. Unlike a major oil company or integrated natural gas pipeline, the state has little capability to monitor or control those risks and does not have the financial strength to absorb large capital or operating losses. It would be different, however, if the state were simply a shareholder in a corporation that owned the Alaska Gas Pipeline. As a shareholder, the state would be shielded from any liability. The only risk would then be the stock price.

- If Alaska were to become an active participant in the enterprise as an equity investor, it would be required to advance funds almost immediately to buy into a sponsor partnership to gain the same rights as other equity investors. Thereafter, the state

would be required to meet continuing capital calls. Therefore, Alaska would need to have readily available funds for this purpose or make borrowing arrangements to make money available now and continuing for the next several years of construction. Both of these options would substantially infringe upon the state's flexibility to meet public service needs. Given the magnitude of the state's anticipated needs for public services, the policy and constitutional limits on the state's available funds, and the ongoing revenue shrinkage due to declining North Slope oil production, there would appear to be little room for such a financial commitment.

- Superficially, one might conclude that any equity ownership would give the state a degree of control over management of the Alaska Gas Pipeline system, including a control over major policy decisions—such as retention of gas or gas liquids for in-state use—which could not be obtained in other ways. However, it is highly unlikely that the existing ANGTS sponsors or producers group would be willing to make a significant amount of equity available to the state. We understand that various parties in one consortia already are seeking higher ownership percentages; other third parties are interested in joining the consortia; and many companies do not want the state as a business partner. Accordingly, there is a "sellers market." In this circumstance the sponsors would be dictating the terms of the state's investment, and the state would likely have very little negotiating leverage. Thus, as a partner, the state probably would become just a minority participant with limited, if any, management rights. The amount of information shared with the state probably also would be restricted. The state's interests are likely to differ in important respects from the sponsors, so that it frequently would be outvoted in the event of a dispute.

- As a participant in the Alaska Gas Pipeline, Alaska might magnify the conflict between its interest as a regulator of the project in its sovereign capacity and its already existing economic interest in the project as both a royalty holder and a taxing authority. There also would be a conflict between the state's duties to its citizens as a regulatory and taxing agency and the fiduciary obligations of the state as an equity partner to the other project partners. It has been suggested that the use of a separate state-established corporation or authority as an investment vehicle would mitigate this

conflict. While the interposition of a separate governing board certainly would help to mitigate the conflict, ultimate authority and control over the participation of the state in the enterprise would remain with the legislature and the governor.

- There is precedent in times of national emergency and wartime conditions for governments to become involved in the development, construction and ownership of pipelines.[40] Absent such extraordinary circumstances, public sector investment in pipeline projects is not customary in the United States. The Department of Revenue and its consultants were unable to find a single material natural gas pipeline project in North America today where a state or federal government entity was a participant. There still remain a few examples associated with Canadian provinces, however the trend is for privatization of those investments. There is precedent internationally for such governmental investments, but usually those circumstances are dictated by tradition, national security issues, World Bank financing requirements, or the inability to get the project developed any other way. None of those situations are applicable to this project.

[40] The classic example is the federal government's involvement in the construction of the "Big Inch" oil pipeline from the Gulf Coast to the East Coast in World War II.

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SECTION 9

Effect of State Participation on Project Success

This section discusses examines whether state participation as an equity or debt holder might help or hinder completion and operation of the project. This obviously is an important consideration for the state. Anything done to improve or hinder gas royalty income would have a measurable effect on the state's cash flow.

Interest of the Pipeline Sponsors

Among the issues discussed with the companies interviewed was how they viewed having the state as a partner and whether they saw the state as adding value to the project design, development, construction and operation process. As mentioned previously, for a variety of reasons the companies were not in favor of the state as a partner. At best, several of them thought the state would not materially aid implementation or operation of the project and, at worst, some thought the state's involvement would be a negative factor .

Those that believe the state's participation would impede progress of the pipeline said they were concerned about the state politicizing and slowing the multitude of decisions that must be expeditiously made—especially in route selection, marketing, procurement and selection of contractors. Although not critical of the quality of the state's personnel, the companies were concerned that the state simply lacked expertise in commercial enterprise activities and was not accustomed to making business decisions at the pace required by the project. Further, they were concerned that the state's presence in the project would needlessly interfere with or add layers of confusion to the complex financing program that would be required by some of the project sponsors. The requirements of the state and the requirements of the lenders vis-à-vis the state in the financing process might be incompatible and mutually burdensome.

Critical Success Factors

Industry's concern is borne out by an examination of the important factors that would be critical to the success of the initial phase of the project. These include the requirements for:

- Shipper contracts
- Pipeline design
- Federal, state and provincial approvals
- Construction permits
- Right-of-way and land use permits
- Off-take agreements
- Engineering, procurement and construction contracts
- Financing

The state would have little effect on the successful outcome of these requirements, except in expediting state right-of-way approvals, obtaining state and local permits and, if it so chose, to contract for the shipment of its royalty gas. The execution of most of these critical success issues are solely within the province of the Alaska Gas Pipeline. Most of the potential sponsors have had substantial experience with addressing these issues in the development and construction of natural gas pipelines throughout the world.

The state would not have any effect on the two most critical factors to the success of the project over the long term: the market for the natural gas and construction costs. The size of the natural gas market in Alaska is very limited. The marketplace will be the Lower 48, an intricate energy market with which Alaska has no commercial experience. Further, there is little the state could do to assist in the gas pipeline engineering and construction decision and implementation process. This simply is not a core competency of the state.

Supplying $300 million to $500 million of state funding really would not significantly assist the potential project sponsors, given their sizes and capabilities. In fact, the size of probable state funding likely would not be much different that the size of the project contingency factors built into the potential sponsors' economic modeling. So, from a financial point of view, the state's participation would be immaterial.

As discussed in Section 6, the North American natural gas landscape has been significantly changed over the 25 years a North Slope natural gas pipeline has been under consideration. Although the pipeline companies involved in the late 1970s and early 1980s were large, they still needed to seek outside capital sources, such as the state, to help fund the project. Today, with the wave of mergers and consolidations sweeping the oil and gas producer and pipeline industries, the major players interested in developing the gasline are much larger and much more sophisticated. Of the 10 companies interviewed for this report, the smallest, Alberta Energy, had an enterprise value of $8.4 billion; the largest, ExxonMobil, about $266 billion. (And the mergers continue: Alberta Energy on January 25, 2002, confirmed reports it will merge with rival PanCanadian Energy Corporation to create what could be Canada's largest oil and natural gas company with a market capitalization of approximately $19 billion.)

Several of the companies interviewed are so large—as shown in Table 9-1—that they said they did not intend to borrow to finance their share of the $10 billion to $18 billion project cost, but merely intended to "write a check" off their balance sheet.

TABLE 9-1

Enterprise Value of Oil and Gas and Pipeline Companies

Company	Enterprise Value ($MM)
ExxonMobil	265,706
BP	184,556
Duke	44,964
El Paso	40,808
Williams	23,523
TransCanada	22,505
Phillips	20,937
Anadarko	18,116
WestCoast	10,463
Alberta Energy	8,433

Enterprise Value = Market Value + Debt + Preferred Stock Value + Minority Interest - Net Working Capital

The size and sophistication of the industry and the size and complexity of the project give rise to several important realities Alaskans should consider in making the judgment whether to make an equity or other financial investment in a North Slope pipeline project.

If the state could provide a means for tax-exempt debt financing of the project, it might improve the economic feasibility of the project and therefore increase the chances the project is actually constructed.

SECTION 10

Conclusions

Based on information developed in this report, the Department of Revenue's consultants offer the following conclusions about state financial participation in the Alaska Gas Pipeline:

1) Even if state ownership were restricted to just pipeline facilities, full ownership of the Alaska Highway Route pipeline would require $9 billion to $10 billion (2001 dollars) for construction. Deferred returns to capital invested during the estimated seven years before the project is likely to be completed would bring the total estimated pipeline investment to $13 billion to $14 billion. (These deferred returns are referred to as Allowance for Funds Used During Construction, discussed in Section 7 of this report.)

2) Without legislative action, the state does not have a ready source of cash for such a large investment. This is true even if the state were to limit its investment to 12.5 percent, an ownership equal to its royalty share of North Slope natural gas. Even at that reduced ownership level, the state's share of the total project investment could be as much as $1.75 billion (12.5 percent of $13 billion to $14 billion).

3) The state could make a significant investment if the legislature changed state law to direct the Permanent Fund to write a check. A 12.5 percent investment in the pipeline, assuming it was all equity and no debt, would take about 7 percent of the Permanent Fund. Even if the investment were 30 percent equity and 70 percent debt, the equity investment would still take more than 2 percent of the Permanent Fund's market value — making it the single largest holding of the fund. This large of an investment in a single entity, with the risks discussed in this report, might well violate the Prudent Expert Rule in state law governing Permanent Fund investment decisions. Additionally, about 80 percent of the state's unrestricted general purpose revenue currently is derived from oil and gas taxes and royalties. Permanent Fund investment in the pipeline would exacerbate the state's heavy reliance on one industry.

CORRECTION

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Department of Education & Early Development
State of Alaska

SECTION 10

Conclusions

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4) The legislature could appropriate money from the Earnings Reserve Account of the Permanent Fund to a state agency or other corporation to make the actual pipeline investment, thereby avoiding the issue of what is a permissible Permanent Fund investment. However, the Earnings Reserve Account is the Permanent Fund's sole method of absorbing market volatility, and any significant withdrawal from the account would jeopardize Permanent Fund dividends and inflation proofing.

5) The Alaska Constitution does not allow general obligation bonds to finance state participation in a joint business venture. This would limit the state to financing and owning 100 percent of the project. Further, such a major issuance of general obligation bonds or other state-supported debt would compromise the state's creditworthiness and, as a result, reduce its credit rating. At the state's current level of indebtedness, a downgrade from an AA to an A rating could increase the state's overall borrowing costs by an estimated $16 million or more per year. The state's ability to finance other public services also would be compromised. In addition, a reduction in the state's creditworthiness would likely have a negative, cascading effect on municipalities and other public agencies in Alaska.

6) The most plausible source of state participation through debt funding would be the issuance of taxable revenue bonds, secured for example by ship-or-pay contracts with the North Slope gas producers. However, the feasible size of such an issuance is uncertain. State issuance of bonds large enough to finance 70 percent of a 12.5 percent share of the pipeline (approximately $1.2 billion) would place the state in uncharted waters. Although ship-or-pay contracts with the producers should provide good security for the bonds, the large size of the debt relative to any previous State of Alaska revenue bond issuance, the manner and nature of the use of the bond proceeds, financial market pricing and repayment security requirements raise novel issues in the context of an Alaska gasline.

7) It theoretically would be possible for the state to sponsor a private corporation of Alaska investors to participate in the project. However, there are myriad practical, legal and public policy issues that need further review, including the source of investment funds, the qualifications for investors, tax implications, management of the entity,

constitutional matters and administration of the program. More importantly, it is difficult to understand how this proposal would provide any material improvement over any other available source of gasline investment capital. It appears to introduce yet another layer of complexity to an already difficult situation.

8) The largest risk associated with investment in the pipeline is that it would not be completed. In that case, the state's investment would be lost. Assuming the project would be completed, return on the state's investment would be regulated by the Federal Energy Regulatory Commission in the United States and the National Energy Board in Canada, and would likely result in a return consistent with or higher than state investment guidelines. Assuming a FERC/NEB-approved target return to equity of 12 percent, the state could expect to earn an average return to equity of about 10 percent. Probability analysis shows that average returns to equity over the life of the pipeline could range from 5.8 percent at the 10th percentile to 12 percent at the 90th percentile. Returns on the debt portion of the state's investment, however, would be limited only to the associated interest rate on that debt.

9) Pipeline ownership does not automatically provide the owner with capacity to ship gas on the pipeline. Capacity to transport gas would need to be separately purchased though an open-season process.

10) The state's need to purchase pipeline capacity rights to transport gas is dependent upon whether the state decides to take its 12.5 percent royalty share of North Slope gas on an in-value or in-kind basis. Pipeline capacity purchase might be prudent if the state decides to take its royalty share on an in-kind basis, in that it would assure the state of capacity to transport its gas to market. Otherwise, purchase of pipeline capacity would be speculative. Since the pipeline is likely to be full from its outset, purchase of capacity to provide a pathway for future discoveries would not increase total North Slope gas production or royalties paid to the state.

11) The primary benefits of establishing a state-owned public corporation or authority to construct and operate the pipeline are in the legal ability to assist state ownership and financing of the project. Such establishment could also reduce the conflicts of interest that might otherwise exist from direct state ownership. Separating the ownership into a

semi-autonomous function could at least attempt to build a barrier between the state's responsibility to regulate the pipeline and its interest in maximizing return to its investment. However, it is unlikely that a state-owned corporation or authority would reduce pipeline costs. Without a specific exemption from the private-activity restrictions in federal tax laws, neither the state nor a state-owned corporation or authority would be able to issue tax-exempt debt to finance the pipeline.

12) It is unlikely that the state could provide any loan guarantees to other investors in the pipeline. The Alaska Constitution prohibits the state from "lending its credit directly to benefit a private entity." Regardless of the state's ability to do so, it appears there is little to no interest among prospective private pipeline sponsors for the state's participation in the project's financing, unless it could be tax-exempt. Therefore it appears that providing state loan guarantees or taxable debt would not aid project feasibility.

13) State ownership would not likely improve the feasibility of the project or be valued by private-sector project sponsors. There was a general consensus among industry representatives interviewed that a public/private ownership relationship with the state either would not help or would be a hindrance to the project. Reasons given include the following: State politics could impede and otherwise compromise the decision-making process; pipeline ownership and operation is not within the core mission or competencies of the state; state decisions would be complicated by its dual role as owner and regulator (even if mitigated by a state-owned, semi-autonomous entity); and general differences between public and private goals and cultures would detract from the decision-making process. These factors would create additional risk for pipeline investors and cause them to not favor the state as a partner in the project.

14) If the private sponsor groups welcomed the state as a partner, the state would receive some form of management participation based upon the level of its financial contribution. The state, however, would have a fiduciary responsibility to its partners to keep non-public data in confidence. The state may find itself, therefore, in an untenable legal and ethical position trying to balance the informational needs of the state government with its partnership responsibilities. In truth, since the gasline project will

be subject to extensive regulation by various U.S. and Canadian governmental entities, much of the information pertinent to the partnership will be available through the regulatory process.

SECTION 11

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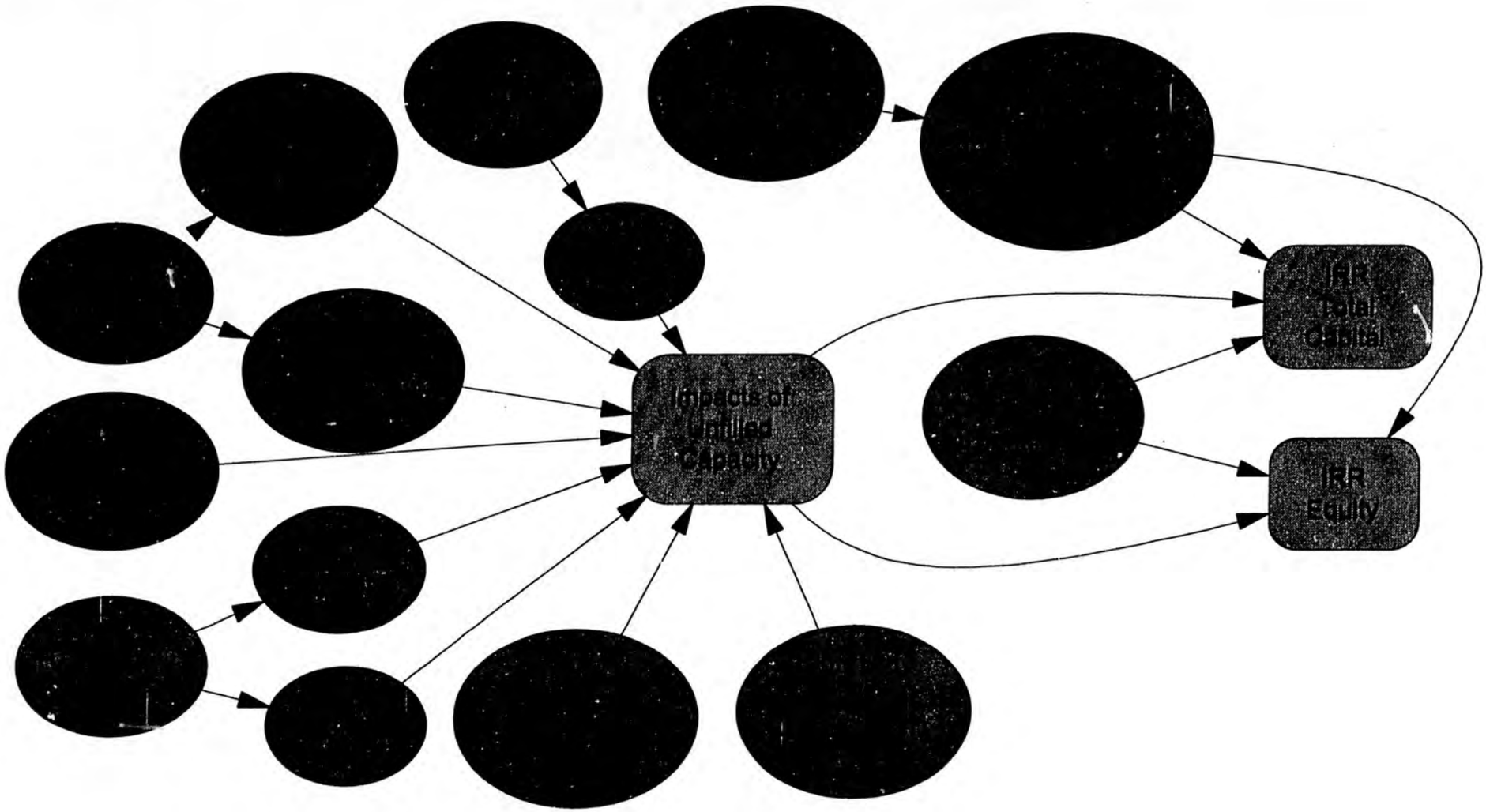
We would also like to recognize our consultants and thank them for their contributions. CH2M HILL's Dave Gray, Tom Kinnert and Steve Reynolds prepared the analysis of the pipeline investment setting, regulatory constraints, risks and returns, and projected effect on the state's cash flow. They also created a financial model to simulate the state's investment and risk profiles. Bill Garner of Petrie Parkman & Company prepared the analysis of financing and ownership options, feasibility and the potential effects of state participation on the state's creditworthiness and potential project success.

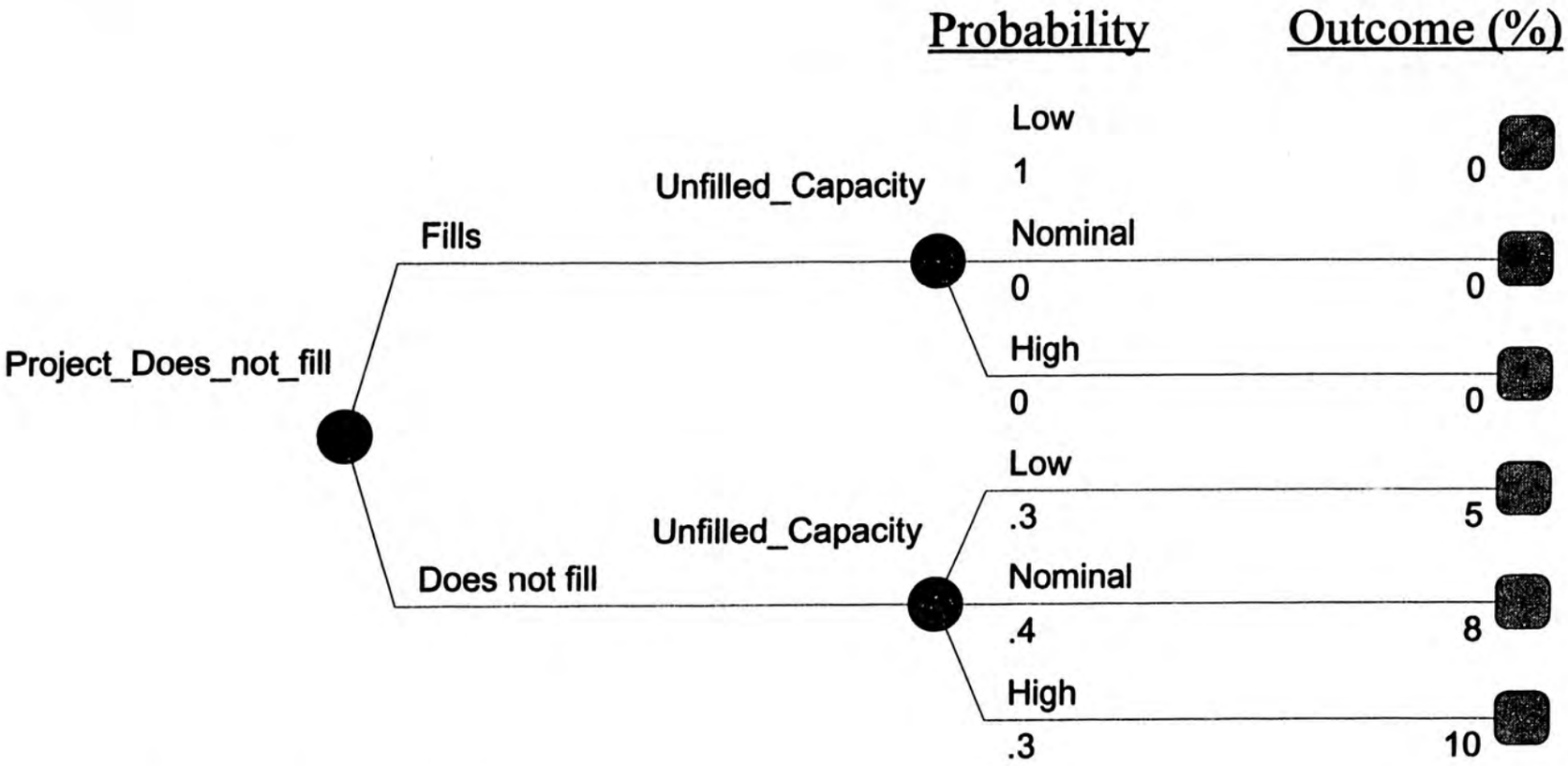
Appendix B
Risk Analysis Structure

Cost Drivers and Uncertainties Effecting Returns on the Alaska Gas Pipeline

Influence Diagrams illustrate conditional relationships between decisions, uncertainties, & outcomes

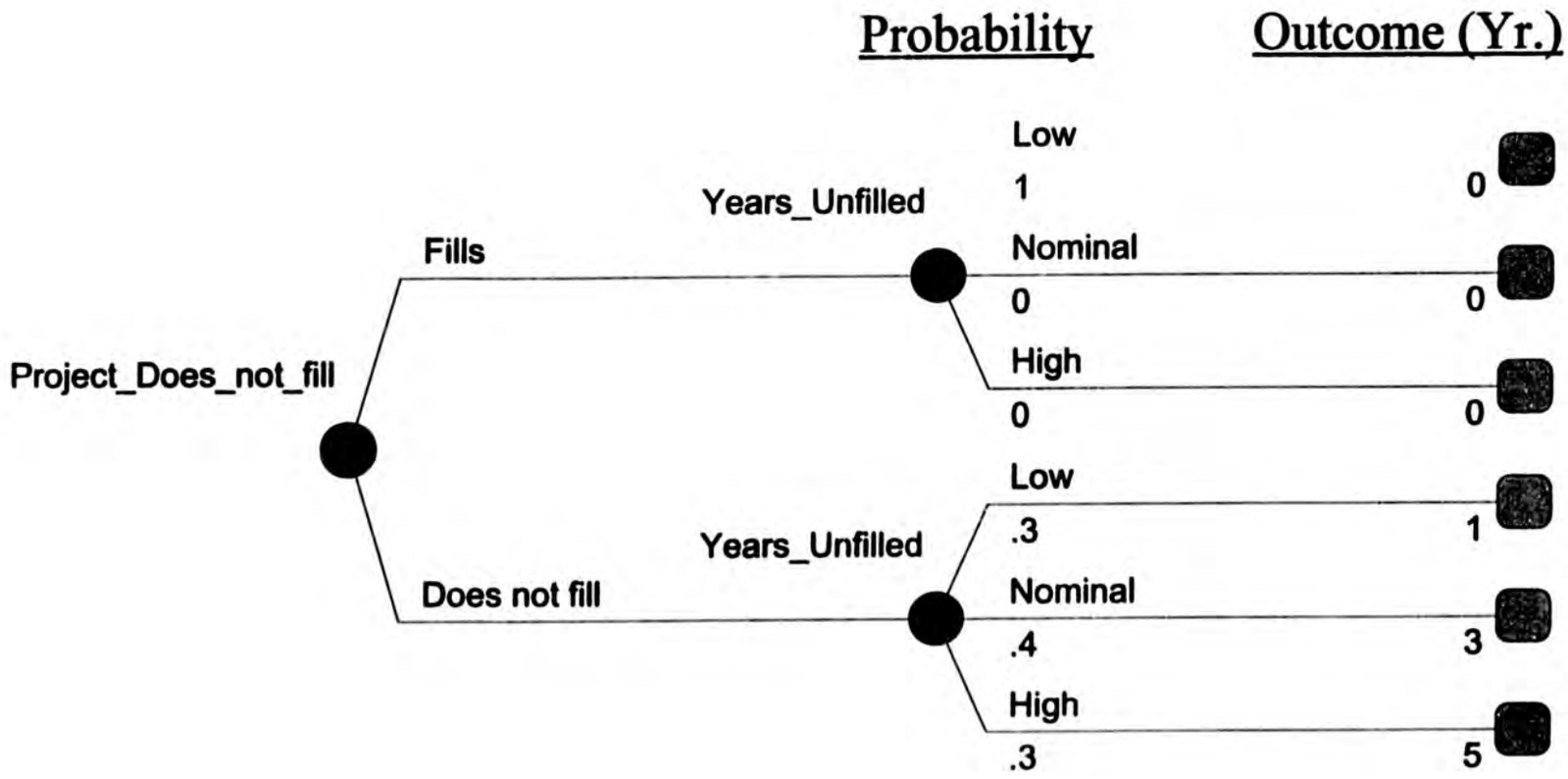


Uncertainty Branch



Note: Numbers on left represent branch probability.
Numbers on right represent value (years, $, %, etc…)

Uncertainty Branch



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Numbers on right represent value (years, $, %, etc…)

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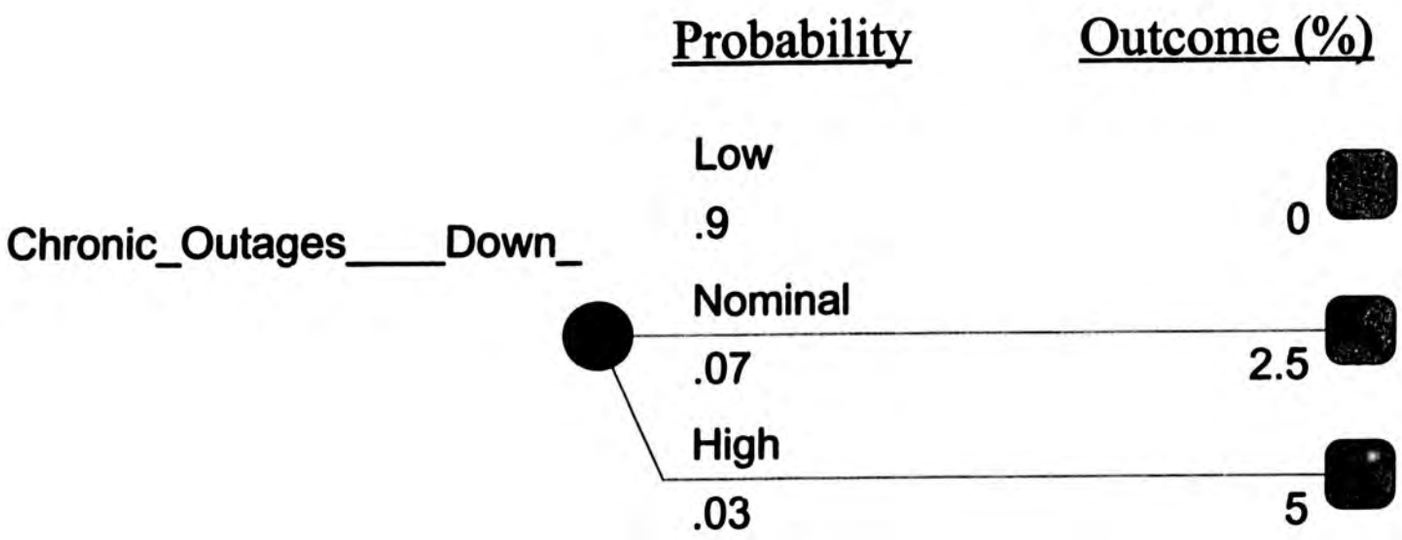

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Numbers on right represent value (years, $, %, etc…)

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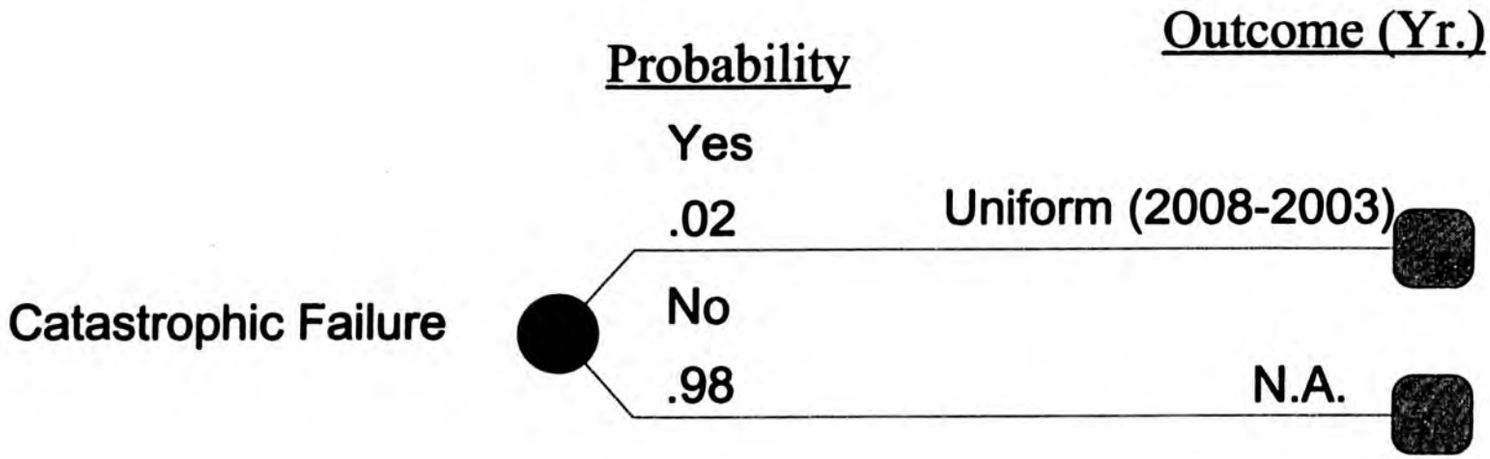

Note: Numbers on left represent branch probability.
Numbers on right represent value (years, $, %, etc…)

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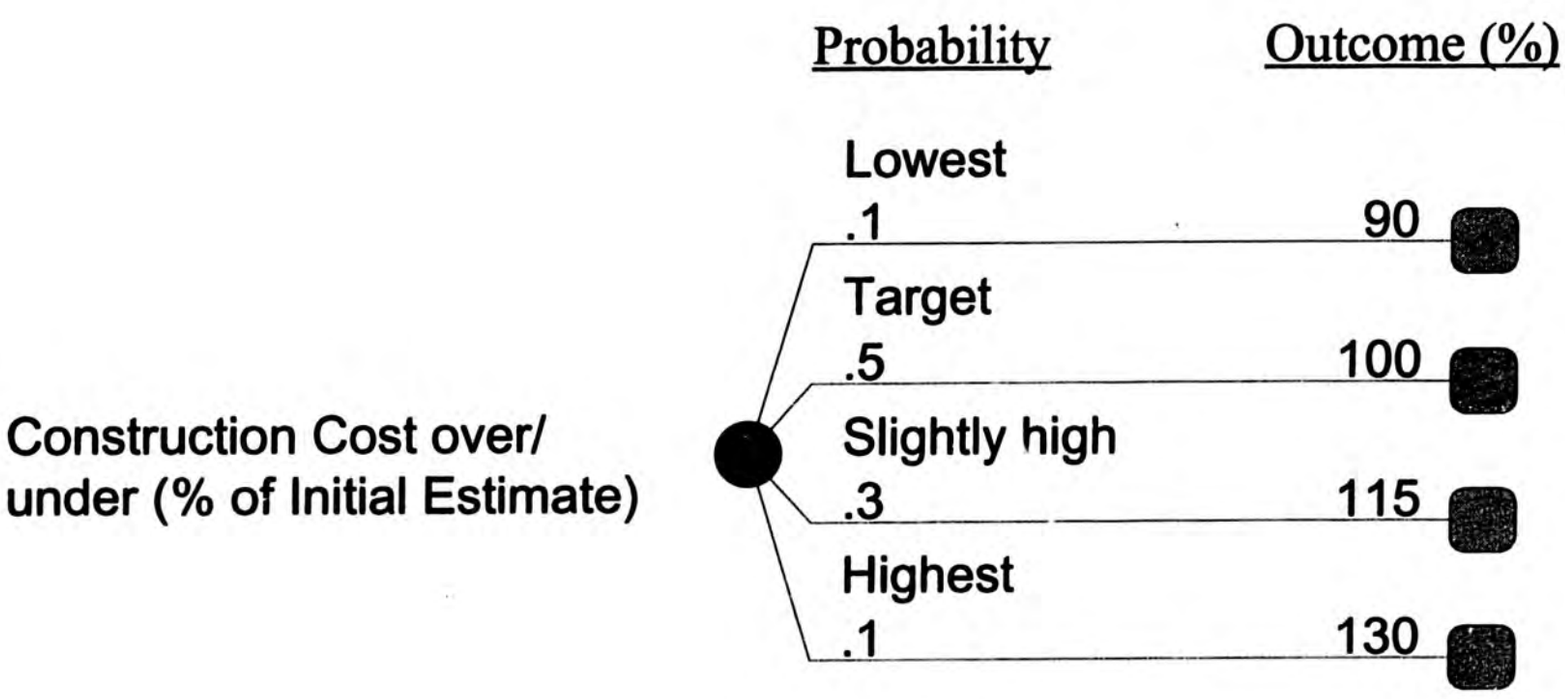

Note: Numbers on left represent branch probability.
Numbers on right represent value (years, $, %, etc…)

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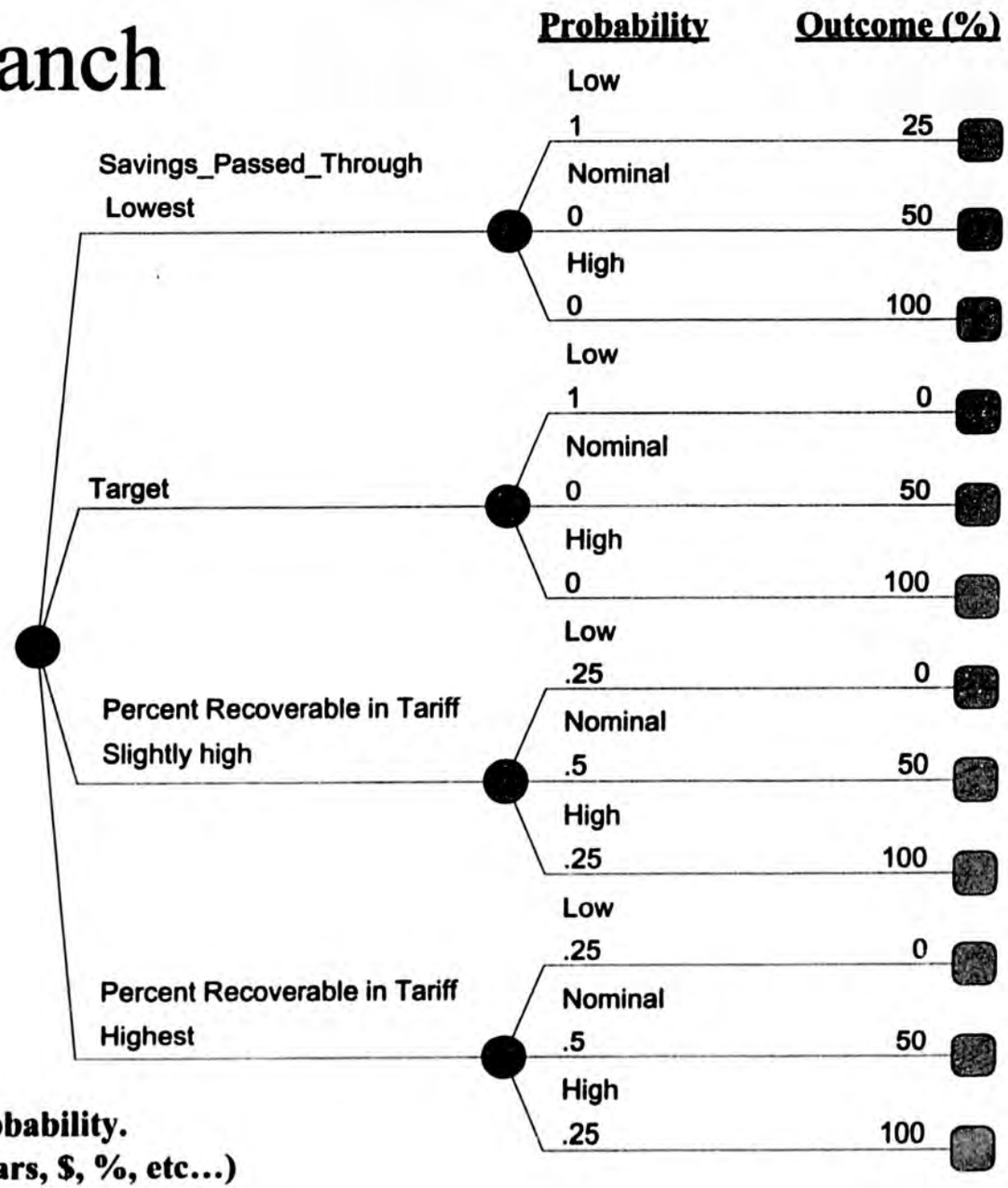

Note: **Numbers on left represent branch probability.**
Numbers on right represent value (years, $, %, etc...)

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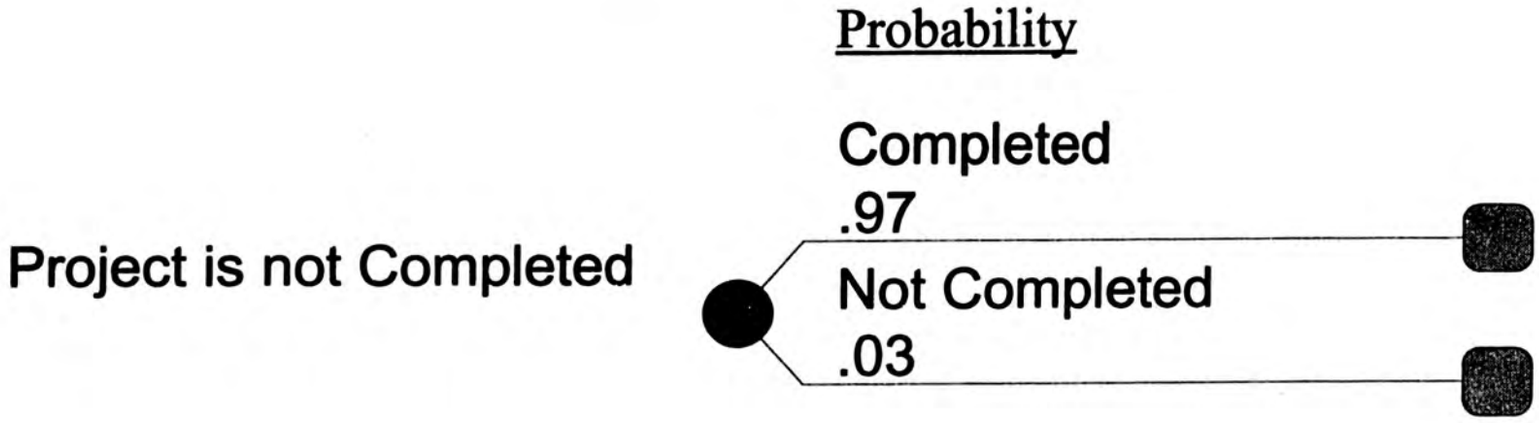

Note: Numbers on left represent branch probability.

Appendix C
Sample Model Input and Output

TABLE 2

Alaska Gas Pipeline

Financial Analysis of Ownership Participation by the State of Alaska

Investment Costs

(Billions of Dollars)

01/25/02

Year	Cumulative Through 2001	2002	2003	2004	2005	2006	2007	2008	Total
Planning and Construction									
Expenditure profile	2%	2%	10%	16%	22%	23%	18%	7%	100%
Billions of 2001 Dollars	0.21	0.22	0.91	1.40	1.98	2.06	1.61	0.62	9.00
Billions of Nominal $	0.21	0.23	0.96	1.51	2.18	2.33	1.87	0.73	10.01
AFUDC	0.20	0.18	0.63	0.80	0.88	0.68	0.35	0.06	3.78
Total Cost	0.41	0.41	1.59	2.30	3.06	3.01	2.21	0.80	13.79
									13.79
Allocation from Producers	2%	2%	10%	15%	21%	22%	17%	7%	95%
Adjusted	2.3%	2.5%	10.1%	15.5%	22.0%	22.9%	17.9%	6.9%	100.0%

TABLE 3
Alaska Gas Pipeline
Financial Analysis of Ownership
Participation by the State of Alaska

Tariff and Base Internal Rate of Return Projections
Dollar Amounts in Millions unless Otherwise Indicated

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Tariff Calculation (North Slope to Alberta)													
Rate Base													
Beginning of Year		1,724	1,655	1,586	1,517	1,448	1,379	1,310	1,241	1,172	1,103	1,034	965
less: Depreciation		69	69	69	69	69	69	69	69	69	69	69	69
End of Year	1,724	1,655	1,586	1,517	1,448	1,379	1,310	1,241	1,172	1,103	1,034	965	896
Property Tax Value													
Replacement Cost New Less Depreciation		1,724	1,696	1,666	1,633	1,598	1,560	1,519	1,475	1,428	1,378	1,324	1,266
US Revenue Requirements													
Operation and Maintenance		15	15	16	16	17	17	17	18	18	19	19	20
Depreciation		34	34	34	34	34	34	34	34	34	34	34	34
Property Tax		17	17	17	16	16	16	15	15	14	14	13	13
US Income Taxes		16	(12)	(7)	(3)	1	4	5	4	3	2	2	1
Interest Expense		45	43	42	40	38	36	34	33	31	29	27	25
Return to Equity		31	30	29	27	26	25	24	22	21	20	19	17
Total		159	128	130	131	132	132	130	126	122	118	114	110
Canadian Revenue Requirements													
Operation and Maintenance		15	15	16	16	17	17	17	18	18	19	19	20
Depreciation		34	34	34	34	34	34	34	34	34	34	34	34
Property Tax		17	17	17	16	16	16	15	15	14	14	13	13
Canadian Income Taxes		25	13	13	13	14	14	14	15	15	15	15	15
Interest Expense		45	43	42	40	38	36	34	33	31	29	27	25
Return to Equity		31	30	29	27	26	25	24	22	21	20	19	17
Total		168	153	150	148	145	142	140	137	134	131	128	125
Total Revenue Requirements													
Operation and Maintenance		30	31	32	32	33	34	35	36	37	38	39	40
Depreciation		69	69	69	69	69	69	69	69	69	69	69	69
Property Tax		34	34	33	33	32	31	30	30	29	28	26	25
Income Taxes		40	0	6	10	14	18	19	19	18	17	17	16
Interest Expense		90	87	83	80	76	72	69	65	62	58	54	51
Return to Equity		62	60	57	55	52	50	47	45	42	40	37	35
Total Revenue Requirements		327	280	280	279	277	274	270	263	256	249	242	235

TABLE 3
Alaska Gas Pipeline
Financial Analysis of Ownership
Participation by the State of Alaska

Tariff and Base Internal Rate of Return Projections
Dollar Amounts in Millions unless Otherwise Indicated

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Tariff Calculation (North Slope to Alberta)													
Rate Base													
Beginning of Year	896	827	758	689	620	552	483	414	345	276	207	138	69
less: Depreciation	69	69	69	69	69	69	69	69	69	69	69	69	69
End of Year	827	758	689	620	552	483	414	345	276	207	138	69	(0)
Property Tax Value													
Replacement Cost New Less Depreciation	1,205	1,140	1,072	998	921	839	753	661	565	463	356	243	125
US Revenue Requirements													
Operation and Maintenance	20	21	21	22	22	23	24	24	25	25	26	27	27
Depreciation	34	34	34	34	34	34	34	34	34	34	34	34	34
Property Tax	12	11	11	10	9	8	8	7	6	5	4	2	1
US Income Taxes	(0)	(1)	(2)	15	32	31	30	29	28	28	27	26	25
Interest Expense	24	22	20	18	16	14	13	11	9	7	5	4	2
Return to Equity	16	15	14	12	11	10	9	7	6	5	4	2	1
Total	106	102	98	112	125	121	117	113	108	104	100	95	91
Canadian Revenue Requirements													
Operation and Maintenance	20	21	21	22	22	23	24	24	25	25	26	27	27
Depreciation	34	34	34	34	34	34	34	34	34	34	34	34	34
Property Tax	12	11	11	10	9	8	8	7	6	5	4	2	1
Canadian Income Taxes	15	15	15	15	15	15	14	14	14	14	14	13	13
Interest Expense	24	22	20	18	16	14	13	11	9	7	5	4	2
Return to Equity	16	15	14	12	11	10	9	7	6	5	4	2	1
Total	122	118	115	112	108	105	101	98	94	90	87	83	79
Total Revenue Requirements													
Operation and Maintenance	41	42	43	44	45	46	47	48	49	51	52	53	55
Depreciation	69	69	69	69	69	69	69	69	69	69	69	69	69
Property Tax	24	23	21	20	18	17	15	13	11	9	7	5	2
Income Taxes	15	14	13	30	47	46	45	44	42	41	40	39	38
Interest Expense	47	43	40	36	33	29	25	22	18	14	11	7	4
Return to Equity	32	30	27	25	22	20	17	15	12	10	7	5	2
Total Revenue Requirements	228	221	213	224	234	226	218	211	202	195	186	178	170

TABLE 3

Alaska Gas Pipeline

Financial Analysis of Ownership

Participation by the State of Alaska

Tariff and Base Internal Rate of Return Projections

Dollar Amounts in Millions unless Otherwise Indicated

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Revenue Requirement per MMBtu														
US			0.85	0.68	0.69	0.70	0.70	0.71	0.70	0.67	0.65	0.63	0.61	0.59
Canadian			0.90	0.82	0.80	0.79	0.77	0.76	0.75	0.73	0.71	0.70	0.68	0.67
Total			1.74	1.50	1.49	1.49	1.48	1.47	1.44	1.40	1.37	1.33	1.29	1.26
Levelized Tariff Estimates														
Nominal Tariffs (Current $/MMBtu)														
Total Tariff	1.38													
Included Income Taxes	0.11													
Tariff w/o Inc Taxes	1.27													
Added Cost of Inc Taxes														
Total	8.7%													
Federal only	6.7%													
Monthly Cost	21.23													
Levelized Tariff (Constant 2001$)														
Total Tariff			1.43	1.20	1.17	1.13	1.10	1.06	1.02	0.97	0.92	0.87	0.83	0.79
Levelized	0.92													
Projected Income, Cash Flow, and Internal Rate of Return														
Income Statement														
Revenues														
Tariff[1] ($/MMBtu)			1.74	1.50	1.49	1.49	1.48	1.47	1.44	1.40	1.37	1.33	1.29	1.26
Annual Sales (BCF)			1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080
Btu per cubic foot			327	280	280	279	277	274	270	263	256	249	242	235
Total Revenues														
Operating Expenses														
Operation and Maintenance			30	31	32	32	33	34	35	36	37	38	39	40
Depreciation			69	69	69	69	69	69	69	69	69	69	69	69
Property Tax			34	34	33	33	32	31	30	30	29	28	26	25
Total Operating Expenses			134	134	134	134	134	134	134	134	134	134	134	134
Operating Income before Income Tax			193	147	146	145	143	140	135	129	122	115	108	101
US Income Taxes			15.64	(12.30)	(7.45)	(3 20)	0.57	3.91	5.03	4.16	3.24	2.43	1.50	0.70
Canadian Income Taxes			24.85	12.58	13.06	13.49	13.86	14.18	14.44	14.66	14.83	14.96	15.04	15.09
Operating Income after Income Taxes			153	146	140	134	128	122	116	110	104	98	92	85
Interest Expense			90	87	83	80	76	72	69	65	62	58	54	51
Net Income			62	60	57	55	52	50	47	45	42	40	37	35

TABLE 3
Alaska Gas Pipeline
Financial Analysis of Ownership
Participation by the State of Alaska

Tariff and Base Internal Rate of Return Projections
Dollar Amounts in Millions unless Otherwise Indicated

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Revenue Requirement per MMBtu														
US		0.57	0.55	0.52	0.60	0.67	0.65	0.62	0.60	0.58	0.56	0.53	0.51	0.49
Canadian		0.65	0.63	0.61	0.60	0.58	0.56	0.54	0.52	0.50	0.48	0.46	0.44	0.42
Total		1.22	1.18	1.14	1.19	1.25	1.21	1.17	1.12	1.08	1.04	1.00	0.95	0.91
Levelized Tariff Estimates														
Nominal Tariffs (Current $/MMBtu)														
Total Tariff	1.38													
Included Income Taxes	0.11													
Tariff w/o Inc Taxes	1.27													
Added Cost of Inc Taxes														
Total	8.7%													
Federal only	6.7%													
Monthly Cost	21.23													
Levelized Tariff (Constant 2001$)														
Total Tariff		0.74	0.70	0.66	0.68	0.69	0.65	0.61	0.58	0.54	0.51	0.47	0.44	0.41
Levelized	0.92													

Projected Income, Cash Flow, and Internal Rate of Return

Income Statement													
Revenues													
Tariff[1] ($/MMBtu)	1.22	1.18	1.14	1.19	1.25	1.21	1.17	1.12	1.08	1.04	1.00	0.95	0.91
Annual Sales (BCF)	173	173	173	173	173	173	173	173	173	173	173	173	173
Btu per cubic foot	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080
Total Revenues	228	221	213	224	234	226	218	211	203	195	186	178	170
Operating Expenses													
Operation and Maintenance	41	42	43	44	45	46	47	48	49	51	52	53	55
Depreciation	69	69	69	69	69	69	69	69	69	69	69	69	69
Property Tax	24	23	21	20	18	17	15	13	11	9	7	5	2
Total Operating Expenses	134	133	133	133	132	132	131	130	130	129	128	127	126
Operating Income before Income Tax	94	87	80	91	102	94	87	80	73	66	58	51	44
US Income Taxes	(0.23)	(1.03)	(1.96)	14.98	31.86	30.99	30.13	29.26	28.39	27.53	26.66	25.80	24.93
Canadian Income Taxes	15.10	15.07	15.02	14.92	14.80	14.65	14.47	14.27	14.04	13.78	13.51	13.21	12.89
Operating Income after Income Taxes	79	73	67	61	55	49	43	37	31	24	18	12	6
Interest Expense	47	43	40	36	33	29	25	22	18	14	11	7	4
Net Income	32	30	27	25	22	20	17	15	12	10	7	5	2

TABLE 3
Alaska Gas Pipeline
Financial Analysis of Ownership
Participation by the State of Alaska

Tariff and Base Internal Rate of Return Projections
Dollar Amounts in Millions unless Otherwise Indicated

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
US Income Taxes													
Revenues		159	128	130	131	132	132	130	126	122	116	114	110
Operation and Maintenance		15	15	16	16	17	17	17	18	18	19	19	20
Depreciation (for Taxes)		43	82	74	66	60	54	51	51	51	51	51	51
Property Tax		17	17	17	16	16	16	15	15	14	14	13	13
Interest Expense		45	43	42	40	38	36	34	33	31	29	27	25
Taxable Income		38	(30)	(18)	(8)	1	10	12	10	8	6	4	2
State of Alaska Tax		4	(3)	(2)	(1)	0	1	1	1	1	1	0	0
Federal Tax		12	(9)	(6)	(2)	0	3	4	3	2	2	1	1
Total US Income Tax		16	(12)	(7)	(3)	1	4	5	4	3	2	2	1
Canadian Income Taxes													
Revenues		168	153	150	148	145	142	140	137	134	131	128	125
Operation and Maintenance		15	15	16	16	17	17	17	18	18	19	19	20
Depreciation (for Taxes)		22	42	40	38	36	34	33	31	29	28	26	25
Property Tax		17	17	17	16	16	16	15	15	14	14	13	13
Interest Expense		45	43	42	40	38	36	34	33	31	29	27	25
Taxable Income		69	35	36	37	38	39	40	41	41	41	42	42
Total Canadian Income Tax		25	13	13	13	14	14	14	15	15	15	15	15
Cash Flow													
Capital Investment	(1,724)												
Operating Income		153	146	140	134	128	122	116	110	104	98	92	85
plus Depreciation		69	69	69	69	69	69	69	69	69	69	69	69
Net Cash Flow	(1,724)	221	215	209	203	197	191	185	179	173	167	160	154
Interest expense		90	87	83	80	76	72	69	65	62	58	54	51
Principal payment		48	48	48	48	48	48	48	48	48	48	48	48
Principal and interest payment	(1,206)	139	135	132	128	124	121	117	113	110	106	103	99
Net Cash Flow after Interest Payment	(517)	83	80	78	75	73	70	68	65	63	60	58	55
IRR–Total Capital	8.85%												
IRR–Debt	7.50%												
IRR–Equity	12.00%												

[1] The tariff shown is based on the simplifying assumption that the tariff will be equal to the annual revenue requirements. In fact the tariff will be negotiated to be fixed for many years base on a levelizing formul

TABLE 3
Alaska Gas Pipeline
Financial Analysis of Ownership
Participation by the State of Alaska

Tariff and Base Internal Rate of Return Projections
Dollar Amounts in Millions unless Otherwise Indicated

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
US Income Taxes													
Revenues	106	102	98	112	125	121	117	113	108	104	100	95	91
Operation and Maintenance	20	21	21	22	22	23	24	24	25	25	26	27	27
Depreciation (for Taxes)	51	51	51	25	-	-	-	-	-	-	-	-	-
Property Tax	12	11	11	10	9	8	8	7	6	5	4	2	1
Interest Expense	24	22	20	18	16	14	13	11	9	7	5	4	2
Taxable Income	(1)	(3)	(5)	36	77	75	73	71	69	67	65	63	61
State of Alaska Tax	(0)	(0)	(0)	3	7	7	7	7	6	6	6	6	6
Federal Tax	(0)	(1)	(2)	12	25	24	23	23	22	21	21	20	19
Total US Income Tax	(0)	(1)	(2)	15	32	31	30	29	28	28	27	26	25
Canadian Income Taxes													
Revenues	122	118	115	112	108	105	101	98	94	90	87	83	79
Operation and Maintenance	20	21	21	22	22	23	24	24	25	25	26	27	27
Depreciation (for Taxes)	24	23	22	20	19	18	18	17	16	15	14	14	13
Property Tax	12	11	11	10	9	8	8	7	6	5	4	2	1
Interest Expense	24	22	20	18	16	14	13	11	9	7	5	4	2
Taxable Income	42	42	42	41	41	41	40	39	39	38	37	37	36
Total Canadian Income Tax	15	15	15	15	15	15	14	14	14	14	14	13	13
Cash Flow													
Capital Investment	79	73	67	61	55	49	43	37	31	24	18	12	6
Operating Income	69	69	69	69	69	69	69	69	69	69	69	69	69
plus Depreciation	148	142	136	130	124	118	112	106	99	93	87	81	75
Net Cash Flow													
Interest expense	47	43	40	36	33	29	25	22	18	14	11	7	4
Principal payment	48	48	48	48	48	48	48	48	48	48	48	48	48
Principal and Interest payment	95	92	88	84	81	77	74	70	66	63	59	55	52
Net Cash Flow after Interest Payment	53	50	48	46	43	41	38	36	33	31	28	26	23

IRR--Total Capital
IRR--Debt
IRR--Equity

[1] The tariff shown is based on the simplifying assumption that the tariff will be equal to the annual revenue requirements. In fact the tariff will be negotiated to be fixed for many years base on a levelizing fo

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ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

Official Business

Senator John Torgerson, Chair
Senator Rick Halford
Senator Pete Kelly
Senator Johnny Ellis

Representative Joe Green, Vice-Chair
Representative Brian Porter
Representative Scott Ogan
Representative John Davies

MEMORANDUM

To: **Members of the Joint Committee on Natural Gas Pipelines**

From: **Senator John Torgerson, Chair**

Re: **Hogan and Hartson report on Federal Legislative Developments Related to Natural Gas Pipelines**

Date: **March 18, 2002**

Senate Energy Debate

During the week of March 11, the Senate continued consideration of S. 517, the energy policy legislation. Vehicle fuel economy, energy trading, and electric utility deregulation (including provisions related to the Public Utility Holding Company Act and the Public Utility Regulatory Policies Act) were the primary topics for amendments last week.

Only one amendment related to natural gas was raised. On March 14, the Senate adopted amendment # 3014, which would establish within the Department of Justice an Office of Consumer Affairs to "represent the interests of energy customers on matters concerning rates or service of public utilities and natural gas companies under the jurisdiction" of FERC at: (1) FERC hearings, (2) judicial proceedings, and (3) at hearings or proceedings of other federal regulatory agencies and commissions. The text of amendment #3014 is reprinted below.

On Senate floor Friday, March 15, Senators Murkowski (R-AK) and Bingaman (D-NM) briefly discussed their ongoing efforts in working together to develop further amendments related to the proposed Alaska natural gas

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pipeline. Senator Murkowski said that language is being developed that "sets procedures in place for allocating initial gas capacity of the pipeline and for any subsequent expansions that might be warranted based on new discoveries or additional needs in the Lower 48 markets." Senator Bingaman added that additional amendments are being developed that are intended to lower the financial risk of the proposed pipeline project and to enhance the ability of the proposed Pipeline Coordinator to streamline the federal and state permitting process.

Early this week, the Senate will set aside the energy bill in order to consider the House passed campaign finance reform bill. It is difficult to say exactly how long the Senate will need to spend on the campaign finance bill, but it is likely to be Wednesday or Thursday of this week before the Senate is able to return to consideration of the energy bill. As a result, the Senate's debate of the energy bill is expected to continue after the upcoming two-week spring recess ends (March 25th through April 7th).

House Hearing on Pipeline Safety

The Subcommittee on Energy and Air Quality of the House Energy and Commerce Committee is scheduled to hold a hearing March 19 on reauthorization of the Natural Gas Pipeline Safety Act and the Hazardous Liquid Pipeline Safety Act.

House Science Committee Bill on Pipeline R&D

The House Science Committee is scheduled to hold a markup on H.R. 3929, a bill sponsored by Representatives Ralph Hall (D-TX) and Lamar Smith (R-TX) that would authorize $100 million over five years for pipeline R&D at three agencies: the Department of Transportation; the Department of Energy; and the National Institute of Standards and Technology. The R&D under this bill would focus on pipeline materials, stress and fracture analysis, leak detection technologies, and pipeline surveillance. The Committee conducted a hearing on the bill last week.

Senate Amendment approved March 14.

SA 3014. Mr. WYDEN (for himself and Mrs. FEINSTEIN) submitted an amendment intended to be proposed to amendment SA 2917 proposed by Mr. DASCHLE (for himself and Mr. BINGAMAN) to the bill (S. 517) to authorize funding the Department of Energy to enhance its mission areas through technology transfer and partnerships for fiscal years 2002 through 2006, and for other purposes; as follows:

On page 57, between lines 17 and 18, insert the following:

SEC. 253. OFFICE OF CONSUMER ADVOCACY.

(a) **DEFINITIONS.**--In this section:

(1) **COMMISSION.**--The term ``Commission'' means the Federal Energy Regulatory Commission.

(2) **ENERGY CUSTOMER.**--The term ``energy customer'' means a residential customer or a small commercial customer that receives products or services from a public utility or natural gas company under the jurisdiction of the Commission.

(3) **NATURAL GAS COMPANY.**--The term ``natural gas company'' has the meaning given the term in section 2 of the Natural Gas Act (15 U.S.C. 717a), as modified by section 601(a) of the Natural Gas Policy Act of 1978 (15 U.S.C. 3431(a)).

(4) **OFFICE.**--The term ``Office'' means the Office of Consumer Advocacy established by subsection (b)(1).

(5) **PUBLIC UTILITY.**--The term ``public utility'' has the meaning given the term in section 201(e) of the Federal Power Act (16 U.S.C. 824(e)).

(6) **SMALL COMMERCIAL CUSTOMER.**--The term ``small commercial customer'' means a commercial customer that has a peak demand of not more than 1,000 kilowatts per hour.

(b) **OFFICE.**--

(1) **ESTABLISHMENT.**--There is established within the Department of Justice the Office of Consumer Advocacy.

(2) **DIRECTOR.**--The Office shall be headed by a Director to be appointed by the President, by and with the advice and consent of the Senate.

(3) **DUTIES.**--The Office may represent the interests of energy customers on matters concerning rates or service of public utilities and natural gas companies under the jurisdiction of the Commission--

(A) at hearings of the Commission;

(B) in judicial proceedings in the courts of the United States;

(C) at hearings or proceedings of other Federal regulatory agencies and commissions;

Senator Halford

bp

file

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

March 13, 2002

The Honorable John Torgerson
Alaska State Senator
State Capitol, Room 427
Juneau, AK 99801-1182

Dear Senator Torgerson:

I am writing in reference to your letter dated February 20. Thank-you for your expressed interest in considering fiscal clarity with respect to an Alaska North Slope gas project.

A simple, clear and predictable fiscal framework in Alaska is indeed a vital element in creating what we term a viable government framework for investment. We have talked before about the essential ingredients necessary to progress a project to the next stage, including:

- Passage of U.S. federal enabling legislation in a form that adequately addresses risks and issues identified by the Alaska North Slope producers.
- Achieving clarity and predictability around the Canadian First Nations and National Energy Board regulatory process.
- Achieving agreement with the State of Alaska around a clear, simple and predictable fiscal framework so that the enormous investment with its associated long payback can be contemplated on the understanding the rules won't change.
- Identifying a commercially viable project where project costs and risks do not outweigh prospective rewards.

There are challenges in all these areas but progress is being made. A U.S. senate energy bill with Alaska gas provisions is now gaining some momentum. We continue to engage with First Nations and Canadian regulators toward an efficient and predictable regulatory process for a project of this magnitude. And we are identifying a number of cost reduction ideas to help make Alaska gas cost competitive in the market. It would certainly be our hope and desire that we might also begin to make progress on fiscal clarity in Alaska as well.

Last summer, BP, with our partners, outlined to the joint committee the importance of fiscal clarity in Alaska to support prospective future investments on gas. We have also met with members of the Administration on the same subject.

BP also independently hosted visits for staff from the state's departments of Natural Resources, Revenue and Labor to our gas marketing office in Calgary. This offered an opportunity to address in more detail how gas is marketed in and out of Alberta. Understanding how gas markets operate is a necessary foundation to agree how gas prices for royalty and production taxes should be determined.

BP has discussed with state staff the concepts BP feels would make the fiscal framework around gas clear and simple to avoid unnecessary disputes in the future. Clarity and simplicity are essential. We cannot replay with gas the painful process of costly litigation and after-the-fact settlements that were part of the first twenty years of Alaska North Slope oil production. And, of course, clear and predictable gas taxation cannot come at the expense of changing oil taxes.

A process to achieve a mutually agreeable fiscal framework will require time, energy and dedication from the tax and royalty experts within the state and industry. BP is fully prepared to dedicate resources to this effort at any time. However, to date, progressing fiscal clarity has not been a state priority. Some have suggested that industry simply present to the state "what it wants." I do not believe this a viable path to achieving our goals. Rather, we would see a collaborative approach, with tax and royalty professionals from the state and industry jointly addressing the issues.

The first step in this process is having state and industry leadership mutually agree that they want to make fiscal predictability a priority so they can direct their respective professionals to achieve that goal. I believe once this occurs, real progress can be made. Ultimately, any solution will clearly require consensus of both the Administration and the Legislature.

I would like to be clear: BP has not been requesting fundamental changes to the state tax regime for gas nor have we requested any specific incentives. However, we are requesting simplicity, clarity and predictability that will preclude future increases in state take through tax and royalty administration. Such clarity will be necessary before considering moving this project to the next phase of funding or activity.

We are aware some in state government have discussed actions that could enhance overall economics such as reducing tax regressivity or providing ad valorem tax holidays. BP will continue to evaluate project commerciality, as we do all projects around the world, against whatever fiscal policies governments have in place. Clearly, government actions that either reduce costs or risks can assist a gas pipeline project, or any other investment for that matter. However, it is for the state to decide what investment climate it wishes to create for investors. BP is available anytime to discuss and evaluate any changes the state may be considering and how they may impact future investment decisions.

As you mentioned in your letter, the joint study team has essentially completed the current phase of work. Contractors have been notified and company staff have been or are being redeployed. This phase of activity, with over 1,000,000 man-hours of work, has provided us a much more in-depth understanding of the project and provides a strong technical underpinning for any future activity.

BP will maintain a small core team of company staff to progress activities we view as essential building blocks for a successful project including cost and cost risk reduction studies, progressing regulatory efficiency in the U.S. and Canada, and fiscal predictability in Alaska.

We will be communicating results of our work in the near future and I expect these results will be broadly consistent with what we have been communicating for the past several months. When this information is available, it is certainly our plan to review it with you directly.

As always, please free to contact me at any time.

Sincerely,

Ken Konrad
Vice President – Alaska Gas

ALASKA STATE LEGISLATURE

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Representative John Davies

MEMORANDUM

To: Members of the Joint Committee on Natural Gas Pipelines

From: Senator John Torgerson, Chair

Date: March 20, 2002

Re: Response from the producers on fiscal certainty

During the many hearings we have held over the last year, we have continuously heard from the producers that state fiscal stability/certainty is a necessity for a commercially viable gas pipeline project. On March 1, 2002, I sent a letter to BP, Phillips and ExxonMobile with regard to fiscal certainty. I have now received a response from all three and I am attaching the letters for your review.

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Senator Johnny Ellis

Representative Joe Green, Vice-Chair
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Representative Scott Ogan
Representative John Davies

March 1, 2002

Ken Konrad, Sr.
Vice President Business Unit Leader Alaska Gas
BP Exploration Inc.
P.O. Box 196612
Anchorage, AK 99519-6612

Dear Mr. Konrad:

Last July, you told the Legislature's Joint Committee on Natural Gas Pipelines that the Producers intended to "initiate a dialogue between the State and Producers regarding fiscal stability/certainty" relating to an Alaskan natural gas pipeline project. You also said "your objective was to have key terms understood prior to the January legislative session." Repeatedly, you told the Committee, the press, and me that fiscal certainty with the State is a "must have." It is now more than six months later and January has come and gone. Yet, to my knowledge, you have not initiated any dialogue with the Legislature about fiscal stability/certainty, much less reached an understanding of key terms.

Given that you said you would have requests for the Legislature to help make the project happen, the Joint Committee readied itself to act. During the interim, we held several hearings giving you the opportunity to express your views. We assembled a team of experts to evaluate any proposals that you might have, including proposals relating to issues other than certainty, like permitting and access.

We have repeatedly asked for information that would enable the Legislature to review requests for fiscal changes, but you have not provided much information. Initially, we expected financial information based upon your statements that you intended to have the results of your study by the end of last year. In December,

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however, Mr. McDowell of your Team was quoted as saying that the Team hoped that sometime early in the New Year it would "be in a position to share study results." Although I have received no formal notice, I now hear that you are disbanding your Team. So I am concerned when, if ever, you intend to share the results of your study with the Legislature and the people of Alaska. Your companies have repeatedly stated that it is important to develop a partnership between industry and the State. Partners, however, share information and concerns. This is not happening.

I realize that you are busy with federal energy legislation. Nevertheless, this merely heightens my concerns. You are making many proposals regarding federal legislation without discussing those proposals with the Legislature. In turn you seem to wonder why we are not more supportive of those proposals.

I encourage you to bring any proposals you have regarding fiscal stability/certainty to the Legislature as soon as possible. As I have repeatedly stated, the Legislature will not lead with incentives. If incentives are needed, you will need to provide the technical and economic data justifying those incentives. In addition, you will need to set forth the incentives that you have requested from other governments that will receive revenues from the project, including the United States government and Canadian federal, provincial, and territorial governments. Alaska will not be the only jurisdiction that provides incentives.

I expect to hear promptly. However, if I have not heard anything by March 15, I will begin to explore other options to get Alaska natural gas developed.

Sincerely,



Senator John Torgerson

ExxonMobil Production Company
P.O. Box 2180
Houston, Texas 77252-2180

Robert D. Schilhab
Manager, Alaska Gas Development

ExxonMobil
Production

March 8, 2002

Senator John Torgerson
Alaska State Legislature
Chair, Joint Committee on Natural Gas Pipelines
State Capitol, #427
Juneau, AK 99801

Dear Senator Torgerson,

I would like to thank you for your continued interest in progressing the commercialization of Alaska North Slope gas. All the issues you raised in your March 1, 2002 letter are important and I would like to have the opportunity to meet with you to discuss these and other gas pipeline items of interest at the earliest opportunity.

As you are aware, we are in the final stages of completing work on the one-year, $125 million Alaska gas pipeline study that was initiated in December 2000 by ExxonMobil, BP and Phillips. We expect to be able to share the results of our work by the end of March or early April.

I understand that you are particularly interested in what action ExxonMobil would expect from the Alaska Legislative this session related to a potential Alaska gas pipeline project. At this time, ExxonMobil does not expect to table any proposals on fiscal certainty, permitting or pipeline access this session.

In the meantime, I will work with your staff to set up a meeting as soon as possible.

Sincerely,

Robbie

RDS/MJM

bp

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900 East Benson Boulevard
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Anchorage, Alaska 99519-6612
(907) 561-5111

March 13, 2002

The Honorable John Torgerson
Alaska State Senator
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As always, please free to contact me at any time.

Sincerely,

Ken Konrad
Vice President – Alaska Gas

PHILLIPS Alaska, Inc.
A Subsidiary of PHILLIPS PETROLEUM COMPANY

P. O. BOX 100360
ANCHORAGE, ALASKA 99510-0360

Phone (907) 265-6517

Joseph P. Marushack
Vice President, ANS Gas Commercialization

March 15, 2002

The Honorable John Torgerson
State of Alaska
Senate
Juneau, AK 99801

RE: Phillips' Forward Strategy

Dear Senator Torgerson:

In response to your letter of March 1, 2002, we appreciate the Legislature's expressed desire to help make a gas pipeline project more commercially viable. I would like to address the topics in your letter in the context of Phillips' strategy.

Phillips is committed to trying to find and realize a commercially viable gas pipeline project to the L-48. Based upon the extensive evaluation conducted to date, we hope that we have been clear that project progress is currently impeded by unacceptable risks in the areas of permit timing, costs and future market prices. Therefore, Phillips is pursuing federal enabling legislation to reduce permit timing risks. We have also been working on federal fiscal legislation to mitigate risks that should be shared with those who will receive benefit from the development of ANS gas. This federal fiscal mechanism can be viewed similarly to an insurance policy: there may be no actual cost to the federal government, but it is critical to moving a project forward.

In these federal matters, we have been working with the State's Washington DC office, and we understand your DC counsel has also been involved. Further, we appreciate the support of our efforts as set forth in the Legislature's letter of February 21, 2002.

We have been focusing our efforts on the federal initiatives, as we believe that without them there is little urgency to progress State issues. However, we are hopeful that we will succeed in these efforts and are now moving towards more fully addressing the State requirements. There is a broad array of Alaskan fiscal modifications that could help improve a project's viability. In your letter, you correctly point out that it is still unclear which modifications are appropriate. That said, we believe that some concepts are beginning to take shape in the three basic state fiscal areas.

The first area is fiscal clarity, by which we mean the prospective establishment of mutually agreeable, clear rules as to how fiscal parameters will be established. For example, it is critical that the basis for determining the gas value upon which taxes and royalty are collected be known before project commitment. To date, we have had several meetings with the State's DOR and DNR concerning tax and royalty matters, respectively. Only with more discussion and analysis by the departments, will it become clear to what extent fiscal clarity requires any changes in statute. We are currently working on finalizing our views so that they can be shared with the State. We trust that the State will also be willing to fully engage in these discussions.

The second area is possible state fiscal incentives. We understand that you do not want the State leading in areas of fiscal initiatives. We would note that Phillips has also initially focused on federal opportunities. Still, we think it is appropriate to initiate dialog. The analysis done by AGPPT, and shared previously with you, suggests that the State will collect, through taxes and royalties, about the same economic rent as the U.S. Federal Government, if the project can be made viable. We believe that possible fiscal initiative(s) by the State would help address that risk and thus help make a project more viable.

At the February 4 meeting in Washington DC, several participants broached the idea of a temporary state and local Ad Valorem tax abatement for the project. Conceptually, this is a step in the right direction because Ad Valorem taxes are economic burdens early in project life, before revenues have been generated and also because they tend to exacerbate capital cost risks. In short, an Ad Valorem abatement would help reduce capital cost exposure and risk. It would also demonstrate to the Federal Government that the State is committed to helping make a project viable. While we believe that some state modifications could assist in developing the project, it will ultimately be a strategic policy decision on whether to enact project enhancing incentives. Ultimately, state fiscal modifications could improve project viability by reducing project risk.

The third area to consider is state fiscal certainty, by which we mean the establishment of a binding fiscal mechanism. We emphasize this because the State of Alaska is currently in a position to unilaterally degrade the project economics, relative to all of the other participants in the market, after the capital has been committed. We recognize there may be several alternatives that should be considered as fiscal certainty mechanisms and Phillips expects that the development of fiscal certainty will take some time before it is ready for legislative action.

Finally, you have asked when we intend to share results of the Joint Team work. I acknowledge and sincerely regret more time has passed than would have been expected, though I trust you will understand our primary focus has had to be on working the Federal issues while activities in Washington command our attention. However we

intend to share the results with you soon. We are finalizing the joint team results and will ask for a meeting to present our findings to you in the next few weeks.

In summary, our strategy is that if the federal legislation discussed above can be achieved, with no onerous mandates, and if meaningful progress can be achieved on state fiscal matters also as outlined above, Phillips remains committed to trying to move forward with the next phase of the project -- permitting the Southern Route.

If you have any questions or concerns, please do not hesitate to contact me directly at (907) 265-6517.

Sincerely,

Joe Marushack
Vice President, ANS Gas Commercialization
Phillips Alaska, Inc.

c: Members of the Joint Committee on Natural Gas Pipelines

SCOMM

129:11

ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

Official Business

Senator John Torgerson, Chair
Senator Rick Halford
Senator Pete Kelly
Senator Johnny Ellis

Representative Joe Green, Vice-Chair
Representative Brian Porter
Representative Scott Ogan
Representative John Davies

AGENDA

Joint Committee on Natural Gas Pipelines
April 10, 2002

1) **Update on Calgary Conference: Senator Torgerson**

2) **Update on Federal Legislation: Patrick Coughlin**

3) **Introduction of SB 360 - "Alaska Natural Gas Project Act"**

4) **Economic Models of Pipeline Projects: Dr. Doug Reynolds**

Session: January – May
State Capitol, #427
Juneau, AK 99801
Phone: 907-465-2828
Fax: 907-465-4779

Interim: May – December
35477 Kenai Spur Hwy., Suite 101A
Soldotna, AK 99669
Phone: 907-260-3041
Fax: 907-260-3044

4/10/02
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Economic Models of Pipeline Projects

Dr. Douglas B. Reynolds
Dr. Robert R. Logan
Dr. H. Charlie Sparks
Mr. Michael Backus

Model Building

- Looked at a large number of models
- Consulted and exchanged data with economists from the Department of Revenue, Department of Natural Resources and others to work out key issues involved
- Had updates every morning with Senator John Torgerson, Mr. Patrick Coughlin and other experts
- Modeled three simplified scenarios
- Other scenarios possible

Rate of Return Concept

Rate of return is a cash flow concept

Assume 1st year Equity Investment = -$100

Assume the following cash flow for each year

Yearly Revenue	**= +$30**
Yearly cost	**= -$10**
Yearly tax	**= -$10**
	+
Cash flow	**=+$10**

Cash flow per year

	Year 1	**Year 2**	**Year 3 ...**
-$100 Investment	**+$10**	**+$10**	**+$10**

ROR = 10%

- ROR is like interest from a Bank
- Higher ROR means a better investment and more profit
- If ROR is low, then firms choose alternative investments
- Producers want to sell gas to high ROR projects
- ROR affected by certain issues

Issue #1
Leveraging

- It is possible to pay for entire project out of pocket
  - called 100% equity financing
- It is possible to also leverage project with debt
  - example 70% Debt
    30% equity
- The ROR for the project is then the weighted average of the debt interest rate and the return on equity
- Most oil companies only compare projects with 100% equity

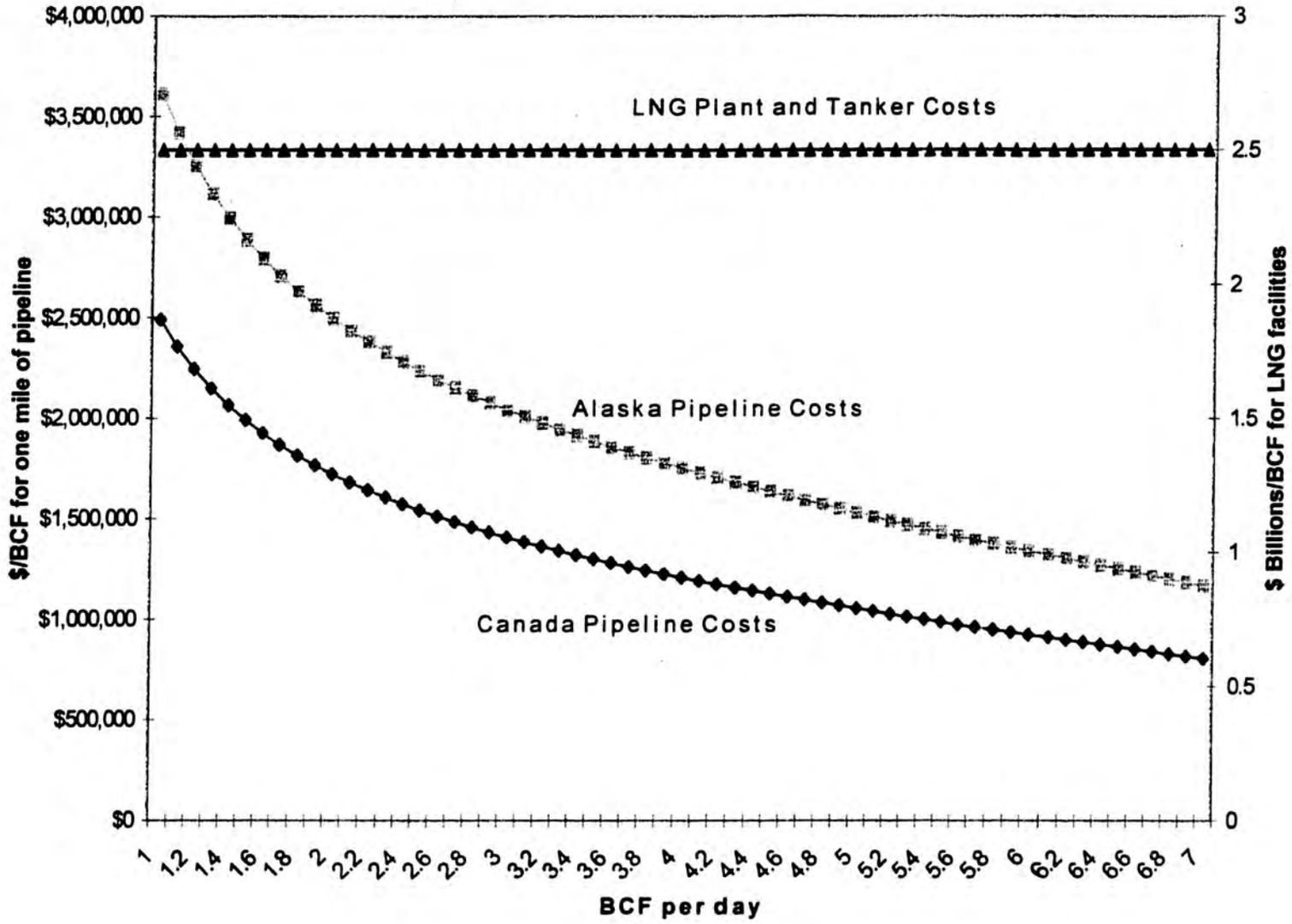
Issue #2
Natural Gas liquids (NGL)

- Some used as miscible injectants (MI), Heavy NGL's shipped in TAPS, lighter NGL's stripped and sold at the end of the gas pipeline
- NGL's more valuable than natural gas
- Selling more NGL's increases ROR
- High levels of NGL's not sustainable

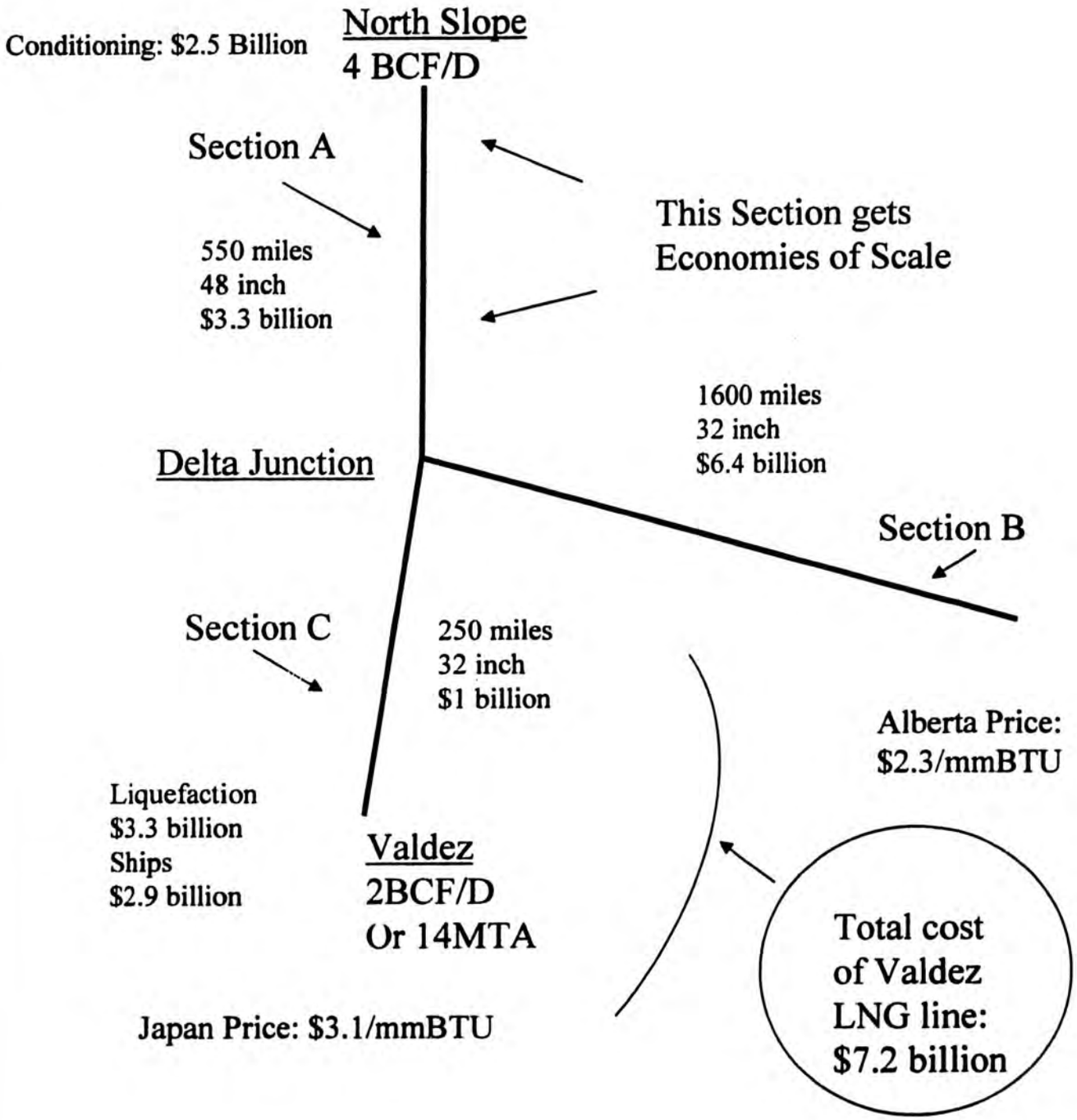
Issue #3
Economies of Scale

- The larger diameter the Pipeline the lower the costs
- Liquefied Natural Gas (LNG) plants and tankers have constant costs
- Lower costs increase ROR

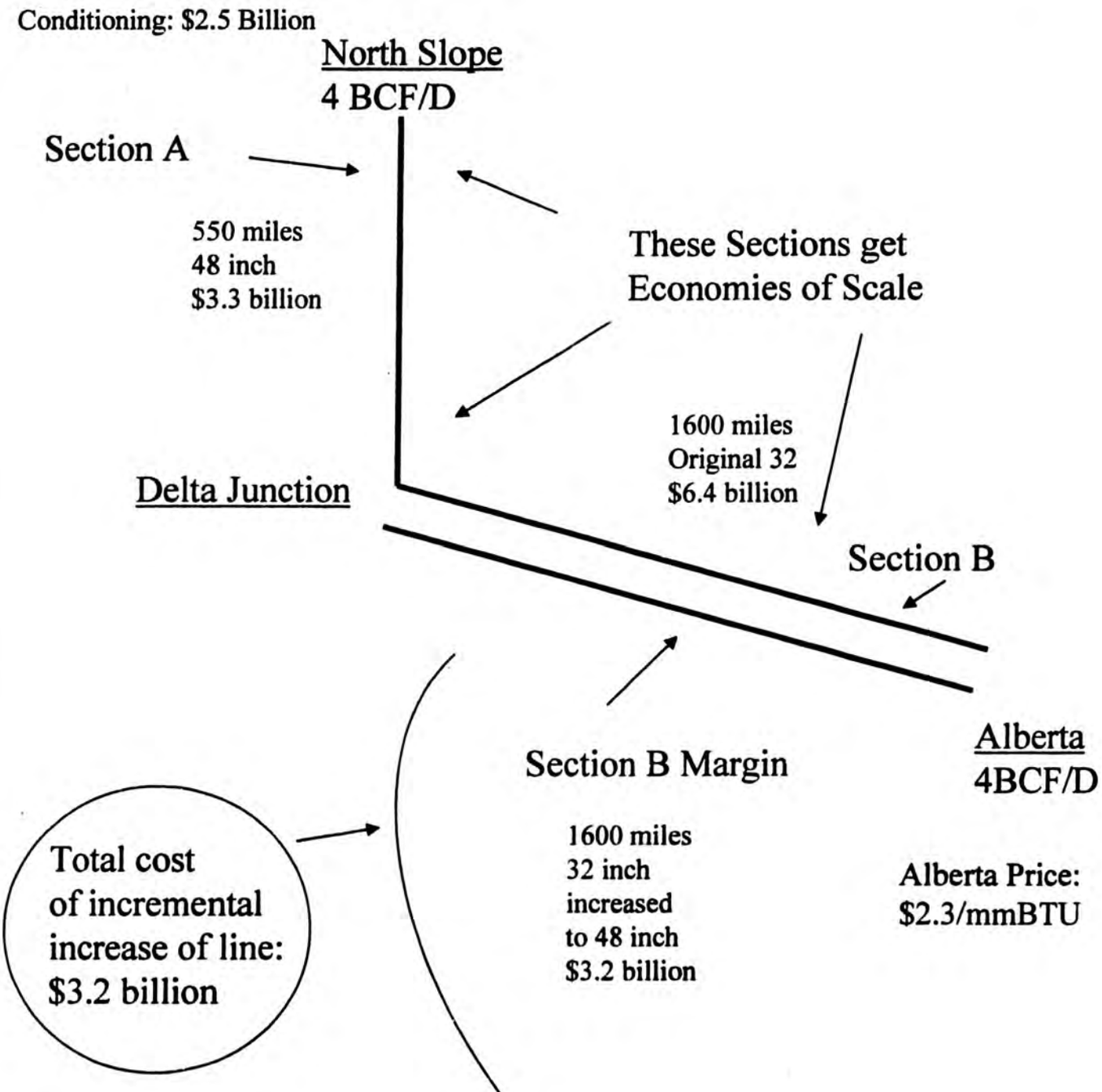
Economies of Scale



Typical Y Line Concept



Typical ALCAN Route



Issue #4
Price of Product

Pacific Rim Market

- Demand in the Pacific Rim --- 20 MTA for next ten years
- Supply potential --- 60 MTA from the Middle East and other countries
- The only way to enter the market is to have low prices
- Cannot use historic prices
- Lower prices reduce ROR

North American Market

- Demand in North America will increase at 2% per year
- Supply in Mid Continent will begin to decline
- LNG imports are hard to get into the US
- One to two new BCF per day of gas will be needed every year
- US prices can shoot up
- North America is the better market

Issue #5
Risk

- Producers must guarantee a "Ship or Pay" contract
- Producers take the risk no matter who owns the pipeline
- Only TAPS and Soviet Pipeline are as large as Alaskan gas line
- It is an all or nothing project
- Therefore, any pipeline project must obtain high rates of return (ROR) to compensate for risk

Issue #6
Federal Tax Exemption

Tax Free Bond Financing

- Tax free bonds can reduce financing costs
- As project finance costs decline, the project ROR can increase
- Possible to get tax free bonds from Railroad bonding or a natural gas authority

Tariff Income Tax Exemption

- Pipeline owners pay a tariff income tax
- An income tax exemption can cut those taxes
- HOWEVER,
  Passing on that benefit to producers will still incur an income tax
- Producers cannot gain with a tariff income tax waiver

Issue #7
In-State Demand

- A pipeline can be built to support in-state demand
- If in-state demand is delayed, then there is unused capacity
- Someone must pay for the added unused capacity of any pipeline project
- If there is unused capacity built, the ROR declines

Producer Numbers

- We asked for but have not yet received producer study numbers for their projects

Approximate Model Cost Assumptions

- Pipeline Costs
  - $140,000 per inch mile (less in Canada) includes pipe and compressor
  - Example: 4 BCF needs 46 inch pipe, 1 mile will cost $6.4 million

- Conditioning Plant Costs
  - $600 million per BCF plus some fixed costs

- Liquefied Natural Gas (LNG) Plant costs
  - $1.6 Billion per BCF

- LNG Tankers
  - $175 million per ship
  - need three ships per BCF

- Gas losses
  -There are some gas losses during gas shipping which reduces revenues

Final Model

- Compared different projects with a similar cost structure
- Used ROR to compare the different projects
- Included the sale of NGL's at sustainable levels

30 Years of Production

	Capital Cost (millions) (2002$)	bcf/day	Return on Equity	Return to Project	Wellhead	State Revenue (millions) (2002$)	Federal Revenue (millions) (2002$)	Canadian Revenue (millions) (2002$)	Undiscounted Profit (millions) (2002$)
Yukon Pacific									
YPC LNG TAGS 1.4									
YPC Numbers 75/25 Dbt/Eqt	$9,500	1.4	N/P	**14.80%**	$0.50/mmBTUs	N/P	N/P	N/A	N/P
YPC model 75/25 Dbt/Eqt	$9,444	1.4	19.83%	**13.21%**	$0.49/mmBTUs	$5,500	$4,610	$0	$10,498
NERA LNG 1.5									
70/30 Dbt/Eqt	$9,210	1.5	18.82%	**13.35%**	$0.48/mmBTUs	$5,984	$5,750	$0	$12,354
100% Equity			12.08%	**12.08%**	$0.01/mmBTUs	$6,568	$11,511	$0	$19,837

INPUTS:

Cost:	YPC	NERA
Total Conditioning Plant	$1,500	$1,687
Total Pipeline	$3,305	$3,397
Total LNG/MT	$3,049	$2,429
LNG Tankers	$1,590	$1,696
Total Other Expense	$0	$0
Total all	$9,444	$9,210

Price:	YPC	NERA
LNG	$3.50/mmBTUs	$3.10/mmBTUs
CA price	$2.75/mmBTUs	$3.10/mmBTUs
AK price	$2.50/mmBTUs	N/A
LPG	$16.70/Bbl	$15.00/Bbl
NGL	$5.53/Bbl	$8.40/Bbl

Sold:	YPC	NERA
LNG	7.0 MTA	8.5 MTA
LPG	75,000 Bbl	57,655 Bbl
NGL AK	50,000 Bbl	60,064 Bbl
NGL ANS	0 Bbl	0 Bbl

N/P: Not Provided
N/A: Not Applicable

30 Years of Production

	Capital Cost (millions) (2002$)	bcf/day	Return on Equity	Return to Project	Wellhead	State Revenue (millions) (2002$)	Federal Revenue (millions) (2002$)	Canadian Revenue (millions) (2002$)	Undiscounted Profit (millions) (2002$)
Alaska Natural Gas Port Authority									
ANGPA Y-Line 6									
ANGPA Numbers 100% Debt	N/A[1]	6.73	N/A	N/A	$0.75/mmBTUs	$9,115 (@ 7.3% NPV)	$0	N/P	N/P
ANGPA model 85/15 Dbt/Eqt	$24,744	6	34.84% [2]	14.58%	$1.14/mmBTUs	$27,932 or $8,993 (@ 7.3% NPV)	$22,549	$2,525	$56,014
NERA Y-LINE 6									
70/30 Dbt/Eqt	$24,051	6	24.51%	15.05%	$0.83/mmBTUs	$23,678	$22,889	$3,843	$49,835
ALCAN Portion		3		15.64%	$0.83/mmBTUs				
LNG Portion		3		14.57%	$0.83/mmBTUs				
ALCAN Marg[3]				17.70%					
ALCAN 6	$16,622	6	29.90%	16.67%	$1.03/mmBTUs	$24,934	$23,512	$5,686	
100% Equity	$24,051	6	14.31%	14.31%	$0.49/mmBTUs	$22,123	$34,923	$7,259	$71,155
ALCAN Portion		3		15.38%	$0.55/mmBTUs				
LNG Portion		3		13.49%	$0.37/mmBTUs				
ALCAN Marg[3]				18.36%					
ALCAN 6	$16,622	6	16.87%	16.87%	$0.78/mmBTUs	$23,072	$29,771	$10,753	

INPUTS:

Cost:	ANGPA	NERA
Total Conditioning Plant	$4,200	$5,144
Alaska Pipeline	$9,706	$6,794
Canadian Pipeline	$3,049	$3,049
Alaska LNG/MT	$4,095	$5,096
Alberta Stripper Plant	$450	$724
LNG Tankers	$3,244	$3,244
Total less ANGPA Omissions[1]	$18,001	$17,034
Total all	$24,744	$24,051

Price:	ANGPA	NERA
LNG	$3.35/mmBTUs	$3.10/mmBTUs
Albt. Price	$2.30/mmBTUs	$2.30/mmBTUs
LPG	$15.00/Bbl	$15.00/Bbl
Propane	N/A	$14.00/Bbl
NGL	N/A	$8.40/Bbl
NGL ANS	$16.50/Bbl	N/A

Sold:	ANGPA	NERA
Gas to Alberta	3 BCF	2.59 BCF
LNG	14.0 MTA	17.93 MTA
LPG/Propane	260,000 Bbl	97,826 Bbl
NGL	0 Bbl	184,395 Bbl
NGL ANS	81,000 Bbl	0 Bbl

1 ANGPA model only includes capital costs incurred in Alaska.
2 Return on equity is skewed by the large debt proportion.
3 The marginal value if all South Shore gas is redirected to Alberta.

30 Years of Production

	Capital Cost (millions) (2002$)	bcf/day	Return on Equity	Return to Project	Wellhead	State Revenue (millions) (2002$)	Federal Revenue (millions) (2002$)	Canadian Revenue (millions) (2002$)	Undiscounted Profit (millions) (2002$)
North Slope Gas Producers									
PRODUCERS ALCAN 4									
Producer's Numbers 100% Equity[1]	$13,200 [2]	4	N/P[3]	N/P[3]	$0.79/mmBTUs [4]	$22,700 [5]	$23,700 [5]	$18,100 [5] (to Chicago)	N/A
Producer model 100% Equity	$11,900	4	15.79%	**15.79%**	$0.63/mmBTUs	$14,032	$18,886	$7,942 (to Alberta)	$44,111
NERA ALCAN 4									
70/30 Dbt/Eqt	$12,881	4	26.44%	**15.63%**	$0.87/mmBTUs	$15,177	$14,256	$4,502	$33,553
100% Equity				15.36%	$0.59/mmBTUs	$13,825	$19,009	$8,507	$45,068

INPUTS:

Cost:	Producer	NERA	Price:	Producer	NERA	Sold:	Producer	NERA
Total Conditioning Plant	$2,600	$3,608	Albt. Price	$2.25/mmBTUs	$2.30/mmBTUs	Gas[6]	4 BCF	3.42 BCF
Pipeline to Alberta	$9,000	$8,308	Propane	$15.00/Bbl	$15.00/Bbl	Propane[6]	45,000 Bbl	79,203 Bbl
NGL Stripper Plant	$300	$965	NGL	N/A	$8.40/Bbl	NGL Albt	0 Bbl	127,513 Bbl
Total all	$11,900	$12,881						

1 From producer's midsummer report.
2 Includes development of Pt. Thomson at a cost of $1.3 billion.
3 According to producer's report.
4 Estimated on gas energy content of 1.08 mmBtu's per mcf.
5 In current dollars, not deflated.
6 Estimated.

4/10/02
JNGP

ALASKA STATE LEGISLATURE

Chairman: Senator John Torgerson
Vice Chair: Senator Gary Wilken
Senator Rick Halford
Senator Ben Stevens
Senator Robin Taylor
Senator Kim Elton
Senator Georgianna Lincoln

Official Business

State Capitol, Room 427
Juneau, AK 99801
Phone: (907) 465-4907
Fax: (907) 465-4779

SENATE RESOURCES COMMITTEE

SPONSOR STATEMENT
SB 360
ALASKA NATURAL GAS PROJECT ACT

Support for the expeditious construction and operation of an Alaska natural gas pipeline project has been one of this legislature's highest priorities. This legislature formed a Joint Committee on Natural Gas Pipelines to work with the federal government with regard to pipeline issues and to take whatever action may be appropriate to ensure that the state's interests are protected. The Joint Committee has worked with the United States Senate on a bill that would expedite construction of an Alaska gas line and would provide certain benefits to the citizens of Alaska. The Joint Committee adopted certain proposals reflecting principles to protect the state's best interests that should govern the development of a pipeline project.

Consistent with those principles, SB 360 seeks to expedite the construction and operation of an Alaska gas line from the North Slope, whether south through Canada to the lower 48 or to Alaska tidewater for shipment as LNG ("Project"). It provides incentives and other benefits to those project sponsors who are willing to work with the State of Alaska to ensure: (1) opportunities for employment of Alaskans and for contracting with Alaskan businesses are maximized; (2) potential in-state demand for gas from the project can be satisfied; and (3) competition in the exploration and development of northern Alaska gas is promoted.

Currently, a project sponsor for a pipeline Right-of-Way (ROW) lease to construct a pipeline from the North Slope can proceed under the provisions of the Alaska Pipeline Right-of-Way Leasing Act. However, those provisions and other provisions of Alaska law will be modified for a sponsor who agrees to do the following:

1. Train and hire Alaskans and use Alaska businesses in the construction and operation of the Project consistent with constitutional provisions.
2. Complete a study on in-state demand and submit a plan that must be approved by the RCA to meet that demand.
3. Complete a study on natural gas resources in northern Alaska and submit a plan that must be approved by the RCA to maximize

access to the Project so that competition in the Alaska oil and gas industry is promoted.

4. Update those demand and resources studies ten years after construction of the Project starts.
5. Agree to provisions in the ROW lease providing for in-state use of gas and expansion of the Project.

A project sponsor can still proceed to get a ROW lease without doing the above, but will not get the benefits described below.

If a project sponsor gets certifications from the appropriate agencies that the sponsor will or has done all of the above, the sponsor gets the following expeditious treatment in obtaining authorizations to construct and operate the Project:

1. The Project may be phased under the ROW leasing act.
2. All agencies must give full cooperation to the DNR commissioner on Project matters by providing information and by issuing any necessary authorizations at the earliest practicable date, on an expedited basis, and with precedence over any like matter pending before the agency.
3. Any authorization may be amended as necessary to further the purposes of the Act.
4. If the governor finds a provision of law that impedes the Project, he may propose a waiver of law.
5. Any decisions by the commissioner and other agencies shall be subject to limited judicial review only and such claims must be brought within 60 days.

In addition, a project sponsor, who gets the required certificates, can be granted certain financial incentives. First, the DOR commissioner may waive, reduce, or defer all or a portion of the property tax payments relating to the Project upon a showing that the Project would not otherwise be economically feasible and an agreement to begin construction by a certain date, and approval by the legislature. Second, the DNR commissioner may waive, reduce, or defer all or a portion of the royalty payments relating to the Project upon a similar showing, agreement and legislative approval. Third, the Alaska Railroad Corporation may provide tax exempt financing for the project. These financial incentives will not be available to a project sponsor who does not get the required certificates.

4/10/02
JNGP

ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

Official Business

Senator John Torgerson, Chair
Senator Rick Halford
Senator Pete Kelly
Senator Johnny Ellis

Representative Joe Green, Vice-Chair
Representative Brian Porter
Representative Scott Ogan
Representative John Davies

MEMORANDUM

TO: Joint Committee on Natural Gas Pipelines Members

FROM: Senator John Torgerson, Chair

DATE: April 10, 2002

RE: Global Petroleum Show – Calgary, Alberta

Senator John Torgerson and the International Alaska Highway Pipeline Committee would like to invite Joint Committee on Natural Gas Pipelines members to join us in participating in the Global Petroleum Show to be held in Calgary, Alberta, Canada June 11-13, 2002.

This is the largest and most comprehensive biennial oil and gas show held anywhere in the world. It covers 500,000 sq. ft. of exhibit space and houses over 1,450 petroleum industry companies. Over 60,000 visitors from 88 countries attended in 2000.

We have secured a 10'x10' exhibition booth for Alaskan companies and the Division of Oil and Gas to display promotional information. We have also reserved the Archie Boyce Theatre, a 240 person theatre at the Centre 21 Exhibition site, for a panel discussion forum on June 12th.

The current outline for the forum is very fluid as we seek input from various agencies and institutions on the state/provincial and federal level. We envision a two-tiered Regulations panel to focus on how to approach working towards an Alaska gas line and potential barriers. The first tier will engage in a discussion between FERC and NEB representatives on the federal level and the second tier will involve state/provincial regulatory agencies.

Session: January – May
State Capitol, #427
Juneau, AK 99801
Phone: 907-465-2828
Fax: 907-465-4779

Interim: May – December
35477 Kenai Spur Hwy., Suite 101A
Soldotna, AK 99669
Phone: 907-260-3041
Fax: 907-260-3044

A Labor panel will consist of the Commissioners and Ministers of Labor discussing labor issues and potential barriers, such as constitutional hiring impediments in Alaska.

A Training panel will include major universities in the region as well as vocational training schools that will discuss workforce development, cross-border training, and reciprocity agreements.

We also hope to have a NAFTA attorney available to speak on cross-border issues that will need to be examined and representatives from First Nations in the northern regions.

We have reserved a block of 25 rooms at the Fairmont Palaser Hotel (a Calgary landmark!) in downtown Calgary at the rate of $199 CDN per night +7% tax from June 9-14, 2002. ROOMS NOT RESERVED BY APRIL 15, 2002 WILL BE RELEASED!!

A detailed website for the Show is maintained at: www.petroleumshow.com
Registration to the attend the show is free at:
http://www.petroleumshow.com/registration/regtype.asp?status=visitor&show=2&id=&comid=&expid=&areatype=featured&othershow=&l2=

Please call Kim Ognisty in Senator Torgerson's office at 465-3421 for more details and participation confirmation.

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2961 SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPLINES, 2001-02

725





INTERNATIONAL ALASKA HIGHWAY PIPELINE COMMITTEE

Senator John Torgerson, Alaska
Minister Scott Kent, Yukon Territory
MLA Mark Hlady, Alberta
Minister Greg Halsey-Brandt

Mission Statement

The mission of the International Alaska Highway Pipeline Committee is to identify and promote measures that the Legislatures of Alaska, Alberta, British Columbia, Northwest Territories, and Yukon may take to expedite the timely delivery of natural gas to market via the Alaska Highway Pipeline Project while maximizing benefits to jurisdictions that are affected.

Principles

1) To encourage a decision to begin construction of an Alaska pipeline projects.
2) To openly exchange information.
3) To maximize local jobs and business opportunities.
4) To ensure community access to the resource.
5) To encourage aboriginal participation in Alaska Highway pipeline projects.
6) To recommend a streamlined regulatory process.
7) To meet jointly with producers and pipeline construction companies to identify barriers and work toward solutions.
8) To complete this committee's work by December 1, 2002 and submit a written report to their respective legislative bodies on their findings and accomplishments, including recommendations or issues still left unresolved or programs that should be continued.

Senator Torgerson
Session: January – May
State Capitol, #427
Juneau, AK 99801
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Fax: 780-422-1671

Accommodation Form - Global Petroleum Show – June 11-13, 2002

INSTRUCTIONS: • Print or type requested data using abbreviations as necessary.
• Complete each part below in detail for correct processing.

FILE: _____

CONFIRMATION WILL BE SENT TO THIS PERSON FROM THE HOTEL:

NAME _____
FIRST LAST

COMPANY _____

ADDRESS _____ CITY _____

PROV. _____ POSTAL CODE _____ PH.# (_____) _____

CREDIT CARD TYPE _____ #: _____ EXP. DATE _____ FAX# (_____) _____

ACCOMMODATION BUREAU POLICY

- Rooms will be assigned on a first-come first-serve basis. **(Hotels sell-out, book early.)**
- Prices quoted are for clients booking through Eu-Anna Hospitality only.
- Hotels will confirm directly. Please check confirmation for advance deposit requirement.

PLEASE RETURN THIS FORM TO:

Eu-Anna Hospitality
282 - 11830 Kingsway Avenue
Edmonton, AB T5G 0X5
PH: (780) 453-3030 • FAX (780) 453-2077
1-888-559-8170

ROOM OCCUPANTS

INSTRUCTIONS:

- Print or type names of all persons occupying each room.
- Select room type desired, with arrival and departure dates.
- Late arrivals require credit card no. or cheque to cover first night accommodation. DO NOT send cheque to Eu-Anna Hospitality. **Hotel will indicate if cheque is required on the confirmation forwarded to you.**
- In all cases other than specified, there will be an additional charge for more than two people or a cot in one room.

Names of All Room Occupants

*** REMEMBER TO PUT IN DATES NEEDED**

Room # 1	1	Single Hotel Room (check one): ❑ 1 Bed ❑ 2 Beds ❑ Smoking ❑ Non-Smoking
	2	
	3	Arr. Date: _____
	4	Dep. Date: _____
		Arrival Time: _____ ❑ AM ❑ PM (check one)
Room # 2	1	Single Hotel Room (check one): ❑ 1 Bed ❑ 2 Beds ❑ Smoking ❑ Non-Smoking
	2	
	3	Arr. Date: _____
	4	Dep. Date: _____
		Arrival Time: _____ ❑ AM ❑ PM (check one)

HOTEL PREFERENCE *(Please print full name of hotel)*

NOTE: You are always given your first choice unless the hotel is totally booked up on that date.

First Choice _____

Second Choice _____ Third Choice _____

Please note: Be sure to list your top three choices.
If these accommodations are sold out at the time your form is received, may we reserve space for you at an alternative Hotel: ❑ YES ❑ NO

- Accommodations have been reserved for the attendees of the show at the following Hotels.
- Also for convenience you can now fax your reservation form direct to **Eu-Anna Hospitality at (780) 453-2077.**
- Please note that room rates do not include the **5% Provincial Room Tax and applicable G.S.T.**

FOR PREFERRED RESERVATIONS FORWARD THE COMPLETED FORM DIRECT TO:

RESERVE EARLY

EU-ANNA HOSPITALITY

282 - 11830 KINGSWAY AVENUE
EDMONTON, ALBERTA T5G 0X5
FAX (780) 453-2077

FAX Reservations Accepted

Hotel listings for Global Petroleum Show 2002

Important note: All bookings should be made by filling out this form.
* means bus transportation is available all day
** means bus transportation is limited to before show and after show.

Downtown Properties (5 to 10 min. drive)

Hyatt Regency * (Host Hotel)	$209
Delta Bow Valley*	$190
Ramada Downtown **	$172-$202
Westin *	$199
Best Western Suites **	$139-179
International Suites *	$175
Sheraton Suites **	$235
Marriott *	$192
Fairmont (The Palliser) *	$199
Holiday Inn Downtown **	$209
Sandman Inn **	T.B.A.

Macleod Trail Properties (5 to 20 min. drive)

Best Western Hospitality Inn **	$129-149
Quality Hotel **	$159-169
Elbow River Inn	$129
Econolodge South	$129 Single - $139 Double
Carriage House **	$159
Travelodge on 92nd **	$89-$99
Comfort Inn and Suites	$149 RM - $179 Suite

Airport Hotels (20-25 minutes by car)

Coast Plaza	$139-169
Radisson	$145
Sheraton Cavalier **	$179
Delta Airport **	$159
Port o Call **	$149
Days Inn Airport	$119

Motel Village

Hampton Inn & Suites	$155
Econolodge Banff Trail	$109 Single
	$119 Double
Econolodge Motel Village	$109 Single
	$119 Double

Other

Four Points Sheraton - Southwest	$139
Glenmore Inn - Southeast Premier Tower **	T.B.A.

IMPORTANT NOTE: **Each hotel may vary on deposit and cancellation policies. Check your confirmation from hotel to confirm these policies. Hotels will fax you confirmations directly.**

Toll Free in North America:
1-888-799-2545 (ext. 561)
E-mail: simonrose@ca.dmgworldmedia.com



Photo credit:

World's Largest Oil and Gas Show

For more than a decade, the biennial National Petroleum Show has been pivotal to international oil and gas suppliers as a venue to launch new products. Held every two years, the Global Petroleum Show will remain as an important showcase for world class technology in the fields of exploration, production and transportation.

This is the largest and most comprehensive oil and gas Show held anywhere in the world. It covers over 500,000 square feet of exhibit space and houses over 1,450 petroleum industry companies. Over 60,000 visitors from 88 countries attended the Show in 2000.

According to independent research an amazing **74%** of attendees indicated they have a purchasing role within their company and over **40%** were proactive in at-show transactions; this represents approximately **$2.8 billion** worth of at-show purchases

CANADIAN INTERNATIONAL PETROLEUM CONFERENCE

Global Petroleum Show 2002 will be held in conjunction with Canada's premier technical conference, the Petroleum Society's Canadian International Petroleum Conference. Contact (403) 237-5112.

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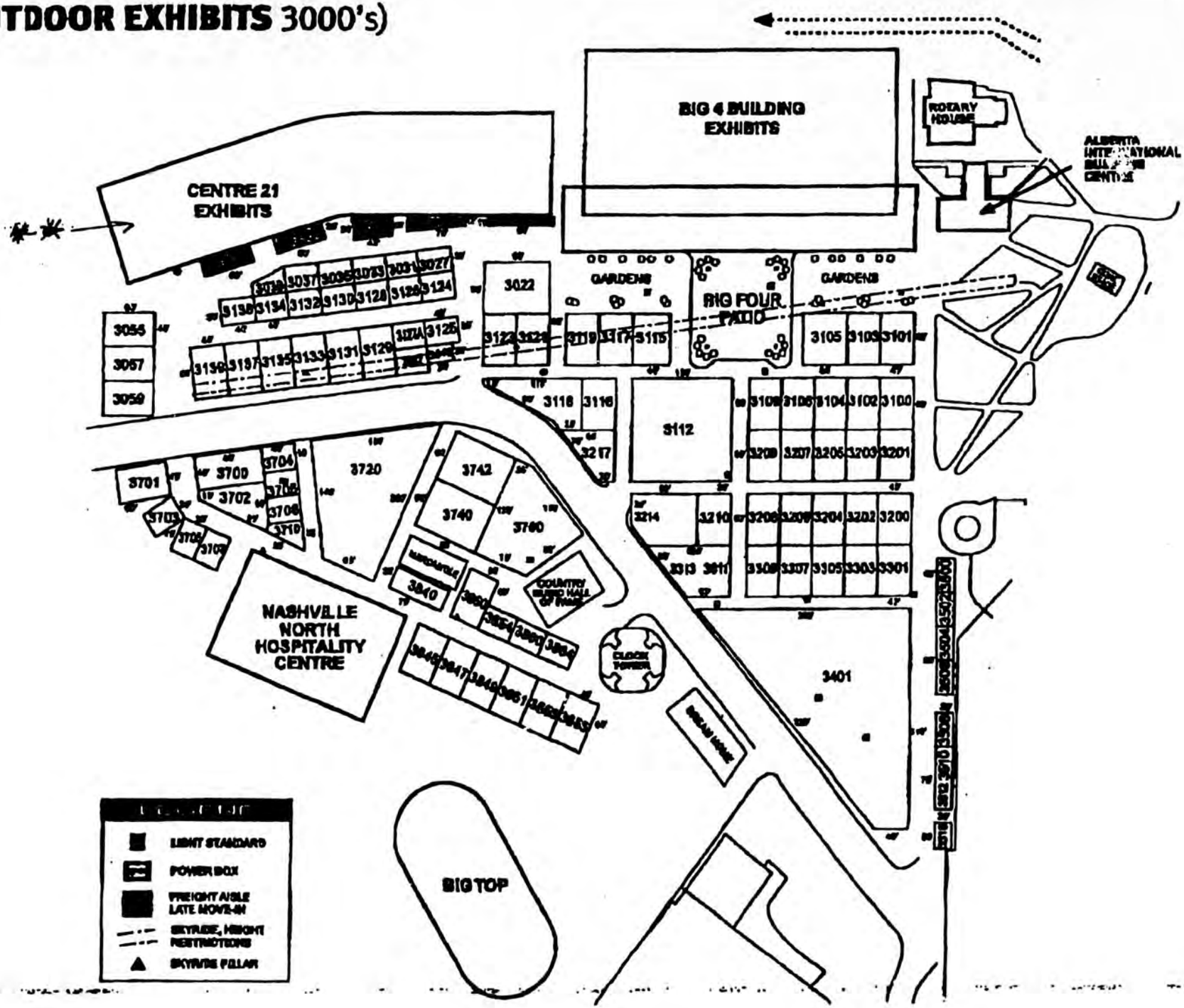
OUTDOOR EXHIBITS 3000's)

location for "North of Sixty" exhibits.



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MONEY

FRIDAY, MARCH 29, 2002

ANCHORAGE DAILY NEWS

Natural gas finds back door in Baja

■ LNG: Mexico is ideal port for firms eager to serve California.

By JOEL MILLMAN
The Wall Street Journal

ENSENADA, Mexico — Some of the world's biggest energy companies are lining up to turn Baja California's rocky Pacific coast into a major receiving port for imported natural gas. Aiming to serve United States consumers without riling United States environmentalists, investors are betting Mexico can be their open back door to energy-challenged California.

Shell Gas & Power, a unit of Royal Dutch/Shell Group, on Wednesday was the latest to announce plans to bring liquefied natural gas to a "regasification" terminal on the Baja California coastline, a $500 million project set to be in operation by 2006.

Already three other consortia have emerged with plans to bring LNG terminals to Baja, just south of the U.S. border. Phillips Petroleum Co. plans a joint venture with Houston's El Paso Corp. to bring LNG to the city of Rosarito from gas fields in the Timor Sea. San Diego-based Sempra Energy and CMS Energy Inc. have plans to bring South American gas to a terminal outside Ensenada. Earlier this month,

GAS: *Mexico is reviewing 18 LNG proposals*

Continued from D-1

Houston's Marathon Oil Co. unveiled a venture with Indonesian state oil company Pertamina to build an LNG complex near Tijuana.

All told, the country is reviewing 18 proposals for LNG terminals, Javier Estrada of Mexico's Energy Regulatory Commission told a natural gas conference in Calgary, Alberta, this month.

LNG projects are ambitious, costing up to $1 billion for all the port facilities, pipelines and regasification plants to convert liquid fuel back into a gas that can be piped to consumers. For Baja, such investment would create the opportunity to diversify employment beyond tourism and the assembly plants that have meant thousands of new jobs in cities like Mexicali and Tijuana.

For the energy companies, LNG offers the chance to "gasify" a new energy market. Mexico imports about 300 million cubic feet of LNG a day, barely enough to meet demand. Bringing cheaper energy to northern Baja California's industrial corridor, where assembly plants pay some of the highest electricity rates in North America, is likely to drive demand for years to come.

Since the mid-1990s, Baja consumers have been allowed to import natural gas piped down from the United States and Canada. The proposed LNG projects will put "Baja at the front of the pipeline, instead of at the back," says Don Felsinger, head of Sempra Energy Global Enterprises. The consortia behind at least three of the announced projects expect to break ground on their plants by late summer, or as soon as Mexican regulators put the finishing touches on a new set of regulations governing gas storage and regasification plants. All four projects are expected to be online between 2005 and 2006.

But in the near term, Mexico may be more promising as a bridge than as a market. The partners in each of the four announced projects say they intend to use Baja to carry natural gas into southern California, where energy demand is surging.

PETROLEUM NEWS ALASKA
March 24, 2002

Alaska, Alberta, or Chicago — who will get North Slope gas liquids?

Some argue the economics favor a 'bullet line' to the expanding Chicago hub; others want extraction in Alaska, Alberta to meet forecast demand in U.S., Asia

By Gary Park
PNA Canadian Correspondent



Courtesy of Williams

Williams' Redwater fractionation plant and natural gas liquids storage facility at Fort Saskatchewan, Alberta, is one of four major NGL hubs in North America. Other companies own plants at the hub as well. It is possible some of Alaska's NGLs will be delivered to this hub.

While uncertainty hangs over the future of an Alaska Highway gas pipeline, a sideline debate is taking place over where ethane and other natural gas liquids from North Slope gas will be extracted.

In one mind, there is no doubt who will make the decision.

The producers — Exxon Mobil Corp., BP PLC and Phillips Petroleum Co. — will have the final say, not the industry, says Norval Horner, vice president of Aux Sable Canada Ltd.

But whether that decision will favor Alaska, Alberta or Chicago is the topic of most speculation.

The prize, assuming North Slope production of

see LIQUIDS page A10

continued from page A1

LIQUIDS

4 billion cubic feet per day, would be 100,000 barrels per day of ethane and similar volumes of propane and butane, he told an Arctic Gas Symposium in Calgary earlier this month.

Horner said he believes Alaska gas will be shipped directly to Chicago, despite Alberta's insistence that no pipeline will cross through the province without giving the local petrochemical industry access to the liquids.

Aux Sable Canada is the subsidiary of a U.S. company that extracts ethane and NGLs at Chicago from the Alliance pipeline, which delivers about 1.5 billion cubic feet per day of gas from northern British Columbia to the U.S. Midwest.

Aux Sable currently produces 40,000 barrels per day of ethane, Horner said it can be easily and inexpensively expanded in line with Alliance's capacity to boost deliveries to 2.1 billion cubic feet per day.

Good economic for bullet

But the Alberta government is still seething over the decision by Canada's National Energy Board to approve Alliance as a "bullet" line crossing through Alberta without allowing any access to the liquids.

Horner suggested that if Alaska gas enters Alberta and gets mixed in with gas in other pipeline systems, it would be "very likely" that some ethane recovery would take place in the province.

But if the ethane "goes to Chicago as a rich stream, it's very likely to be recovered in Chicago," he said.

However, Horner is betting is on a "high pressure, large diameter bullet line" to the emerging Chicago hub, arguing the economics would be "hard to beat."

Other speakers pointed to options involving the recovery of ethane in either Alaska or Alberta.

GAS LIQUIDS CONTINUED

New facilities possible

Mike Hantzsch, vice president of business development at Williams Energy Canada Inc., said his company supports the stripping of ethane before it reaches Chicago and is evaluating the feasibility of a plant in either Alaska or Alberta.

He said such a facility would require feedstock of about 600,000 barrels per day of ethane. Williams already produces 130,000 barrels per day from straddle plants at Cochrane and Empress in Canada.

Under study are new facilities at Fairbanks near Williams' existing oil refinery or at Fort Saskatchewan, the refining district near Edmonton.

Other possible locations in Canada include Empress, which has surplus processing capacity of 10 billion cubic feet per day; James River, Alberta, the certified junction of the Alaska Natural Gas Transportation System; and other sites in northeastern British Columbia.

Hantzsch said preliminary findings by consultants suggest that polyethylene capacity additions in either Alaska or Alberta are supported by forecast demand growth in the U.S. and Asian markets.

He said about 70 percent of polyethylene produced in Alberta would be shipped to Asia with the balance heading for the western United States, while polyethylene from Alberta would be exported equally between the western and eastern United States.

Hantzsch told the conference the cost of building a petrochemical plant in Alberta would be 1.1 to 1.2 times greater that building one in the U.S. Gulf Coast while Alaska's costs would be 1.4 times greater.

He argued Alberta has an edge given it advanced petrochemical industry and its underutilized infrastructure, although challenges include the comparative feedstock cost in Alaska vs. Alberta.

U.S. liquids prices higher

Horner's case for direct shipments to Chicago was based heavily on the overwhelming flow of liquids from Canada and the United States to the U.S. Midwest and east.

In addition he said liquids fetch an average 6 cents per gallon more in the Midwest than Alberta and even more in Mount Bellevue, a storage and petrochemical center on the Gulf Coast.

He said the six pipelines from the Gulf Coast to the Chicago area are underused and Aux Sable is weighing the possibility of reversing one of the lines to carry ethane to the Gulf Coast.

Meanwhile, planning for Mackenzie Delta gas development involves decisions on who will build the pipeline portion shipping dehydrated gas and liquids from Inuvik to Norman Wells, in the central Northwest Territories, and the pipeline to transport liquids from Norman Wells to northwestern Alberta.

Industry observers think it's likely the liquids will be shipped south from Norman Wells to Zama via the Enbridge Inc. system — a 12-inch liquids line that has designed capacity of 50,000 barrels per day, but is currently using only 60 percent of that space.

However, a battle is also looming, with TransCanada PipeLines Ltd. — Enbridge's chief pipeline competitor in Canada — trying to force its Alberta network north to Norman Wells, then requesting that the system be placed under federal jurisdiction that would allow TCPL to boost tolls for unused capacity on its mainline system east of Alberta. ◆

ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

Official Business

Senator John Torgerson, Chair
Senator Rick Halford
Senator Pete Kelly
Senator Johnny Ellis

Representative Joe Green, Vice-Chair
Representative Brian Porter
Representative Scott Ogan
Representative John Davies

MEMORANDUM

To: Members of the Joint Committee on Natural Gas Pipelines

From: Senator John Torgerson, Chair

Date: April 29, 2002

Re: Hogan & Hartson report on Federal Legislative Developments Related to Natural Gas Pipelines

The Senate, by a vote of 88 to 11, approved the comprehensive energy bill (H.R. 4, formally S. 517) on April 25. Before final passage, the Senate substituted language of its own bill (S. 517) for the language approved by the House in H.R. 4 last year and requested a conference with the House to negotiate a single bill that can be sent to the President. Due to controversial differences between the two versions of the legislation, the conference negotiations could prove to be lengthy and difficult.

On Tuesday, April 23, the Senate adopted Amendment # 3257 (as modified) sponsored by Senators Murkowski (R-AK) and Stevens (R-AK), to provide a tax incentive for producers to commit reserves to the proposed Alaska natural gas pipeline. The amendment would provide a federal tax credit if the price of natural gas drops below $3.25 per one million Btu. The credit would stay in place for 15 years after the pipeline is completed. Gas producers would be required to repay the credits when the cost of gas rises above $4.85 per one million Btu. This recapture provision would never expire until all of the credits are paid back. Senate Amendment # 3257 (as modified) is reprinted below.

Session: January – May
State Capitol, #427
Juneau, AK 99801
Phone: 907-465-2828
Fax: 907-465-4779

Interim: May – December
35477 Kenai Spur Hwy., Suite 101A
Soldotna, AK 99669
Phone: 907-260-3041
Fax: 907-260-3044

During the Senate's debate on April 25, an amendment offered by Senator Fitzgerald (R-IL) to strike the provisions authorizing the loan guarantees for the Alaska NG pipeline was adopted by voice vote. However, the adoption of this amendment was later vitiated. Both actions were done as part of en bloc amendments without any discussion or objections on the floor. The net result of these actions is that the loan guarantees are retained in the Senate-passed bill.

The Senate also adopted an amendment striking section 721 from the bill. This section would have prohibited the inclusion of operating pipelines on the National Register of Historic Places without owner consent. The amendment was adopted by voice vote and without debate.

AMENDMENT NO. 3257 TO AMENDMENT NO. 2917, AS MODIFIED

At the appropriate place insert the following

SEC. . CREDIT FOR PRODUCTION OF ALASKA NATURAL GAS.

(a) **IN GENERAL.**--Subpart D of part IV of sub-chapter A of chapter 1 (relating to business related credits), as amended by this Act, is amended by adding at the end the following new section:

``**SEC. 45M. ALASKA NATURAL GAS.**

``(a) **IN GENERAL.**--For purposes of section 38, the Alaska natural gas credit of any taxpayer for any taxable year is the credit amount per 1,000,000 Btu of Alaska natural gas entering any intake or tie-in point which was derived from an area of the state of Alaska lying north of 64 degrees North latitude, which is attributable to the taxpayer and sold by or on behalf of the taxpayer to an unrelated person during such taxable year (within the meaning of section 45).

``(b) **CREDIT AMOUNT.**--For purposes of this section--

``(1) **IN GENERAL.**--The credit amount per 1,000,000 Btu of Alaska natural gal entering any intake or tie-in point which was derived from an area of the state of Alaska lying north of 64 degrees North latitude (determined in United States dollars), is the excess of—

``(A) $3.25, over

``(B) the average monthly price at the AECO C Hub in Alberta, Canada, for Alaska natural gas for the month in which occurs the date of such entering.

``(2) **INFLATION ADJUSTMENT.**--In the case of any taxable year beginning in a calendar year after the first calendar year ending after the date described in subsection (g)(1), the dollar amount contained in paragraph (1)(A) shall be increased to an amount equal to such dollar amount multiplied by the inflation adjustment factor for such calendar year (determined under section 43(b)(3)(B) by substituting `the calendar year ending before the date described in section 45M(g)(1)' for `1990').

``(c) **ALASKA NATURAL GAS.**--For purposes of this section, the term `Alaska natural gas' means natural gas entering any intake or tie-in point which was derived from an area of the state of Alaska lying north of 64 degrees North latitude produced in compliance with the applicable

State of Federal pollution prevention, control, and permit requirements from the area generally known as the North Slope of Alaska (including the continental shelf thereof within the meaning of section 638(1)), determined without regard to the area of the Alaska National Wildlife Refuge (including the continental shelf thereof within the meaning of section 638(1)).

``(d) **RECAPTURE.--**

``(1) **IN GENERAL.**--With respect to each 1,000,000 Btu of Alaska natural gas entering any intake or tie-in point which was derived from an area of the state of Alaska lying north of 64 degrees North latitude after the date which is 3 years after the date described in subsection (g)(1), if the average monthly price described in subsection (b)(1)(B) exceeds 150 percent of the amount described in subsection (b)(1)(A) for the month in which occurs the date of such entering, the taxpayer's tax under this chapter for the taxable year shall be increased by an amount equal to the lesser or—

``(A) such excess, or

``(B) the aggregate decrease in the credits allowed under section 38 for all prior taxable years which would have resulted if the Alaska natural gas credit received by the taxpayer for such years had been zero.

``(2) **SPECIAL RULES.--**

``(A) **TAX BENEFIT RULE.**--The tax for the taxable year shall be increased under paragraph (1) only with respect to credits allowed by reason of this section which were used to reduce tax liability. In the case of credits not so used to reduce tax liability, the carryforwards and carrybacks under section 39 shall be appropriately adjusted.

``(B) **NO CREDITS AGAINST TAX.**--Any increase in tax under this subsection shall not be treated as a tax imposed by this chapter for purposes of determining the amount of any credit under this chapter or for purposes of section 55.

``(e) **APPLICATION OF RULES.**--For purposes of this section, rules similar to the rules of paragraphs (3), (4), and (5) of section 45(d) shall apply.

``(f) **NO DOUBLE BENEFIT.**--The amount of any deduction or other credit allowable under this chapter for any fuel taken into account in computing the amount of the credit determined under subsection (a) shall be reduced by the amount of such credit attributable to such fuel.

``(g) **APPLICATION OF SECTION.**--This section shall apply to Alaska natural gas entering any intake or tie-in point which was derived from an area of the state of Alaska lying north of 64 degrees North latitude for the period—

``(1) beginning with the later of—

``(A) January 1, 2010, or

``(B) the initial date for the interstate transportation of such Alaska natural gas, and

``(2) except with respect to subsection (d), ending with the date which is 15 years after the date described in paragraph (1).''.

(b) **CREDIT TREATED AS BUSINESS CREDIT.**--Section 38(b), as amended by this Act, is amended by striking ``plus'' at the end of paragraph (22), by striking the period at the end of paragraph (23) and inserting ``, plus'', and by adding at the end the following new paragraph: ``(24) the Alaska natural gas credit determined under section 45M(a).''.

(c) **ALLOWING CREDIT AGAINST ENTIRE REGULAR TAX AND MINIMUM TAX.--**

(1) **IN GENERAL.--**Subsection (c) of section 38 (relating to limitation based on amount of tax), as amended by this Act, is amended by redesignating paragraph (5) as paragraph (6) and by inserting after paragraph (4) the following new paragraph:

``(5) **SPECIAL RULES FOR ALASKA NATURAL GAS CREDIT.--**

``(A) **IN GENERAL.**--In the case of the Alaska natural gas credit—

``(i) this section and section 39 shall be applied separately with respect to the credit, and

``(ii) in applying paragraph (1) to the credit—

``(I) the amounts in subparagraphs (A) and (B) thereof shall be treated as being zero, and

``(II) the limitation under paragraph (1) (as modified by subclause (I)) shall be reduced by the credit allowed under subsection (a) for the taxable year (other than the Alaska natural gas credit).

``(B) **ALASKA NATURAL GAS CREDIT.--**For purposes of this subsection, the term `Alaska natural gas credit' means the credit allowable under subsection (a) by reason of section 45M(a).".

(2) **CONFORMING AMENDMENTS.**--Subclause (II) of section 38(c)(2)(A)(ii), as amended by this Act, subclause (II) of section 38(c)(3)(A)(ii), as amended by this Act, and subclause (II) of section 38(c)(4)(A)(ii), as added by this Act, are each amended by inserting ``or the Alaska natural gas credit" after ``producer credit".

(d) **CLERICAL AMENDMENT.--**The table of sections for subpart D of part IV of subchapter A of chapter 1, as amended by this Act, is amended by adding at the end the following new item:
``Sec. 45M. Alaska natural gas.".

Alaska Producer Pipeline Update

April, 2002



ExxonMobil



Outline of Information

- Overview and Conclusions
- Project Design and Technology
- Updated Project Feasibility
- Wrap-up

Outline of Information

- Overview and Conclusions
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- Updated Project Feasibility
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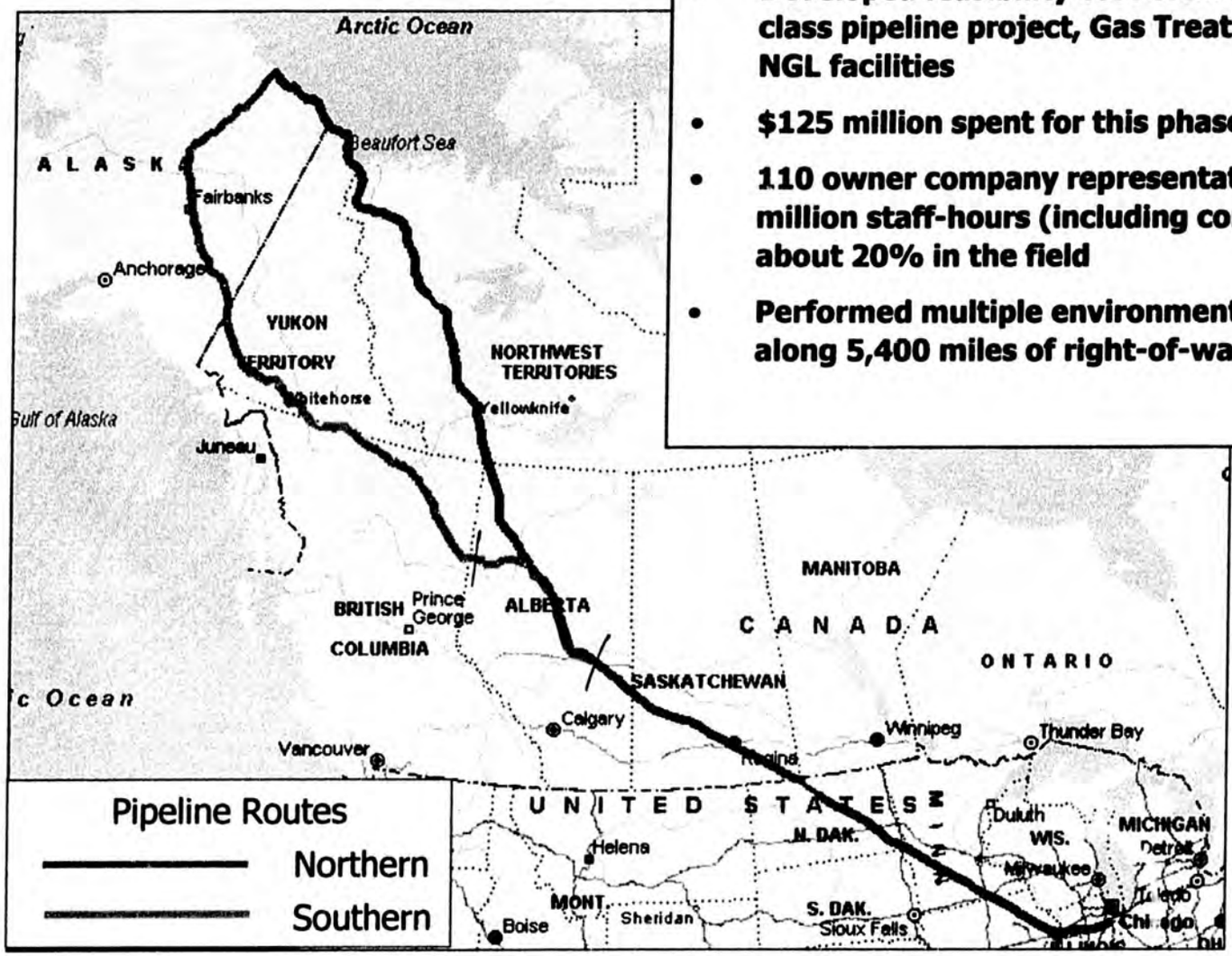
Project Overview

- **Developed feasibility cost estimates for a world class pipeline project, Gas Treatment Plant, & NGL facilities**
- **$125 million spent for this phase of the project**
- **110 owner company representatives and over 1 million staff-hours (including contractors) with about 20% in the field**
- **Performed multiple environmental field studies along 5,400 miles of right-of-way**



bp ExxonMobil Phillips 66

Conclusions

- Project currently not commercially viable
  - Risks outweigh rewards
  - Substantial additional engineering work not justified at this time
  - Future activity must match progress with governments and commercial viability

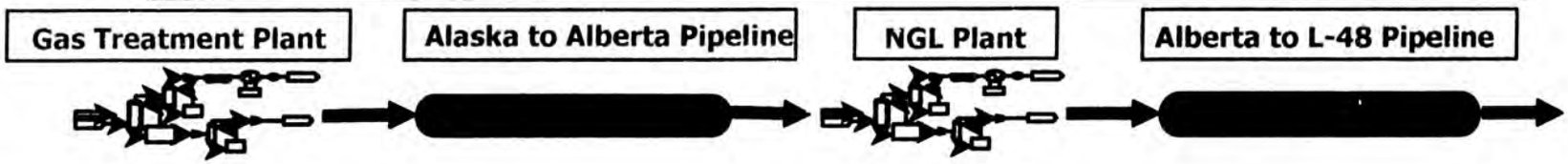
- Governments will play a key role in reducing project cost, schedule risk
  - US Federal regulatory enabling legislation
  - NEB/First Nations regulatory process clarity
  - Alaska fiscal certainty

Outline of Information

- Overview and Conclusions
- **Project Design and Technology**
- Updated Project Feasibility
- Wrap-up

bp ExxonMobil Phillips 66

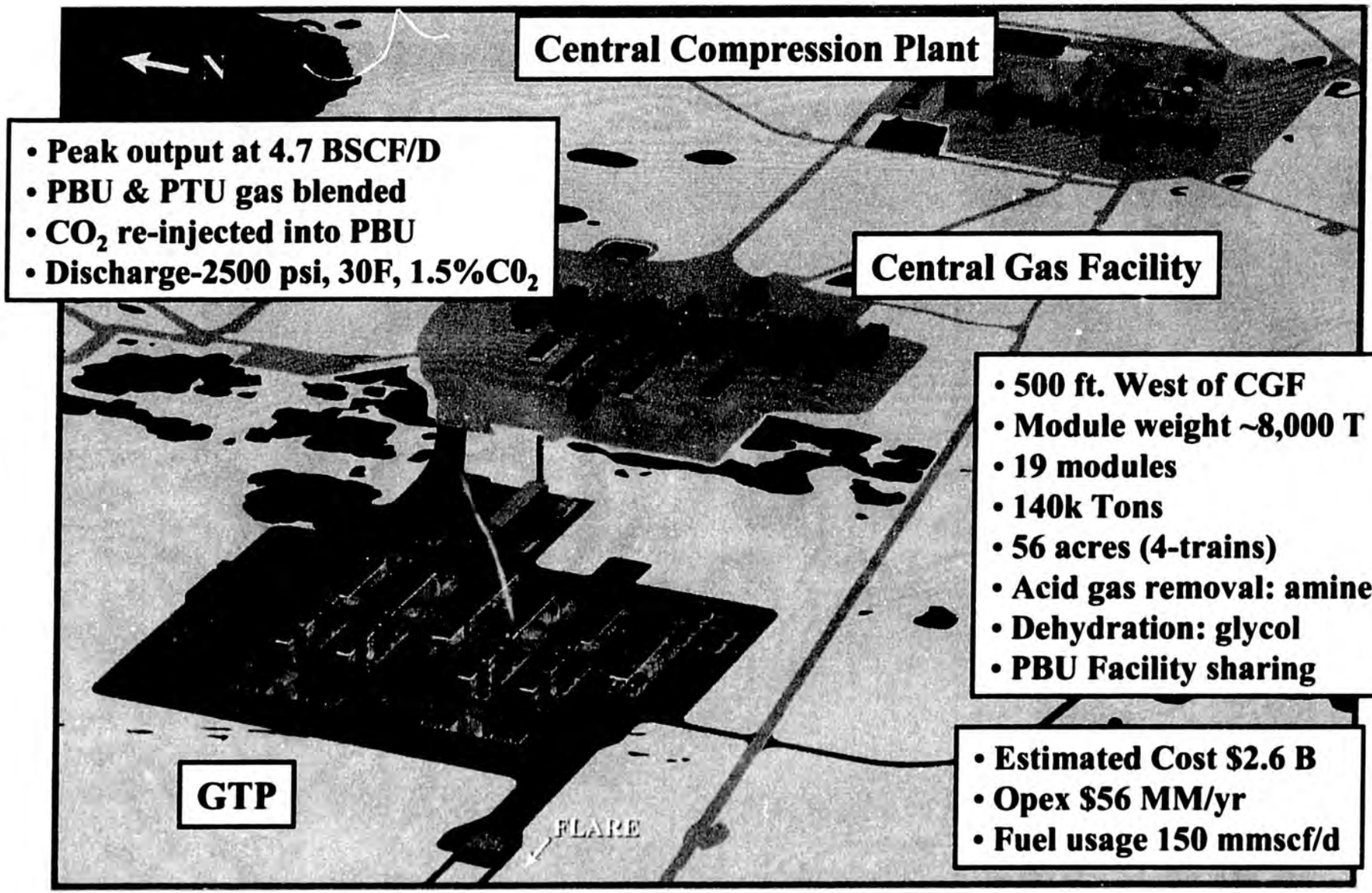
Statistical Summary (Alaska to L-48)



- **Pipeline Design Rate (bcfd) : 4.5**
- **Expansion Potential (bcfd) : 5.6**
- **Compressor Stations : 24 - 28**
- **Total Pipeline Horsepower : 1.2 – 1.4 million**
- **Alaska to Alberta (miles) : 1,800 - 2,100**
- **Alberta to Market (miles) : 1,500**
- **Pipe Diameter (inches) : 52**
- **Operating Pressure (psi) : 2,000 – 2,500**
- **Tons of Steel : 5 – 6 million**
- **Construction Staff-Hours : 50 million+**

bp ExxonMobil Phillips 66

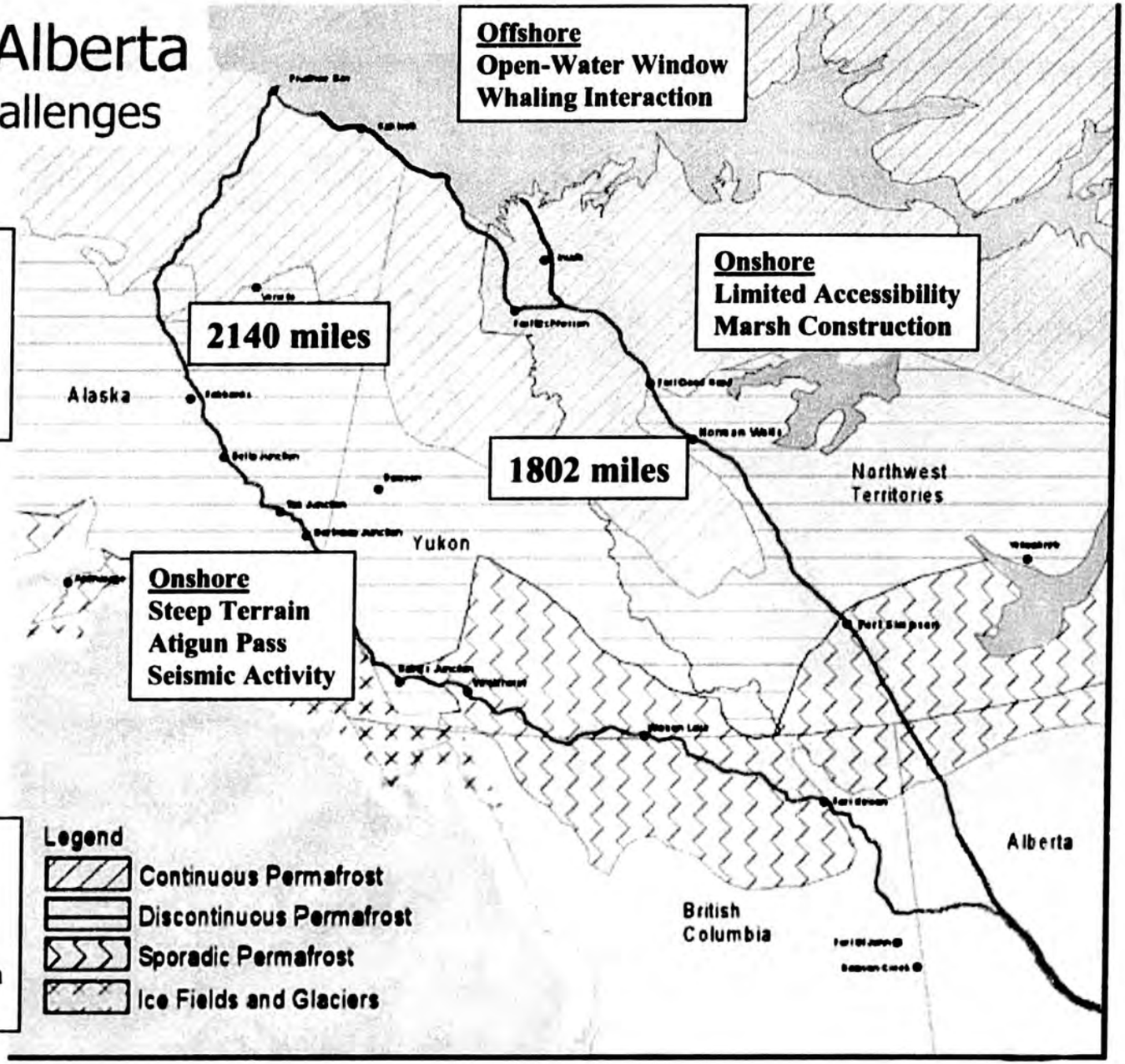
Gas Treatment Plant (GTP)



Alaska to Alberta

Technical Challenges

Common Challenges
Permafrost
River Crossings
Skilled Labor
Pipe Availability
Logistics



Design Basis
52"Pipe
2500 psi
X-80 Carbon Steel
Wall Thickness>1 inch
Buried, Chilled Line

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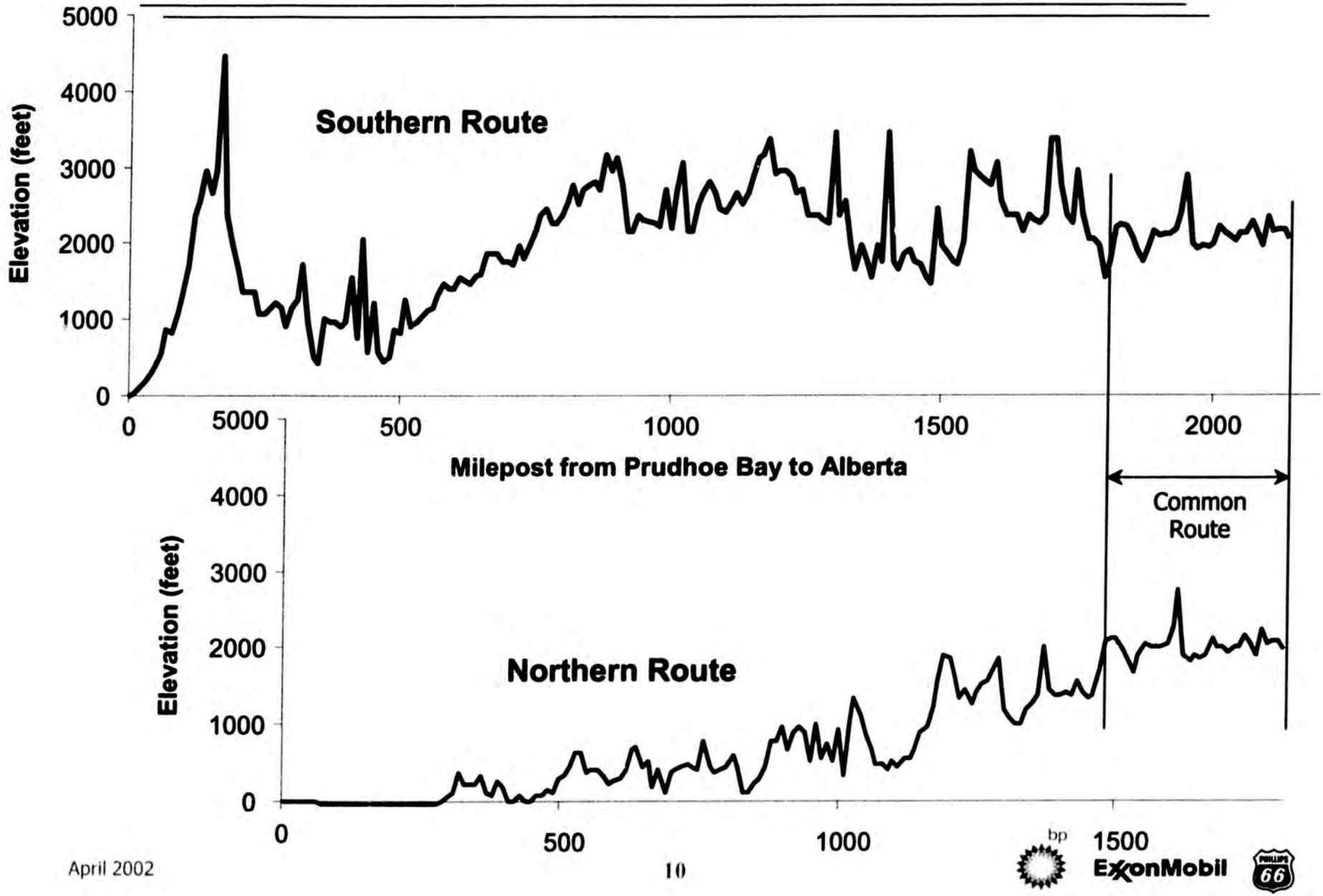
Route Elevation Profiles



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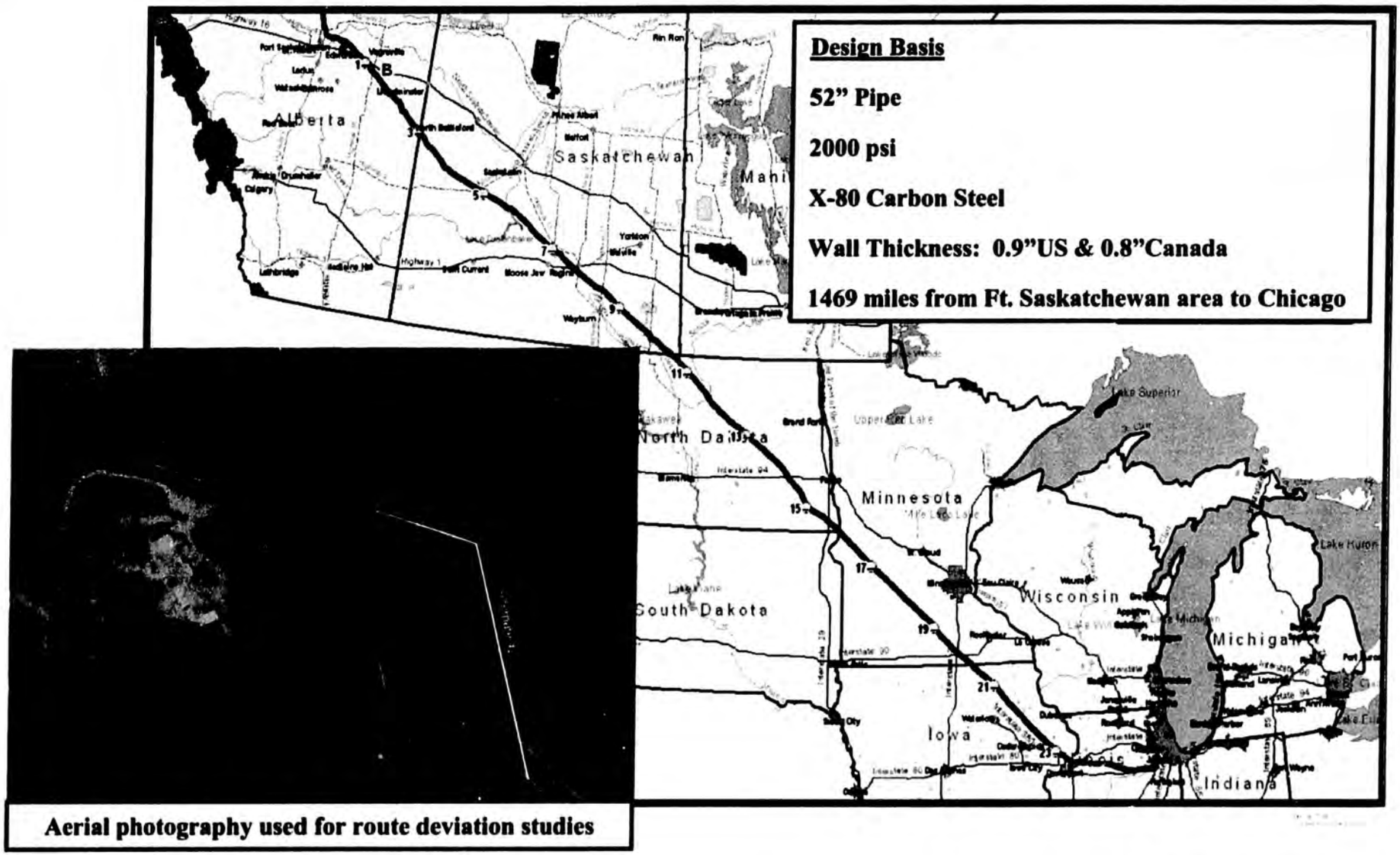
Alberta to Market



Aerial photography used for route deviation studies

bp ExxonMobil Phillips 66

Environmental Field Studies

- Crews of 2 to 5 people mapping / photographing existing conditions
- Helicopters and fixed wing aircraft used for surveys / access
- Field effort exceeded 200,000 staff hours.



- Vegetation & Soils Surveys
- Wildlife, incl Threatened and Endangered Species
- Wetlands, Fisheries, Hydrology & Water Quality
- Cultural & Archaeology Resources
- Marine Mammal Study
- Traditional Knowledge Consultation

Outline of Information

- Overview and Conclusions
- Project Design and Technology
- **Updated Project Feasibility**
- Wrap-up

Updated Project Feasibility

- Joint project feasibility work results in significantly improved project definition
  - Better understanding of risks and opportunities
- Updated study results indicate the following:
  - Higher capital costs
  - Increased volumes delivered
  - Lower operating costs
  - Reduced fuel consumption
  - Current capital cost estimates have accuracy to approximately +/- 20%
  - Achieving lower costs and less cost uncertainty will require substantial future investment
- Project continues to have significant risks:
  - Regulatory/political risks
  - Fiscal risks
  - Cost risk
  - Long-term prices / Market volatility

} Risk predominantly borne by producers, irrespective of pipeline ownership

Capital Costs / Tolls

	Southern Route	Northern Route
Capital Cost ('01, $billion)		
Gas Treatment Plant	2.6	2.6
Alaska to Alberta	11.6	10.8
Alberta to Market	4.6	4.6
NGL Extraction Facilities	0.6	0.6
Alaska Project Share	***19.4***	***18.6***
Mackenzie Delta Share	-	*1.4*
Uncertainty	***+/- 20%***	***+/- 20%***
Sales Gas Rate (bcfd)		
Alaska	4.3	4.3
Mackenzie Delta	-	1.0
Total	4.3	5.3
Project Toll ($/mcf)		
Gas Treatment Plant	0.41 > 1.77	0.41
Alaska to Alberta	1.36	1.28
Alberta to Market	0.62	0.62
Toll to Market	***2.39***	***2.31***
Range	***1.90 - 2.85***	***1.85 - 2.75***

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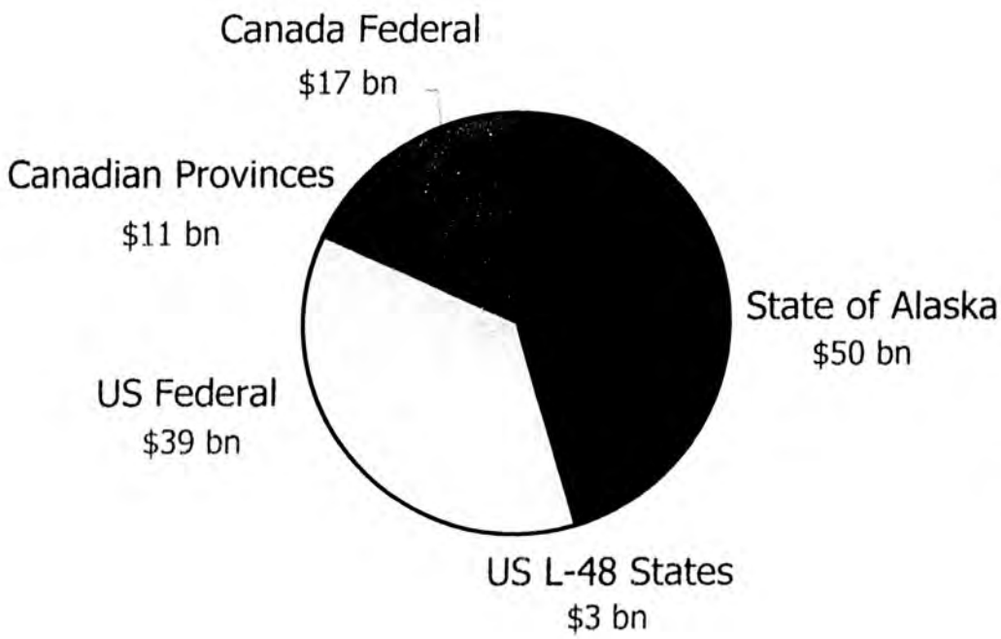
Estimated Government Take

Change 30+ year life

Total Undiscounted Revenue

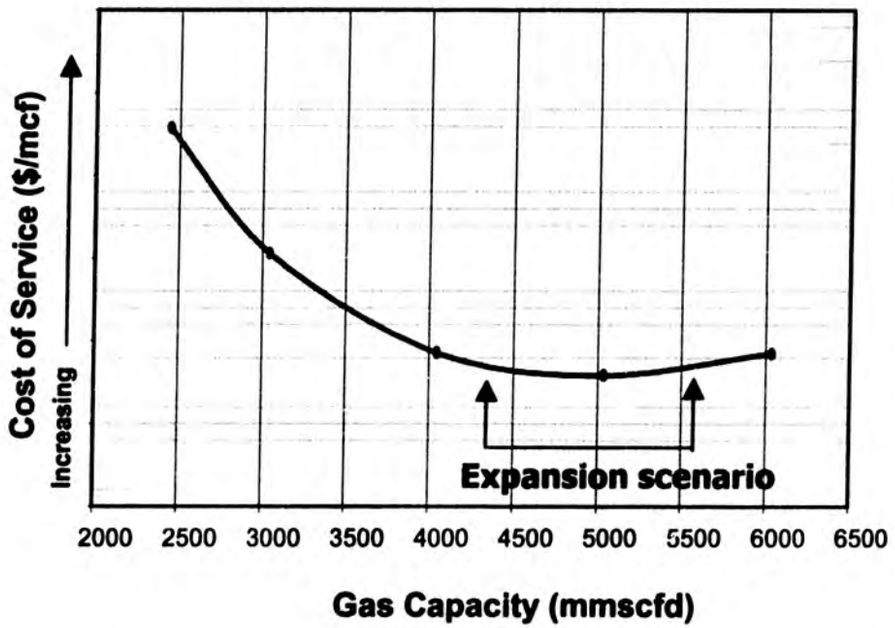
$120 bn



- Revenues are roughly equivalent for Northern and Southern Routes
- Increased government take (vs. Sept. 2001) based on higher system throughput and longer project life
- 51 TCF AK gas reserves produced, including 16 TCF yet-to-be-discovered

Expansion

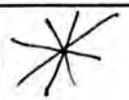
- Expandability built into system design
- System debottlenecking likely to yield small volume improvements
- Approximately 1 bcfd expansion with intermediate compression
- Cost effective expansion facilitated by large diameter pipe
- Expansion will provide access to new gas discoveries



Viable Government Framework is Essential

- Establish predictable regulatory / fiscal regime.
  - Enact US enabling regulatory legislation
  - Progress predictable fiscal framework in Alaska
  - Progress clear and predictable regulatory process in Canada
- These initiatives require support from investors, governments, First Nations, Native communities, shippers, marketers and consumers.
  - Creates best possible structure for successful Alaska pipeline
- Significant forward expenditure will require predictable government framework.
  - Significant investment required to further reduce cost and reduce cost uncertainty
  - Governments will play a key role in reducing project cost, schedule risk
  - Avoid mandates
- Once government framework is established, commercially viable pipeline project still must be identified.

U.S. Enabling Regulatory Legislation



What is it?

- Language currently contained in Senate Energy Bill
  - Amendments may add risk/costs
- Available to any sponsor
  - New legislation will not preclude ANGTS Group from proceeding under ANGTA
  - ANGTS Group or any other investors can also proceed under this legislation
- Creates market-driven, expedited regulatory process for <u>any</u> viable project(s)
  - Subject to FERC regulation; fair and reasonable terms; open access
  - Subject to all environmental laws / regulations; 18-month EIS completion
- Creates Office in executive branch to coordinate all related federal agency activity

<u>Why is it needed?</u>

- Provides for federal regulatory certainty
  - Establishes clear process to encourage competitive, market-driven (lowest cost) solutions
  - Allows any number of producer / pipeline partnerships to evolve
  - Current regulatory risk discourages investment
- Expedites environmental review and project authorization
- Provides timely judicial review to reduce uncertainty

bp ExxonMobil 66

Alaska Fiscal Certainty

What is it?

- Provides for certainty in State government take:
  - Predictable disposition of State royalty gas, consistent with firm transportation commitments
  - Clear, simple, predictable gas valuation for royalty / severance tax payments
  - Severance tax rates and Economic Limit Factor (ELF)
  - Ad valorem tax rates and valuation methodology
  - Corporate income taxes
- Ensures stable fiscal terms over life of pipeline project

Why is it needed?

- Potential for fiscal change creates risk that jeopardizes long payout projects
  - Project already holds significant capital, schedule and market risk
  - Stable fiscal environment encourages long-term investment
  - Avoid future disputes over interpretation

Predictable NEB / First Nations Regulatory Prccess

What is it?

- Establishes clear regulatory processes between NEB and First Nations.
- Detailed plans for cooperation among Canadian Federal, Provincial, Territorial and First Nations regulatory authorities.
- Predictable, expedited process that fully complies with all environmental and regulatory laws.

Why is it needed?

- Ensure timely completion of regulatory and environmental assessment process.
- Lack of clear NEB/First Nations permitting process increases project risk.
- Avoid duplication of environmental assessments and conflict among Canadian governmental agencies and First Nations.

Outline of Information

- Overview and Conclusions
- Project Design and Technology
- Updated Project Feasibility
- Wrap-up

Wrap-up



- **Project currently not commercially viable.**
  - Risk/reward balance
- **Viable government framework is essential.**
  - U.S. enabling regulatory legislation
  - Alaska fiscal certainty
  - Predictable Canadian regulatory process
- **Joint team resources have been redeployed.**
- **Companies will collaborate as appropriate on future work**
  - Trenching trials
  - Input to clear / predictable government framework
  - Cost reduction opportunities

SCOMM

129:12

ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

Official Business

Senator John Torgerson, Chair
Senator Rick Halford
Senator Pete Kelly
Senator Johnny Ellis

Representative Joe Green, Vice-Chair
Representative Brian Porter
Representative Scott Ogan
Representative John Davies

MEMORANDUM

TO: All Senators and Representatives

FROM: Senator John Torgerson
Chair, Senate Resources Committee
Chair, Joint Committee on Natural Gas Pipelines

SUBJECT: Report on the Alaska Natural Gas Pipeline

DATE: May 16, 2002

I am enclosing some information on the Alaska Natural Gas Pipeline that I hope you will find useful. First, there is a report on the natural gas pipeline modeling work done by the legislature's economic experts, Northern Economic Research Associates. In addition, we are enclosing a CD containing the economic models of the different gas line projects built by our experts.

Second, there is a report by our expert on oil and gas matters, Patrick Coughlin. The report provides background information and a status of the provisions in the United States comprehensive energy bill that pertain to an Alaska natural gas pipeline. That bill is currently set to go to a conference committee with U.S. Senate and House members.

Finally, I am enclosing a report on the matters that Mr. Coughlin has been working on for me. He has discussed oil and gas issues with many of you and you should feel free to contact him during the interim if you have technical questions relating to oil and gas.

Session: January – May
State Capitol, #427
Juneau, AK 99801
Phone: 907-465-2828
Fax: 907-465-4779

Interim: May – December
35477 Kenai Spur Hwy., Suite 101A
Soldotna, AK 99669
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REPORT ON THE ALASKA NATURAL GAS PIPELINE

Compiled by Senator John Torgerson
Chair, Joint Committee on Natural Gas Pipelines

Contents

1) Model Report
   a. Model Report CD
2) Background and Status of Federal Legislation
   a. Attachment A: Joint Committee 12 Proposals on Federal Legislation
   b. Attachment B: HJR 44
   c. Attachment C: Alaska Natural Gas Pipeline Act
   d. Attachment D: Articles
3) Patrick Coughlin Work Activity Report

MODEL REPORT

Report for
The Joint Committee on Natural Gas Pipelines
For the Alaska State Legislature

Natural Gas Pipeline Modeling

Submitted by
NORTHERN ECONOMIC RESEARCH ASSOCIATES

Dr. Douglas B. Reynolds
Dr. Robert R. Logan
Dr. H. Charlie Sparks
Mr. Michael Backus

The Joint Committee on Natural Gas Pipelines for the Alaska State Legislature contracted with Northern Economic Research Associates (NERA) to build economic models to determine the feasibility of various Alaska gas projects and to analyze legislative policy surrounding natural gas issues. NERA is an economic research firm made up of experts with experience in oil and energy economics, the Alaska state economy, finance and accounting.

Dr. Reynolds is a professor of oil and energy economics at the University of Alaska Fairbanks (UAF) and has researched oil and energy issues for over fifteen years. He has spent time in Kazakstan, Russia, Norway and Mexico studying their oil and gas industries. Dr. Logan is an economics professor at UAF and has looked at a number of Alaska State economic issues over the last fifteen years including oil and gas lease sale efficiency, mining and military impacts on the local economy, and fishery industry problems. Dr. Sparks is an accounting professor at UAF with finance experience. He was the senior accountant at the Alaska Permanent Fund Corporation where he was responsible for performance evaluations including internal rate of return (IRR) and net present value (NPV) calculations for a diverse portfolio of investments. He has also worked on litigation claims involving lost benefits and on Alaska Housing Finance Corporation studies to determine energy efficiency benefits. Mr. Backus is an Alaskan scholar at UAF and is helping put together the economic models.

NERA has worked with the Joint Committee since January 7th, 2002 and has researched gas pipeline costs, price forecasts and potential gas supplies for an Alaskan gas project. Based on all the data gathered, economic models were developed to show how feasible various natural gas projects were. The following report explains the results of the ALCAN pipeline project.

Introduction

- Part I – Description of An Economic Model (This is the hard part)
- Part II – Alcan Project Model and Key Assumptions (What you need to know about the project)
- Part III – Model Results (How do the results change if the assumptions change)
- Part IV – Conclusion (What you really want to know: the project is economic based on our assumptions)
- Part V – Appendix (CD containing models for LNG 1.5 BCF, Y-Line 6BCF, Alcan Expandable 4.5 BCF, and Alcan Non-Expandable 4.5 BCF for you to play with)

What is an economic model? How is it built?

- An economic model is a simplified representation of a proposed business, project or transaction built on the basis of input assumptions which are combined by a series of mathematical formulas to determine project results and outcome values.

- For an oil and gas company, these input assumptions or estimates would include the production volume, oil or gas price, capital costs, operating costs, taxes, and royalties.

- The input assumptions are based on the best available information from the oil and gas company's geologists, reservoir engineers, economists, facility and pipeline engineers, accountants, and other experts .

- Project cash expenditures and revenues are estimated based on these assumptions.

- Cash flows are put into a spreadsheet or other calculation tool and then a net cash flow is calculated on a yearly basis starting with the initial investment.

- The amount of detail in the model depends upon the complexity and value of the decision facing the company.

What does a model look like?

- Simplified oil and gas cash flow model example

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Revenues						
Volume	0	75	75	50	50	25
Price	0	20	20	20	20	20
T. Revenues	0	1500	1500	1000	1000	500
Costs						
Capital	1000	0	0	0	0	0
Operating	0	550	650	400	500	250
Royalty	0	150	150	100	100	50
Taxes	0	300	300	200	200	100
T. Cost	(1000)	(1000)	(1100)	(700)	(800)	(400)
Net Cash Flow	(1000)	500	400	300	200	100

- Model assumes an initial investment of $1 billion dollars, initial production is large and then decreases with time, the oil price stays constant at $20/bbl, operating expenses vary, royalty is 10% of total revenues, and taxes are 20% of total revenues.
- Model automatically
  - calculates the total revenues by formula that multiplies the volume each year by the price
  - calculates the royalty and taxes by formula that multiplies the total revenues by the assumed royalty and tax rate
  - sums the costs each year to get a yearly total
  - subtracts the total cost each year from total revenues each year to get a yearly net cash flow

- Simplified model has about 50 cells with very simple equations; actual model has about 200,000 cells with many complex, conditional equations

What economic jargon do we need to understand to use an economic model?

- **Time Value of Money Concept** – a $1 today is worth more than a $1 tomorrow

- **Inflation** – The notion that the price of goods and services increases over time
  - Subset of the time value of money concept
  - If we have three percent inflation, a candy bar that cost $1 in 2000, cost about 75 cents in 1990, and about $1.35 in 2010

- **Nominal vs. Real Dollars**
  - **Nominal Dollars** are dollars at the time of the transaction – in our candy bar example, price actually paid was: 75 cents in 1990, $1 in 2000, and $1.35 in 2010
  - **Real Dollars** adjusted, using an inflation index, to a particular point in time – in our candy example, the price paid, adjusted for inflation to a base year of 2000, was: $1 in 1990, $1 in 2000, and $1 in 2010

- **Present Value** – a time value of money concept that brings all investment and return cash flows back to a common date based on a **Discount Rate** or **Hurdle Rate**

- **Discount Rate** or **Hurdle Rate**
  - A rate applied to a series of future cash flows to adjust for risk and the uncertainty of time factor
  - The rate reflects general inflation in the economy
  - The rate reflects that you'd want a higher rate of return on your money if you had to leave it in the bank for five months vs. five years
  - The rate reflects that you'd want a higher rate of return on your money if you invested it in a safe government bond vs. if you invested it in a new company promoting a new product
  - **The Discount Rate or Hurdle Rate is so important we will talk some more about it and how it is calculated.**

How do we calculate the present value of our simplified oil and gas project?

- In our simple oil and gas cash flow example, the yearly undiscounted cash flows were: (1000), 500, 400, 300, 200, and 100. (Refer to earlier slide titled "What does a model look like)
- But, we now know that the early cash flows are worth more to us than the later cash flows because of inflation and our risk tolerance
- Let's discount those cash flows by a discount rate of 0%, 10% and 20% back to the common Year O and see what we get.

Year	NCF@0%	NCF@10%	NCF@20%
0	(1000)	(1000)	(1000)
1	500	455	416
2	400	391	276
3	300	225	172
4	200	137	95
5	100	62	59
Total	500	209	0

- What's our conclusion?
  - If there was no such thing as inflation and the project had absolutely no risk, we'd use 0% discount rate and the project would have a present value of $500 million
  - If the project was very risky, we might use a 20% discount factor and the project wouldn't have any present value to us
  - If the project wasn't very risky, we might use a 10% discount factor and the project would have a present value $209 million

Why is the hurdle rate so important and how is it calculated?

- Why is the hurdle rate so important?
  - The hurdle rate or discount rate (aka cost of capital) reflects the minimum rate of return a firm must make on its investments
  - If the hurdle rate is too high, the firm will reject projects that it should have done
  - If the hurdle rate is too low, the firm could lose money
  - On the same project, different companies can have different hurdle rates depending upon their particular situation

- How is the hurdle rate calculated?
  - It is based on the firm's capital structure, that is the proportion of debt and equity
  - It is also based on its cost of the debt and cost of the equity
  - Example – Say a firm has 40% debt which it borrow at 8% and 60% equity which must be paid at the rate of 15% to attract investors. The cost of debt, however, is after tax so we need to know the company's tax rate, 40%

    Hurdle Rate = debt proportion x [debt rate x (1- tax rate)] + equity proportion x equity rate

    = .4 x [.08 x (1-.04)] + .6 x .15
    = .4 x .048 + .6 x.15
    = 1.92 + 9
    = 10.92% = 11%

- Should the hurdle rate be adjusted to reflect the risk of a particular project?
  - This is a subject of much debate
  - Generally it should not be adjusted unless the risk of the particular project is completely different from the ordinary risks assumed by the company in its business
  - Risk factors can include: project size, country or political risk, or price risk
  - Senate Energy Bill's price risk mechanism greatly reduces any price risk

- What are hurdle rates for oil and gas companies and pipeline companies?
  - For large oil and gas companies over last 20 years, about 10 to 12%
  - For pipeline companies (which usually assume less risk than oil and gas companies) over the last 20 years, about 8 to10%

- What is NERA's opinion about the appropriate hurdle rate?
  - If the federal legislation passes with the price floor, 10 to 12%
  - If it does not pass, 13 to 15%

How do firms and governments use economic models?

- The model calculates various measures of profitability and based on the results company executives decide whether to proceed with the project or not and compare the project to other alternative investment

- The three most common measures are a project's net present value, rate of return, and profitability index
    - Example – Assume our simple oil and gas model and the company's hurdle rate is 10%
    - The net present value (NPV) of the project discounted at 10% is $209 million
    - The rate of the return (ROR) of a project is the discount rate that yields a NPV of zero and in this example is 20%
    - Profitability Index (PI) is the NPV divided by the initial investment. It is considered a measure of the "bang" for the buck and in our example is .21

- In theory, if our hypothetical company's hurdle rate were 10%, it would do this project or any project with a NPV greater than zero using a 10% hurdle rate
    - If it could only do one project and it had another project with a NPV discounted at 10% of $400 million, it would do that project
    - If it could only do one project and it had another project with the same NPV of $209 million, it would do the one with the lowest investment cost employing the PI index criteria

- Firm's also use the model to do "sensitivity analysis"
    - Sensitivity analysis answers what if questions like: How much would our rate of return increase if the price of oil were $25 instead of $20? How much would the rate of return change if our construction costs were 25% higher than expected?
    - It helps the firm determine which input assumption variables are most important and warrant the most attention
    - Our model looks at how different assumptions affect the ROI

- Governments use economic models in much the same way as companies
    - Determine the appropriateness of a fiscal system and its effect on investment in the country
    - Determine the effect of various incentives on private investment and government revenues

How did we build our model?

- Looked at a large number of models
- Reviewed a number of reports and analysis regarding gas markets and pipelines
- Consulted and exchanged data with economists and oil & gas experts from the Department of Revenue and Department of Natural Resources, other governmental experts, and industry and private experts to work out key issues
- Had updates every morning with Senator John Torgerson, Mr. Patrick Coughlin and other experts
- Built several models to examine various route options
- Looked at a number of input assumptions for ALCAN route

Part II
The ALCAN Project Model

- Models project producing gas from the Prudhoe Bay and Point Thomson Units for sale in Alberta
- Includes a conditioning plan on the North Slope, a 2100 mile pipeline to Alberta, and a NGLs extraction plant
- Based on a 4.5 billion cubic feet per day project
- Assumes both gas and NGLs sales
- Uses conservative, reasonable assumptions based on best industry practice
- Terminates in Alberta and assumes other existing lines and smaller new line will transport the gas to the U.S.

What are the key input assumption variables?

- The price of gas and NGLs
- The type of gas, ethane or natural gas liquids (NGLs), available for sale
- The volume of gas that is currently available for sale (gas reserves)
- The volume of gas that may be available for sale (future discoveries)
- Upstream costs
    - Production costs
    - Oil losses
- Project capital costs
    - Conditioning Costs
    - Extraction plant costs
    - Pipeline costs
        - Non-expandable
        - Expandable
        - Terminus
- Operating costs and fuel use
- Pipeline tariff
- Government Revenues (State, Federal, Canada)
    - Property
    - Severance
    - Income
    - Royalties
    - Depreciation
- Incentives
- Project route
    - Alcan, Valdez-LNG, and Y-line
    - Focus on Alcan route

Key Assumptions - Prices and Price Floor

- Forecasts for natural gas prices
  - Natural gas prices are volatile
  - Changes in prices dramatically affect the project's ROI
  - Price forecast is key to project's economic feasibility
- NGLs prices
- Effect of federal legislation
- National security

Key Assumptions
Price Forecast 2010
(Chicago Price 2002$ per MCF)

- Natural gas prices are volatile and future prices are difficult to predict
- Futures say $3.50
- EIA says $2.94 to $3.61
- Producers say $3.12 (EIA mid-price)
- CERA says $2.50 to $3.50
- Federal Legislation uses $3.15 (estimated based on inflation and tariffs)
- Base Model uses $3.15
- Actual May 2002 is $3.70

Key Assumptions – Price
Natural Gas Liquids (NGLs)

- Assume no pentane or higher NGLs sales (already taken by TAPS)
- Assume low use of ethane and propane to extend life of producing oil fields
- Use historic NGLs prices

Key Assumptions - Federal Price Floor

- Federal Legislation contains a price guarantee of $3.25 in Alberta ($2010), about $3.75 in the lower 48
- The $3.25 price is not a subsidy because lower than expected price
- The guarantee reduces price risk by taking away price volatility
- The Legislation includes a tax repayment when prices are greater than $4.88 in Alberta ($2010) or $5.40 in the lower 48
- The federal government calculates a revenue neutral price
- This provision is probably the most important fiscal term affecting the project's economics

Key Assumptions – Price
National Security

- Federal legislation secures national energy security
- The world has become a dangerous place
- Energy is the life blood of the US's and Canada's economy
- Alaska is a safe, secure, and steady source of reasonably priced energy
- Federal legislation is not a subsidy, since revenue neutral, but it does add to US and Canadian national security

Key Assumptions - Proven Reserves

- Prudhoe Bay proven reserves are around 26 trillion cubic feet
- Pt. Thompson proven reserves are 8 trillion cubic feet
- If the pipeline is expandable, expectations are that these estimates are low or that there will be additional discoveries

Key Assumptions - Upstream Costs

- **Gas Production Costs**
  - The Alaska gas pipeline is an incremental project added on to existing oil infrastructure
  - Oil wells already produce gas
  - No upstream costs are included at the Prudhoe Bay Unit because there will be little or no costs to add on this project
  - No upstream costs are included at Point Thompson because a gas project will improve overall field development feasibility

- **Oil Losses**
  - If gas is produced within the next few years, some oil production may be lost
  - Oil losses are expected to be between 0 - 600 mmbo
  - The model assumes an oil loss of 480 mmbo
  - Losses occur late in the life of the project
  - No oil losses could occur because of technology and mitigation methods

Key Assumptions – Downstream Costs: Conditioning Plant, Pipeline & Extraction Plant

- **Conditioning plant** costs about $2.6 billion
- **Pipeline**
  - Typical pipeline Costs
    - Alaska $140,000 per inch mile
    - Lower 48 $60,000/inch mile
    - International $60,000 ± 25,000 (± 25,000 is one standard deviation)
  - Alaska costs are high due to permafrost, high BTU pipelines, large diameter
  - Model assumes that the pipeline terminates around Edmonton, Alberta
    - Edmonton is a natural gas hub and near many NGLs extraction plants
    - Pipeline could terminate in Gordondale about 400 miles short of Edmonton and have a $1.5 billion difference in cost
    - Ending the pipeline in Gordondale implies an extra tariff to get to Edmonton
    - Ending the pipeline in either Gordondale or Edmonton implies an extra tariff to get to Chicago
    - Many experts believe that by 2010 there will be spare capacity in the Canadian pipeline system to transport gas to the lower 48
  - Most projects are built to be expandable depending on existing reserves
    - A low cost Alcan project can be built without expandability and this option is modeled with lower capital costs
    - Expandability is only added if there is an expectation that it will be used
    - The expected project return for the expandable case is shown because the model is run assuming no expansion occurs
    - Total cost given by producers for an expandable pipeline: $14.8 billion ± 20% to Alberta
- **Extraction plant** costs about $0.6 billion

Key Assumptions - Fuel Use and Operating Expenses

- Best practice operating expenses (yearly operating expenses are based on percent of total capital expenditure)
  - 2.2% of pipeline capital
  - 5.4% of conditioning capital
  - 4% of NGLs capital
- Natural gas used to run pumps creates fuel loss
  - Industry best practice has 2% loss of gas per 1,000 miles
  - Conditioning plants loss 4%
  - NGL separation loss 3%

Key Assumptions – Tariff & Depreciation

- A high tariff reduces wellhead value and wellhead revenues
- A low tariff increases royalties and severance taxes
- If the producers own the pipeline, they will prefer a high tariff because it increases their ROI by reducing state revenues
- Model assumes that Producer revenue is generated from wellhead and pipeline
- Tariff setting and taxing is variable due to the depreciation method used and it affects the ROI
  - Base case uses current depreciation schedules without accelerated depreciation
  - Base case uses current taxes in United States and Canada without assuming any changes to those laws

Incentives

- Incentives can increase ROI to make a project more attractive
- Incentives cost government revenues
- Incentives in the form of government subsidies can reduce a company's use of innovation to make the project economic
- Incentives in the form of government subsidies may only accelerate a project that would otherwise be done later
- Assuming state decisionmakers believe that incentives are appropriate, they should be structured to provide the greatest increase to ROI at the least cost to state revenues
- Incentives can be negotiated to benefit both the project sponsors and the state
- "Fiscal terms should not be more attractive [to the project sponsors] than what is necessary to achieve the desired economic activity." Dr. Pedro Van Meurs, Fiscal Systems expert
- The model can show the effect on gas objectives of using different incentives

Part III
Model Results

- Base Case Model – Expandable Pipeline
- With Alaska Property Tax Holiday
- With Capital Cost Changes
- With Price Changes
- With Accelerated Depreciation
- With Tax-Exempt Financing
- Alternative Model – Non-Expandable Pipeline

MODEL RESULTS

Best Guess Model based on Available Information
Project from Alaska North Slope to AECO Hub

Assuming 30 Years of Production	Return on Investment	Wellhead ($/mmBTU)	State Revenue (millions) (2002$)	Federal Revenue (millions) (2002$)	Canadian Revenue (millions) (2002$)	Producer Net Rev. (millions) (2002$)
Expandable Reference Scenario[1]	**15.05%**	**$1.33**	**$23,565**	**$22,662**	**$7,388**	**$48,325**
w/ 4 yr AK tax break[2]	15.22%	$1.35	$23,331	$22,744	$7,388	$48,477
w/ addition 3 yr break	15.36%	$1.36	$23,059	$22,839	$7,388	$48,654
w/ 20% cost overrun	13.03%	$1.12	$20,831	$20,604	$8,863	$45,745
w/ 20% cost reduction	17.80%	$1.54	$26,299	$24,723	$5,910	$50,905
w/ accelerated depreciation	15.32%	$1.35	$23,765	$22,433	$7,386	$48,357
w/ 20% increase in Chicago Price[8]	17.40%	$1.82	$31,949	$30,384	$7,386	$62,662
w/ 20% decrease in Chicago Price[8]	12.40%	$0.84	$15,184	$14,943	$7,386	$33,987
Debt Reference Scenario[3]	14.70% [7]	$1.32	$22,128	$18,471	$4,968	$41,204
w/ Railroad Bonds[3]	15.00% [7]	$1.41	$23,734	$20,038	$4,957	$43,787
Non-Expandable Scenario[4]	16.45%	$1.45	$25,063	$23,795	$6,432	$49,595

Cost:		Price:		Sold:	
Conditioning Plant	$2.6 bn	Albt. Price[5]	$2.60/mmBTUs	In Alberta[6]	4.21 BCF
Non-Expandable Pipeline to Alberta	$10 bn				
Expandable Pipeline to Alberta	$11.6 bn				
NGL Stripper Plant	$0.6 bn				
Non-Expandable Total	$13.2 bn				
Expandable Total	$14.8 bn				

1 *Expandable Reference Scenario* assumes federal tax credit/price floor & non-expansion of pipeline (4.5 bcf/day throughput--a worst case scenario).
2 Property tax break during assumed 4 year construction period.
3 Calculated assuming 70% debt. Used only to evaluate value of Railroad Bonds. Not comparable to other scenarios.
4 Assumes 4.5 bcf/day pipeline is non-expandable, is fully utilized, and costs 6% less on a $/inch-mile basis. A ball park figure for actual profitability as the producers must believe the actual return is above this amount, otherwise they would not opt for expandability.
5 Federal price floor based on EIA forecast in 2002 dollars.
6 Includes small quantities of ethane and propane.
7 Simple weighted average of the return on equity and the taxable bond rate.
8 Represents 63¢ change in the Alberta Price.

Part IV
Conclusion

- Expandable Scenario has 15% return
- If the project is expanded, the return will be higher
- With cost overrun, ROI drops to 13%
- With cost underrun, ROI jumps to 17.8%
- Return includes a price floor
- Therefore there is almost no risk on the venture
- All cases, including cost overrun, exceed the hurdle rate
- This project is economic and should be a go

Conclusion - The Project is Economic

- The Joint Pipeline Committee's model shows that the project is economic at a discount rate of 15%
- A model prepared by Informetrica Limited, a Canadian consulting company, shows that the project is economic at a discount rate of 15% and "[i] n fact, the after-tax internal rate of return for the producers is 31 per cent." Informetrica, Cost-Benefit Analysis of the Alaska Natural Gas Transmission System (January 2002)
- If the federal price floor in the current Senate Energy Bill becomes law, the price floor for gas shipped on the line will be $3.25 Alberta or $3.75 US and others, including the producers have said that the pipeline would be economic at that price:
    - "A commercial project exists today. One with a rate of return of over 12 percent." Ken Thompson, former Arco president and oil and gas consultant, (PNA 3.17.02)
    - Exxon "would have to see a natural gas price of US$3 to US$3.50 per thousand cubic feet on a long-term basis for the pipeline to move ahead." Bob Davis, Exxon spokesman, National Post (May 9, 2002)
    - "On average, the price in [Alberta] would need to be maintained at prices above $3 ...(or $3.50 ...in the United States) for construction [of the Alaska gas pipeline] to commence." Energy Information Administration (EIA), Annual Energy Outlook 2002 (December 20010
    - "Based on the estimated cost of gas at the well, capital costs, operating costs required rates of return, Alaska gas delivered by the proposed pipeline is estimated to competitive when lower 48 wellhead prices are sustained at $3.15 per thousand cubic feet [and] the trigger price with the [Producer's enabling legislation without the price floor provisions] is assumed to be $3.05." EIA, The Effects of the Alaska Oil and Natural Gas Provisions of H.R. 4 and S.1766 on U.S. Energy Markets (February 2002)
- Since the federal price floor has surfaced, the producers have refused to release their project economics and more importantly they have refused to release any information supporting the assumptions in their model

MODEL REPORT

CD

BACKGROUND AND STATUS OF FEDERAL LEGISLATION

MEMORANDUM

TO: Senator John Torgerson
Chairman, Joint Committee on Natural Gas Pipelines
Members of the Joint Committee on Natural Gas Pipelines
FROM: Patrick Coughlin PJC
SUBJECT: Background and Status of Federal Legislation
DATE: May 14, 2002

BRIEF HISTORY
1977 to Summer of 2001

In 1976, the United States Congress passed the Alaska Natural Gas Transportation Act of 1976 (ANGTA). That act authorized the President of the United States to select from competing proposals, a route to transport Alaska North Slope (ANS) gas to lower 48 gas markets and enter into agreement with Canada with respect to the selected route. The President selected a route basically following the Alaska Highway through Yukon through Alberta to the Midwest (Alcan route). The President also selected a consortium of pipelines to build the route. Today that consortium is composed of several companies that are referred to as "Foothills" or the "Pipelines." The president's decision was approved by Congress and became part of an agreement and treaty with Canada.

For purposes of understanding the new proposed so-called "enabling legislation," ANGTA granted the State of Alaska "special rights to serve in-state needs with its royalty gas." (Letter from the law firm of Morrison & Foerster to Senator Torgerson dated August 14, 2001.) The president's decision repeatedly recognized the importance of the state's ability to use its royalty gas for in-state energy and to develop the state's economy. The decision said that an Alcan pipeline could "supply the energy base required for long-term economic development" within Alaska and it could supply natural gas to communities within Alaska along the route as well as other Alaska communities through local distribution lines. Furthermore, to preserve competition and avoid anti-trust concerns, the owners of the vast majority of gas reserves on the ANS, Exxon, BP, and Phillips, formerly Arco (Producers), were prohibited from owning an interest in the Alaska pipeline.[1]

Foothills did a lot of work in the late 1970s and early 1980s to complete the project. However, gas market conditions in the lower 48 dramatically changed and the Alaska pipeline was never built. Throughout the years, Foothills maintained its various authorizations although more are necessary before it could actually begin construction.

In the winter of 2000-01, gas prices in the lower 48 increased dramatically from a historical average of $2.00 to $2.50 per mcf to more than $10.00 per mcf. Many economists and gas industry experts predicted a fundamental shift in supply/demand

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[1] Ultimately, President Reagan issued a "waiver of law" that allowed the Producers to own a minority interest in the pipeline. However, in issuing that waiver, the president specified that there would have to be a thorough antitrust investigation before this ownership could be approved.

market for natural gas. Demand was soaring, primarily driven by new gas fired power generation plants. Supply was in question with many experts wondering whether traditional sources of natural gas like the U.S. Heartland, the Gulf of Mexico Basin, and the Western Canadian Sedimentary Basin, could keep up with the skyrocketing demand.

The Energy Information Agency (EIA), the federal agency charged with studying energy markets, predicted that gas demand in the United States would rise from 23 tcf per year in 2000 to 35 tcf in 2020 and Canadian demand would also grow. Other experts agreed and some predicted greater demand growth. Because of questions concerning the ability of supply sources to meet this demand, the EIA predicted that gas prices would grow at the rate of 2% per year over the next 20 years. The EIA said: "[T]he price is expected to be higher due to less optimistic assessment of natural gas reserves discovered by exploratory drilling." EIA, Annual Energy Outlook 2002 (December 2001). Based on this type of information, oil and gas companies again became interested in gas resources located in so-called "frontier areas" like Alaska.

In May of 2001, President Bush's National Energy Policy Development Group submitted its report on a National Energy Policy. The report recognized that as a result of the rise in gas prices, interest in building an Alaska gas line had been renewed. The report stated:

> America needs the energy that Alaska's North Slope natural gas can provide. The Administration seeks to expedite the construction of a pipeline to deliver this natural gas to the lower 48 states.

The report recommended that the applicable federal agencies and interested parties work closely "to expedite construction of a pipeline to deliver natural gas to the lower 48 states." The report also stated that this "should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required." An Alaska natural gas pipeline was just one part of the national energy policy.

PRODUCERS' ENABLING LEGISLATION
Summer of 2001 to December 2001

Because of the changes in the North America gas market, the Producers interest in developing their ANS gas reserves was renewed. However, the Producers wanted to pursue their own project independent of the Pipelines and did not want to be constrained to the Alcan route. In summer of 2001, the Producers began circulating their enabling legislation. They asserted that passage of this legislation would mitigate regulatory uncertainty and risk and that an Alaska project could not go forward without this legislation. They viewed the legislation as providing a new market driven, expedited regulatory process alternative to the process laid out in the Alaska Natural Gas Transportation Act of 1976 ("ANGTA"). In many respects, their proposed legislation mirrored ANGTA provisions regarding expedited agency review, creation of a federal inspector, and limited judicial review.

The enabling legislation would allow the Producers to build their own Alaska pipeline and to build the 'Over-the-Top" route, which would be a pipeline north from Prudhoe Bay, crossing the Beaufort Sea, through the Northwest Territory and Canada, to the lower 48. The Producers want to have the option to build the Over-the Top route despite the fact that the Alaska Legislature passed SB 164 banning that route in early 2001. The Enabling Legislation did not provide the state with any rights to access gas for in-state use, much less special rights.

Needless to say, the Pipelines were not pleased. The Pipelines, which had rights under ANGTA to construct an Alaska pipeline, asserted that the Enabling Legislation created conflicts with ANGTA. They opposed that legislation. Furthermore, it worried several oil and gas companies like Anadarko and Alberta Energy (Explorers) who had recently come to Alaska with hopes of exploring and producing natural gas. In recent state leases, the Explorers have acquired the rights to a large amount of state acreage with gas potential. The Explorers and the Pipelines expressed concern about placing so much market power in the hands of the Producers, thus, allowing them to control when and how a pipeline is built.

The Alaska Legislature created the Joint Committee on Natural Gas Pipelines (Joint Committee) to deal with issues surrounding ANS gas development. Because a hearing was scheduled to occur in the U.S. Senate in October to deal with the Enabling Legislation, the Joint Committee held a hearing to determine what proposals the Alaska Legislature should make to the U.S. Senate. At its meeting on September 19, the Joint Committee approved a number of proposals that included:

- Prohibit an Over-the-Top route
- Assure that Alaska has fair and reasonable access to gas produced within the state and that the Regulatory Commission of Alaska be involved determining whether that access should be granted and what the appropriate tariff should be
- Assure that Explorers who do not have an ownership interest in the pipeline have fair and reasonable access to space on the pipeline and the ability to obtain expansion capacity of the pipeline
- Create a mechanism for fair and transparent tariffs
- Approve a project labor agreement
- Create provisions for Alaska hire and the use of Alaska businesses
- Prohibit tax incentives for foreign LNG delivered to U.S. markets
- Provide an accelerated depreciation schedule for gas pipelines

Attachment "A." In an October 2nd hearing before the Senate Energy and Natural Resource Committee, Senator Torgerson, chairman of the Joint Committee, presented the committee's proposals. The Senate committee also heard from the governor, representatives of affected federal agencies, representatives of the Producers, representatives of the Pipelines, representatives of the Explorers, environmental groups, and other interested companies and citizens. Following the hearing, the Senate committee continued working on the comprehensive energy bill.

In the meantime, H.R. 4, the U.S. House of Representatives version of an Energy bill, passed that body. It contained a provision banning the Over-the-Top route. This provision was vigorously opposed by the Producers. The Producers also opposed provisions relating to in-state use of gas, access for Explorers and expansion of the pipeline.

In December of 2001, Senator Daschle, the majority leader, pulled the comprehensive energy bill from the Senate Energy and Natural Resources Committee and introduced the Senate version of the Energy bill. It contained a subtitle cited as the "Alaska Natural Gas Pipeline Act of 2002." Although it stated that one of its purposes was "to ensure access to [the Alaska pipeline] on an equal and nondiscriminatory basis and to promote competition in the exploration, development and production of Alaska Natural Gas," it contained little of substance on the subject. Moreover, it did not contain any provisions relating to in-state use of gas or Alaska hire. It did contain a provision stating that it was the "sense of the Senate" that it "urges the sponsors ... to make every effort to use steel that is manufacture or produced in North America and to negotiate a project labor agreement to expedite construction of the pipeline.

SENATE ENERGY DEBATE
January to April 2002

In January of 2002, Senator Murkowski invited Senator Torgerson and other interested parties to meet in D.C. to discuss Alaska gas line issues. The meeting occurred in February and at the meeting the pipeline companies announced that they were no longer opposing the producers' enabling legislation.

In light of the pipeline companies non-opposition to the producers' enabling legislation, Senator Torgerson discussed how to best advocate the Joint Committee's position before the U.S. Senate during this Committee's meeting on February 15. At that meeting this Committee voted to request that the House Special Committee on Oil and Gas introduce HJR 44. This resolution provided that the legislature would support the Producers' Enabling Legislation or the Act so long as it contained:

1. "a provision similar to that in H.R. 4 banning the over-the-top route;"
2. "provisions for Alaskans and Alaska businesses that ensure they have access to the pipeline for in-state consumption and value-added manufacture on a fair and reasonable basis and that the Regulatory Commission of Alaska play a role in determining that access;"
3. "provisions for access to the pipeline by Explorers on a fair and reasonable basis, including a proper open season and tariffs, and [for the Explorers] and the state [to] have the ability to obtain expansion of the pipeline if economically and technically feasible;"
4. "provision for the reaffirmation of Alaska Natural Gas Transportation Act of 1976 and moderniz[ation] of that Act as necessary;"

5. "provisions for federal financial incentives, including accelerated depreciation and an income tax credit that is designed to provide mitigation of long-term natural gas price risks and the risks associated with funding the large capital costs of the project;" and
6. "provisions declaring that the content of [provisions] (2) – (5) is not intended to exclude supply of Alaska North Slope natural gas to markets in the form of LNG or GTL."

Attachment "B." HJR 44 overwhelmingly passed the Alaska Legislature.

During February and early March, many modifications to S. 1766 were circulated, proposed and rumored. The producers were proposing amendments without sharing those amendments with the state. Often, Senator Murkowski's staff would expect Senator Torgerson to respond to amendments on very short notice. During January, the legislative budget & audit committee authorized Senator Torgerson to hire Karol Lyn Newman of the law firm of Hogan & Hartson to advise the Alaska legislature on the Pipeline Act and to monitor that legislation for the legislature. Her assistance was very valuable.

During this time frame, some of the producers continued to oppose a ban on the over the top route. They all seemed to be opposed to ensuring access for in-state use on any basis with teeth. They also all seemed to be opposed to providing for expansion of a pipeline. Senator Torgerson spent many hours with Senator Murkowski's staff, the legislature's attorneys in D.C., the governor's office, and the producers explaining the Joint Committee's position.

Ultimately, a Senate version of an Energy bill passed that body in late April of 2002. The following compares the Senate Energy bill with the positions taken by the Alaska Legislature in HJR 44 and in the proposal adopted by the Joint Committee.

COMPARISONS OF THE SENATE ENERGY BILL WITH POSTIONS OF THE ALASKA LEGISLATURE

Routing

The Alaska Legislature requested a provision banning a pipeline project with a route traversing east through the Beaufort Sea and then entering Canada. This provision was adopted. Sec. 704(d).

In-State Access

The Alaska Legislature requested an amendment that Alaskans have access to the pipeline for in-state consumption and value-added manufacture on a fair and reasonable basis and that the Regulatory Commission of Alaska play a role in determining that access and tariffs relating to that access in conjunction with the Federal Regulatory

Energy Commission (FERC). In essence, the Alaska Legislature was seeking a provision similar to that contained in the ANGTA, which gives the state "special rights" pertaining to access for in-state use of royalty gas. Section 13(b) of the ANGTA provides:

> "The State of Alaska is authorized to ship its royalty gas on the approved transportation system for use within Alaska and ... to withdraw such gas from the interstate market for use within Alaska; the [FERC] **shall** issue all authorizations to effectuate such shipment and withdrawal subject only to review by the Commission only of the justness and reasonableness of the rate charged for such transportation."

(Emphasis added). In essence, ANGTA provides that the state **shall** be given access for the shipment of the state's royalty share. The Senate Bill provides that the FERC, upon the state's request, **may** provide for reasonable access for state royalty gas, a weakening of the state's rights. Sec. 704(h). Additionally, the Senate Bill says that granting such access cannot increase the rates of existing shippers. The Senate Bill also requires that the holder of a FERC certificate for a pipeline project conduct a study of in-state needs, including tie-in points along the pipeline project for in-state access. Sec. 704 (g). The study, however, does not have to be approved by an independent agency.

The Alaska Legislature also requested that the Regulatory Commission of Alaska (RCA) and the FERC jointly set the rates for in-state transportation of gas. The Senate Bill provides that the FERC alone will set the rates although it first must confer with the state. Sec. 709(c).

Explorer Access

The Alaska Legislature requested provisions for access to the pipeline by Explorers on a fair and reasonable basis, including a proper open season and tariffs. The Senate Bill contains an open season provision that allows the FERC to establish regulations and procedures governing any open season, a provision that the FERC consider the effect on competition in adopting those procedures, and, for any open season beyond the initial one, those procedures maximize the opportunity for shipment of gas from units other than Prudhoe Bay and Point Thompson. Sec. 704(e).

The Alaska Legislature also requested a provision that the Explorers and the state have the ability to obtain expansion of the pipeline from the FERC if economically and technically feasible. The Act grants this authority, although it requires that the FERC make many stringent findings. Sec. 706(a)&(b).

The Joint Committee requested a provision that explorers only pay for conditioning services that they use. This provision was not adopted.

The Joint Committee requested that the term "Alaska North Slope gas" be expanded to include gas resources in the Foothills and in Nenana basin surrounding Fairbanks. This provision was included in the Act. Sec. 713(1).

Finally, it is noteworthy that one of the purposes of the Act is "to establish a process for providing access to such transportation project in order to promote competition in the exploration, development and production of Alaska natural gas." Sec. 703(1). This recognizes some of the findings made by the Alaska Legislature in passing HJR 44.

Reaffirm and Modernize ANGTA

The Alaska Legislature requested a "provision for the reaffirmation of the Alaska Natural Gas Transportation Act of 1976 and moderniz[ation] of that Act as necessary." The Joint Committee also requested that there be provisions to protect the presidential waiver granted to the YPC project and that the possibility of supplying LNG to the market be protected. Provisions substantially similar to the Legislature's and the Joint Committee's proposals were adopted. Sec. 703(1); Sec. 712(a)&(b).

Other ANGTA requests by the Joint Committee including elimination of the Dempster Lateral requirement, creation of HUBs, and no tariff charges for previously performed work that has to be duplicated were not adopted.

Jobs

The Joint Committee requested a provision calling for approval of a project labor agreement for the project. Section 714 of the Senate Bill states the "Sense of the Senate and "urges the sponsors of the pipeline project to make every effort ... to negotiate a project labor agreement to expedite construction of the pipeline."

The Joint Committee also requested that Congress approve a preference for qualified Alaskan businesses for the construction and maintenance of the pipeline. Although the Senate did not approve a preference, it did pass several provisions to enhance the opportunities for Alaska employees and contractors. Sec. 715. They include:

1. The Secretary of Labor is required to prepare a report setting forth a program to train Alaska residents in the skills and crafts required to design, construct and operate a pipeline to enhance employment and contracting opportunities for Alaskan residents.
2. The Report should recommend needed changes to laws or regulations that act as a deterrent to hiring Alaskans or contracting with Alaskans.
3. The Secretary of Labor must establish training centers within Alaska to train Alaskans in the skills and crafts necessary.
4. $20,000,000 is appropriated to the Secretary to carry out these programs.

Financial Proposals

The Joint Committee opposed incentives for foreign LNG production and none are in the Act. The Alaska Legislature requested provisions for federal financial incentives, including accelerated depreciation and an income tax credit that is designed to provide

mitigation of long-term natural gas price risks and the risks associated with funding the large capital costs of the project. The Senate Bill does not contain an accelerated depreciation provision although there is some speculation that it will be adopted in conference committee. The Senate Bill, however, does provide for a federal loan guarantee of up to $10 billion. More significantly, it contains a price risk reduction mechanism. Section 2503. The mechanism provides a seller of gas who gets less than $3.25, inflation adjusted, shall be given a tax credit. If the price is greater than $4.85, any previous credits must be paid back until all previous credits are repaid. This provides a major boost to the economics of the Alaska pipeline. Our lobbyists, Hogan & Hartson, report that at least one Senator wants the loan guarantee provision removed from the bill because he was led to believe that if risk mechanism passed the loan guarantee would be taken out of the bill.

WAY FORWARD
April 2002 and Beyond

Given that there are substantial disparities between the House and Senate Energy versions of the Energy Bill, there will be a conference committee between the Senate and the House. There are substantial questions whether and when a compromise will be reached. See Attachment "D." Our lobbyists report that: "Due to controversial differences between the two versions of the legislation, the conference negotiations could prove to be lengthy and difficult."

We know that the Producers have been diligently working to have some of the provisions most beneficial to Alaska, including in-state use of gas, explorer access, and expansion, stripped out of the bill in conference committee. Moreover, at least one of the Producers is working to remove the ban on the over-the-top route. That same Producer is working against the subsidies in the act including the loan guarantee and price risk reduction mechanism. See Attachment "D."

The price risk mechanism has generated considerable controversy, particularly in Canada. See Attachment "D." The Canadians are concerned that it will delay construction of the proposed Mackenzie Delta pipeline and that it will depress Canadian gas production. Producers in the lower 48 are also worried that the mechanism might affect their production.

Appointments from the Senate side have been made to the conference committee. Senator Murkowski is one of the appointees. The House members have not been appointed yet. Most observers believe that Congressman Young will be appointed. When the committee will meet is anybody's guess. Congressman Young has been quoted as saying, "There's no big rush [to get going], because the Senate bill doesn't produce any energy." Attachment "D."

Senator Torgerson, as chairman of the Joint Committee, plans to work with the conference committee to try to change some of the provisions in the Senate Bill to further

benefit the citizens of Alaska. He anticipates making reports to the Joint Committee as information becomes available.

ATTACHMENT A:

12 PROPOSALS OF FEDERAL LEGISLATION BY JOINT COMMITTEE

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672
2962 SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPLINES, 2001-02

ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

Official Business

Senator John Torgerson, Chair
Senator Rick Halford
Senator Pete Kelly
Senator Johnny Ellis

Representative Joe Green, Vice-Chair
Representative Brian Porter
Representative Scott Ogan
Representative John Davies

12 Proposals on Federal Legislation

Proposal # 1

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress reaffirm that the Alaska Natural Gas Transportation Act (ANGTA) is the prevailing law with respect to a transportation system for delivery of Alaska natural gas to ~~Alaska~~, the contiguous States, and other markets, and the construction and initial operation of that system.

The Joint Committee on Natural Gas Pipelines also respectfully requests that Congress allow certain amendments to ANGTA to modernize the act without changing the basic nature and general route of the approved transportation system or otherwise preventing or impairing in any significant respect the expeditious construction and initial operation of the transportation system.

Justification for Proposal # 1
Before the enactment of ANGTA there were three competitive proposals for an Alaska Natural Gas Transportation System. Specifically those proposals were:

1) the Arctic Gas Project, which proposed an overland pipeline extending from Prudhoe Bay, across the North Slope of Alaska to the Canadian Mackenzie Delta and thence southerly through Canada to the lower forty-eight states;
2) the El Paso LNG Project, which proposed an overland pipeline extending from Prudhoe Bay to Southern Alaska, where the gas would have been liquefied and transported by tankers to terminals in the western United States; and
3) the Alcan Pipeline Project, referred to in Canada as the Alaska Highway Pipeline Project, which proposed an overland pipeline

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extending from Prudhoe Bay to Fairbanks, Alaska, and thence southeasterly through western Canada to the lower forty-eight states.

All of these proposals were filed under the Natural Gas Act, debated by FERC, and Congress passed ANGTA, which authorized the President to select a route. The President then approved the ALCAN route and entered into a treaty with Canada, which were later confirmed by Congress. The Canadian Parliament also passed the Northern Pipeline Act, the equivalent of ANGTA. ANGTA was never repealed. In fact, in 1992 the federal inspector recommended that ANGTA be abolished, but Congress rejected that notion.

Proposal # 2

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress adopt provisions that prohibit the over-the-top route through the Beaufort Sea as a pipeline route.

Justification for Proposal # 2

- The Alaska Legislature has banned this route in Senate Bill 164.
- The House of Representatives in Congress has adopted an amendment in the Energy Bill to ban this route.
- This route seriously decreases the benefits Alaskan's will receive from the development of natural gas.
- The North Slope Borough and the Alaska Eskimo Whaling Captains oppose this route.

Proposal # 3

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress create a mechanism for allowing the transparent and fair distribution of the costs allowed to be included in the tariffs associated with a conditioning plant(s).

Justification for Proposal # 3

Other producers will likely discover gas downstream from access to a conditioning plant in Prudhoe Bay that will require them to construct an additional conditioning plant. These producers will need to be treated fairly with regard to tariffs to encourage development and exploration of all North Slope gas resources.

Proposal # 4

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to eliminate the Dempster-Lateral route from provisions in ANGTA, if necessary.

Justification for Proposal # 4

The original version of ANGTA included approval for the construction of a Dempster-Lateral pipeline to deliver natural gas to market from the Northwest Territories. The Northwest Territories has developed plans for their own pipeline route to Alberta, making the Dempster-Lateral line obsolete.

Proposal # 5

The Joint Committee on Natural Gas Pipelines respectfully requests that the Congress pass legislation that limits tariff charges for prior work to compensation for work done that does not have to be duplicated and which is deemed appropriate to the current transportation system.

Justification for Proposal # 5

The current owner of the authorizations under ANGTA is Foothills Pipeline Ltd. Previously, Foothills had several partners, which over time have withdrawn from the partnership. The withdrawn partners spent funds in support of the ANGTA route and have filed documents with the FERC to include recovery of those costs in any tariff for transportation of Alaska natural gas. Foothills has been negotiating with the withdrawn partners to resolve this outstanding liability. However, those negotiations have not been successful to date.

Foothills and its partners should be compensated for the work done in furtherance of the ANGTA system that does not need to be duplicated. If the work needs to be redone or modernized, they should not be entitled to collect for the funds previously expended. Accordingly, the Joint Committee should support this request.

Proposal # 6

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress pass legislation to assure that Alaska have fair and reasonable access to gas produced within the State and to create a joint board consisting of members appointed from the Federal Energy and Regulatory Commission and the Regulatory Commission of Alaska to recommend access and tariffs that affect the state of Alaska.

Justification for Proposal # 6

Unlike the Trans-Alaska Transportation System for oil, the Natural Gas Act does not provide for the Regulatory Commission of Alaska to set rates for gas used in Alaska. Although section 13(b) of ANGTA provides that the state is authorized to ship its royalty gas on the approved system for use within Alaska and to withdraw such gas from the interstate market for use within Alaska, it does not deal specifically with how Alaska delivery points along the line will be approved. Access to gas is necessary for social and economic development of Alaska. Alaska's regulatory commission should be part of a team that determines how intra-state access and rates are determined.

Proposal # 7

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to develop a formula that would allow for the setting of different tariff rates for natural gas distribution points along the route. (HUBS)

Justification for Proposal # 7

Alaska is studying different proposals for usage of natural gas within the state, including several proposals for LNG facilities, a petrochemical plant, several GTL plants, and in-state usage by communities. It is important to be able to set the tariff at different rates to allow these take off points.

Proposal # 8

The Joint Committee on Natural Gas Pipelines respectfully requests that the Congress pass legislation to assure that gas producers that do not have an ownership interest in the pipeline have fair and reasonable access to space on the pipeline and the ability to obtain expansion capacity of the pipeline.

Justification for Proposal # 8

ANGTA originally precluded the Producers from participating in the ownership of the gas pipeline. In 1981, a waiver was sought and obtained by President Reagan to permit the Producers to have an ownership share in the pipeline. Their participation, however, had to be approved by the FERC and could be approved only after consideration of the advice from the Attorney General and upon a finding by FERC that the participation would not (a) be inconsistent with the antitrust laws or (b) in and of itself create restrictions on access to the transportation system for non-owner shippers or restrictions on capacity expansion.

Alaska has much more gas than that contained in known fields. Current estimates provide that there is greater than 100 tcf of gas undiscovered on the Alaska North Slope. Currently, companies are considering exploring for such gas. If discoveries are made, that gas will need access to the pipeline on fair and reasonable terms. If significant discoveries are made after the initial capacity is filled, the pipeline will need to be expanded and any expansion request needs to be determined on fair and reasonable terms. Accordingly, the law must be clear that the FERC has the authority to make such determinations.

Proposal # 9

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to approve a provision for project labor agreements.

Proposal # 10

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to approve a preference for qualified Alaskan businesses for the construction and maintenance of a natural gas pipeline.

Proposal # 11

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress pass legislation that prohibits tax incentives for LNG from sources outside of North America.

Justification for Proposal # 11

The President and Congress have recommended a variety of incentives as part of a national energy policy. Alaska natural gas is in competition with LNG imported from foreign sources to supply gas to the lower 48 states. It is the policy of the United States to reduce dependence on foreign energy sources. Accordingly, Congress should not pass any law that gives tax incentives to facilities importing LNG from sources outside North America. Rather, Congress should enact incentives that benefit production from the frontier areas of the United States, including Alaska. Otherwise, United States gas in frontier areas may be stranded.

Proposal # 12

The Joint Committee on Natural Gas Pipelines respectfully requests that the Congress pass legislation providing a tax incentive that allows for an accelerated depreciation schedule of seven years for Alaska natural gas brought to United States markets.

Justification for Proposal # 12

The President and the Congress has recommended a variety of incentives as part of a national energy policy. It is the policy of the United States to reduce dependence on foreign energy sources. Alaska has significant gas resources that can reduce that dependence and bring cleaner burning fuel to United States markets. However, the construction of a pipeline to the lower 48 would cost billions of dollars and involve significant risk. Accordingly, Congress should enact tax incentives, such as accelerated depreciation, investment tax credits, and downside price tax credits that benefit gas production from Alaska.

ATTACHMENT B:

HJR 44

SCS FOR CS FOR HOUSE JOINT RESOLUTION NO. 44(RES) am S(reengrossed)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SECOND LEGISLATURE - SECOND SESSION

BY THE SENATE RESOURCES COMMITTEE

Amended: 4/10/02
Offered: 4/4/02

Sponsor(s): HOUSE SPECIAL COMMITTEE ON OIL AND GAS BY REQUEST OF THE JOINT COMMITTEE ON NATURAL GAS PIPELINES

A RESOLUTION

Strongly urging the President of the United States, the United States Congress, and appropriate federal officials to support the construction and operation of the Alaska Highway Natural Gas Pipeline route.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS the Alaska North Slope (ANS) has the largest known, discovered natural gas resources, estimated to be 35 trillion cubic feet, in the United States and estimated, undiscovered gas resources in excess of 100 trillion cubic feet; and

WHEREAS demand for natural gas in the lower 48 states is expected to experience record growth, rising from approximately 22 trillion cubic feet a year in 2000 to 30 - 35 trillion cubic feet a year in 2020, with some experts predicting demand to be as large as 50 trillion cubic feet a year in 2020; and

WHEREAS the lower 48 states have an inadequate resource base to meet this expected demand and experts expect that more natural gas will have to be imported from Canada and from other countries in the form of liquefied natural gas (LNG); and

WHEREAS the near record drilling in the last two years in the lower 48 failed to

provide any significant gas supply increase and many experts are questioning whether other United States frontier areas like the deepwater Gulf of Mexico will be able to deliver material new gas supplies and, therefore, more imports may be required than previously thought; and

WHEREAS it is important for the United States to have a reliable and affordable source of domestic natural gas for its citizens and businesses, and for national security, especially given the recent tragic events; and

WHEREAS energy supply disruptions have significant negative effect on the United States economy, including the losses of tens of millions of United States jobs; and

WHEREAS if the United States imports significant amounts of LNG, it can be subjected to the market power of the exporting country through mechanisms such as embargos and price making; and

WHEREAS ANS is one of few known locations in the United States that can supply significant natural gas supplies to the lower 48 for years to come; and

WHEREAS, given these supply and demand projections, several companies and entities have studied three different pipeline routes, including a "northern" route, running off the shore of the Arctic National Wildlife Refuge in the Beaufort Sea to the Mackenzie Delta and south through Canada to the lower 48; a "southern" route along the Alaska Highway through Canada to the lower 48; and an "LNG" route adjacent to the Trans Alaska Pipeline System pipeline to Valdez and LNG tankers for delivery to California; and

WHEREAS, in 1976, Congress passed the Alaska Natural Gas Transportation Act of 1976 (ANGTA) authorizing the President to select a route to transport natural gas from ANS to the lower 48 and providing procedures to expedite the construction and operation of the selected route; and

WHEREAS, in 1977, following lengthy public hearings and negotiations with Canada, the President issued a decision ("President's Decision") choosing the southern route and selecting the predecessor of a consortium of pipeline companies headed by Foothills Pipe Lines, Ltd. ("Pipeline Companies") to construct and operate the Alaska segment of the project; and

WHEREAS the Alaska Gas Producers Pipeline Team ("Producers") has proposed new federal enabling legislation that is currently being debated in the United States Senate; and

WHEREAS the Majority Leader of the United States Senate has introduced the Energy Policy Act of 2002, which contains the Alaska Natural Gas Pipeline Act of 2002 ("Pipeline Act"); and

WHEREAS the Pipeline Act is not opposed by the Pipeline Companies, and they desire certain amendments to the ANGTA to modernize it; and

WHEREAS ANGTA granted the State of Alaska "authoriz[ation] to ship its royalty gas on the approved transportation system for use within Alaska and . . . to withdraw such gas from the interstate market for use within Alaska," which rights will be impaired if a northern route is followed; and

WHEREAS President Carter's decision in support of the southern route explicitly recognized that it could "supply the energy base required for long-term economic development" within Alaska and it could supply natural gas to communities within Alaska along the route as well as other Alaska communities through local distribution lines, and these potential benefits will be lost if a northern route is followed; and

WHEREAS the United States Senate has concurred with the United States House of Representatives to oppose the northern route and has expressed its support for the southern route; and

WHEREAS the southern route presents the United States with petrochemical extraction opportunities in the United States while the northern route does not; and

WHEREAS a northern route pipeline could not easily be expanded to increase the volume of gas when needed; and

WHEREAS the southern route provides petrochemical extraction opportunities in the United States and other marketing opportunities for ANS gas, including gas to liquids (GTL) and LNG, to the West Coast or Asia; and

WHEREAS it is widely recognized that maximum benefit to Alaskans from the commercialization of ANS natural gas lies in market exposure for that gas, opportunities for in-state use of the natural gas, and for participation by Alaskans in construction, maintenance, and operation of the gas pipeline transportation project, and the recovery of revenue by the state from the development, transport, and sale of ANS gas reserves; and

WHEREAS the Alaska State Legislature has expressed a preference for the expedited construction and operation of a natural gas pipeline along a southern route and has authorized

funds to conduct various studies regarding a natural gas pipeline, including the study of in-state natural gas demand, natural gas supply, a natural gas fiscal system, and the effect of natural gas sales on the Prudhoe Bay reservoir; and

WHEREAS the Twenty-Second Alaska State Legislature established the Joint Committee on Natural Gas Pipelines ("Joint Committee") to take whatever action may be appropriate to ensure that the best interests of the state are protected; and

WHEREAS it is vital for the continued exploration and development of natural gas resources on the ANS that oil and gas companies that do not have an ownership interest in the pipeline ("Explorers") have access to it on fair and reasonable terms and have the ability to seek expansion of the pipeline when economically and technically feasible; and the Joint Committee adopted recommendations supporting enactment of these provisions in federal law; and

WHEREAS it is vital for the economic development of Alaska that Alaskans and Alaska businesses have access to gas from the pipeline on a fair and reasonable basis, and that the Regulatory Commission of Alaska participate with the Federal Energy Regulatory Commission to develop methods to provide for such access; and the Joint Committee adopted recommendations supporting enactment of these provisions in federal law; and

WHEREAS the Joint Committee has issued various recommendations requesting that Congress reaffirm the validity of ANGTA and modernize it; and

WHEREAS natural gas prices in the lower 48 states periodically fluctuate below those required to adequately cover investment; and

WHEREAS governmental involvement, including tax incentives, is essential and quite common on major projects to enable private enterprises to undertake the risks;

BE IT RESOLVED that the Alaska State Legislature strongly urges the President of the United States, the United States Congress, and appropriate federal officials to actively support the expeditious construction and operation of a natural gas pipeline through Alaska along a southern route; and be it

FURTHER RESOLVED that the Alaska State Legislature strongly urges passage during the first half of 2002 of the Alaska Gas Producers Pipeline Team's federal enabling legislation, so long as it contains a provision similar to that in H.R. 4 banning the over-the-top route and the following amendments:

(1) provisions for Alaskans and Alaska businesses that ensure they have access to the pipeline for in-state consumption and value-added manufacture on a fair and reasonable basis and that the Regulatory Commission of Alaska is part of the process in determining that access;

(2) provisi ns for access to the pipeline by Explorers on a fair and reasonable basis, including a proper open season with fair and reasonable tariffs, and that provide that they and the State have the ability to obtain expansion of the pipeline if economically and technologically feasible;

(3) provisions for the reaffirmation of the validity of the Alaska Natural Gas Transportation Act of 1976 and the modernization of that Act as necessary;

(4) provisions for federal financial incentives, including accelerated depreciation and an income tax credit that is designed to provide mitigation of long-term natural gas price risks and the risks associated with funding the large capital costs of the project; the amount of any tax credit should be limited in operation to periods when natural gas prices are extremely low and recovered when natural gas prices are high; and

(5) specific provisions declaring that the content of amendments (1) - (4) is not intended to exclude supply of Alaska North Slope natural gas to markets in the form of LNG or GTL.

COPIES of this resolution shall be sent to the Honorable George W. Bush, President of the United States; the Honorable Richard B. Cheney, Vice-President of the United States and President of the U.S. Senate; the Honorable J. Dennis Hastert, Speaker of the U.S. House of Representatives; the Honorable Tom Daschle, Majority Leader of the U.S. Senate; the Honorable Trent Lott, Minority Leader of the U.S. Senate; the Honorable Colin Powell, United States Secretary of State; the Honorable Gale Norton, United States Secretary of the Interior; the Honorable Don Evans, United States Secretary of Commerce; the Honorable Spencer Abraham, United States Secretary of Energy; and to the Honorable Ted Stevens and the Honorable Frank Murkowski, U.S. Senators, and the Honorable Don Young, U.S. Representative, members of the Alaska delegation in Congress.



ATTACHMENT C:

ALASKA NATURAL GAS PIPELINE ACT OF 2002 AND CREDIT FOR PRODUCTION OF ALASKA NATURAL GAS IN SENATE BILL

TITLE VII—NATURAL GAS PIPELINES

Subtitle A—Alaska Natural Gas Pipeline

SEC. 701. SHORT TITLE.

This subtitle may be cited as the "Alaska Natural Gas Pipeline Act of 2002".

SEC. 702. FINDINGS.

The Congress finds that:

(1) Construction of a natural gas pipeline system from the Alaskan North Slope to United States markets is in the national interest and will enhance national energy security by providing access to the significant gas reserves in Alaska needed to meet the anticipated demand for natural gas.

(2) The Commission issued a conditional certificate of public convenience and necessity for the Alaska Natural Gas Transportation System, which remains in effect.

SEC. 703. PURPOSES.

The purposes of this subtitle are—

(1) to provide a statutory framework for the expedited approval, construction, and initial operation of an Alaska natural gas transportation project, as an alternative to the framework provided in the Alas-

ka Natural Gas Transportation Act of 1976 (15 U.S.C. 719–719o), which remains in effect;

(2) to establish a process for providing access to such transportation project in order to promote competition in the exploration, development and production of Alaska natural gas;

(3) to clarify Federal authorities under the Alaska Natural Gas Transportation Act; and

(4) to authorize Federal financial assistance to an Alaska natural gas transportation project as provided in this subtitle.

SEC. 704. ISSUANCE OF CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY.

(a) AUTHORITY OF THE COMMISSION.—Notwithstanding the provisions of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719–719o), the Commission may, pursuant to section 7(c) of the Natural Gas Act (15 U.S.C. 717f(c)), consider and act on an application for the issuance of a certificate of public convenience and necessity authorizing the construction and operation of an Alaska natural gas transportation project other than the Alaska Natural Gas Transportation System.

(b) ISSUANCE OF CERTIFICATE.—(1) The Commission shall issue a certificate of public convenience and necessity authorizing the construction and operation of an Alaska

natural gas transportation project under this section if the applicant has satisfied the requirements of section 7(e) of the Natural Gas Act (15 U.S.C. 717f(e)).

(2) In considering an application under this section, the Commission shall presume that—

(A) a public need exists to construct and operate the proposed Alaska natural gas transportation project; and

(B) sufficient downstream capacity will exist to transport the Alaska natural gas moving through such project to markets in the contiguous United States.

(c) EXPEDITED APPROVAL PROCESS.—The Commission shall issue a final order granting or denying any application for a certificate of public convenience and necessity under section 7(c) of the Natural Gas Act (15 U.S.C. 717f(c)) and this section not more than 60 days after the issuance of the final environmental impact statement for that project pursuant to section 705.

(d) PROHIBITION ON CERTAIN PIPELINE ROUTE.—No license, permit, lease, right-of-way, authorization or other approval required under Federal law for the construction of any pipeline to transport natural gas from lands within the Prudhoe Bay oil and gas lease area may be granted for any pipeline that follows a route that traverses—

(1) the submerged lands (as defined by the Submerged Lands Act) beneath, or the adjacent shoreline of, the Beaufort Sea; and

(2) enters Canada at any point north of 68 degrees North latitude.

(e) OPEN SEASON.—Except where an expansion is ordered pursuant to section 706, initial or expansion capacity on any Alaska natural gas transportation project shall be allocated in accordance with procedures to be established by the Commission in regulations governing the conduct of open seasons for such project. Such procedures shall include the criteria for and timing of any open seasons, be consistent with the purposes set forth in section 703(2) and, for any open season for capacity beyond the initial capacity, provide the opportunity for the transportation of natural gas other than from the Prudhoe Bay and Point Thompson units. The Commission shall issue such regulations no later than 120 days after the enactment of this subtitle.

(f) PROJECTS IN THE CONTIGUOUS UNITED STATES.—Applications for additional or expanded pipeline facilities that may be required to transport Alaska natural gas from Canada to markets in the contiguous United States may be made pursuant to the Natural Gas Act. To the extent such pipeline facilities include the expansion of any facility

constructed pursuant to the Alaska Natural Gas Transportation Act of 1976, the provisions of that Act shall continue to apply.

(g) STUDY OF IN-STATE NEEDS.—The holder of the certificate of public convenience and necessity issued, modified, or amended by the Commission for an Alaska natural gas transportation project shall demonstrate that it has conducted a study of Alaska in-State needs, including tie-in points along the Alaska natural gas transportation project for in-State access.

(h) ALASKA ROYALTY GAS.—The Commission, upon the request of the State of Alaska and after a hearing, may provide for reasonable access to the Alaska natural gas transportation project for the State of Alaska or its designee for the transportation of the State's royalty gas for local consumption needs within the State: Provided, That the rates of existing shippers of subscribed capacity on such project shall not be increased as a result of such access.

(i) REGULATIONS.—The Commission may issue regulations to carry out the provisions of this section.

SEC. 705. ENVIRONMENTAL REVIEWS.

(a) COMPLIANCE WITH NEPA.—The issuance of a certificate of public convenience and necessity authorizing the construction and operation of any Alaska natural gas transportation project under section 704 shall be treated as

a major Federal action significantly affecting the quality of the human environment within the meaning of section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)).

(b) DESIGNATION OF LEAD AGENCY.—The Commission shall be the lead agency for purposes of complying with the National Environmental Policy Act of 1969, and shall be responsible for preparing the statement required by section 102(2)(c) of that Act (42 U.S.C. 4332(2)(c)) with respect to an Alaska natural gas transportation project under section 704. The Commission shall prepare a single environmental statement under this section, which shall consolidate the environmental reviews of all Federal agencies considering any aspect of the project.

(c) OTHER AGENCIES.—All Federal agencies considering aspects of the construction and operation of an Alaska natural gas transportation project under section 704 shall cooperate with the Commission, and shall comply with deadlines established by the Commission in the preparation of the statement under this section. The statement prepared under this section shall be used by all such agencies to satisfy their responsibilities under section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)) with respect to such project.

(d) EXPEDITED PROCESS.—The Commission shall issue a draft statement under this section not later than 12 months after the Commission determines the application to be complete and shall issue the final statement not later than 6 months after the Commission issues the draft statement, unless the Commission for good cause finds that additional time is needed.

SEC. 706. PIPELINE EXPANSION.

(a) AUTHORITY.—With respect to any Alaska natural gas transportation project, upon the request of one or more persons and after giving notice and an opportunity for a hearing, the Commission may order the expansion of such project if it determines that such expansion is required by the present and future public convenience and necessity.

(b) REQUIREMENTS.—Before ordering an expansion the Commission shall—

(1) approve or establish rates for the expansion service that are designed to ensure the recovery, on an incremental or rolled-in basis, of the cost associated with the expansion (including a reasonable rate of return on investment);

(2) ensure that the rates as established do not require existing shippers on the Alaska natural gas transportation project to subsidize expansion shippers;

(3) find that the proposed shipper will comply with, and the proposed expansion and the expansion of service will be undertaken and implemented based on, terms and conditions consistent with the then-effective tariff of the Alaska natural gas transportation project;

(4) find that the proposed facilities will not adversely affect the financial or economic viability of the Alaska natural gas transportation project;

(5) find that the proposed facilities will not adversely affect the overall operations of the Alaska natural gas transportation project;

(6) find that the proposed facilities will not diminish the contract rights of existing shippers to previously subscribed certificated capacity;

(7) ensure that all necessary environmental reviews have been completed; and

(8) find that adequate downstream facilities exist or are expected to exist to deliver incremental Alaska natural gas to market.

(c) REQUIREMENT FOR A FIRM TRANSPORTATION AGREEMENT.—Any order of the Commission issued pursuant to this section shall be null and void unless the person or persons requesting the order executes a firm transportation agreement with the Alaska natural gas transpor-

tation project within a reasonable period of time as specified in such order.

(d) LIMITATION.—Nothing in this section shall be construed to expand or otherwise affect any authorities of the Commission with respect to any natural gas pipeline located outside the State of Alaska.

(e) REGULATIONS.—The Commission may issue regulations to carry out the provisions of this section.

SEC. 707. FEDERAL COORDINATOR.

(a) ESTABLISHMENT.—There is established as an independent establishment in the executive branch, the Office of the Federal Coordinator for Alaska Natural Gas Transportation Projects.

(b) THE FEDERAL COORDINATOR.—The Office shall be headed by a Federal Coordinator for Alaska Natural Gas Transportation Projects, who shall—

(1) be appointed by the President, by and with the advice of the Senate,

(2) hold office at the pleasure of the President, and

(3) be compensated at the rate prescribed for level III of the Executive Schedule (5 U.S.C. 5314).

(c) DUTIES.—The Federal Coordinator shall be responsible for—

(1) coordinating the expeditious discharge of all activities by Federal agencies with respect to an Alaska natural gas transportation project; and

(2) ensuring the compliance of Federal agencies with the provisions of this subtitle.

(d) REVIEWS AND ACTIONS OF OTHER FEDERAL AGENCIES.—(1) All reviews conducted and actions taken by any Federal officer or agency relating to an Alaska natural gas transportation project authorized under this section shall be expedited, in a manner consistent with completion of the necessary reviews and approvals by the deadlines set forth in this subtitle.

(2) No Federal officer or agency shall have the authority to include terms and conditions that are permitted, but not required, by law on any certificate, right-of-way, permit, lease or other authorization issued to an Alaska natural gas transportation project if the Federal Coordinator determines that the terms and conditions would prevent or impair in any significant respect the expeditious construction and operation of the project.

(3) Unless required by law, no Federal officer or agency shall add to, amend, or abrogate any certificate, right-of-way, permit, lease or other authorization issued to an Alaska natural gas transportation project if the Federal Coordinator determines that such action would prevent or im-

pair in any significant respect the expeditious construction and operation of the project.

(e) STATE COORDINATION.—The Federal Coordinator shall enter into a Joint Surveillance and Monitoring Agreement, approved by the President and the Governor of Alaska, with the State of Alaska similar to that in effect during construction of the Trans-Alaska Oil Pipeline to monitor the construction of the Alaska natural gas transportation project. The Federal Government shall have primary surveillance and monitoring responsibility where the Alaska natural gas transportation project crosses Federal lands and private lands, and the State government shall have primary surveillance and monitoring responsibility where the Alaska natural gas transportation project crosses State lands.

SEC. 708. JUDICIAL REVIEW.

(a) EXCLUSIVE JURISDICTION.—The United States Court of Appeals for the District of Columbia Circuit shall have exclusive jurisdiction to determine—

(1) the validity of any final order or action (including a failure to act) of any Federal agency or officer under this subtitle;

(2) the constitutionality of any provision of this subtitle, or any decision made or action taken thereunder; or

(3) the adequacy of any environmental impact statement prepared under the National Environmental Policy Act of 1969 with respect to any action under this subtitle.

(b) DEADLINE FOR FILING CLAIM.—Claims arising under this subtitle may be brought not later than 60 days after the date of the decision or action giving rise to the claim.

(c) EXPEDITED CONSIDERATION.—The United States Court of Appeals for the District of Columbia Circuit shall set any action brought under subsection (a) of this section for expedited consideration, taking into account the national interest as described in section 702 of this subtitle.

(d) AMENDMENT TO ANGTA.—Section 10(c) of the Alaska Gas Transportation Act of 1976 (15 U.S.C. 719h) is amended by adding the following paragraph:

"(2) EXPEDITED CONSIDERATION.—The United States Court of Appeals for the District of Columbia Circuit shall set any action brought under subsection (a) of this section for expedited consideration, taking into account the national interest described in section 2 of this Act.".

SEC. 709. STATE JURISDICTION OVER IN-STATE DELIVERY OF NATURAL GAS.

(a) LOCAL DISTRIBUTION.—Any facility receiving natural gas from the Alaska natural gas transportation project for delivery to consumers within the State of Alaska shall be deemed to be a local distribution facility within the meaning of section 1(b) of the Natural Gas Act (15 U.S.C. 717), and therefore not subject to the jurisdiction of the Federal Energy Regulatory Commission.

(b) ADDITIONAL PIPELINES.—Nothing in this subtitle, except as provided in subsection 704(d), shall preclude or affect a future gas pipeline that may be constructed to deliver natural gas to Fairbanks, Anchorage, Matanuska-Susitna Valley, or the Kenai peninsula or Valdez or any other site in the State of Alaska for consumption within or distribution outside the State of Alaska.

(c) RATE COORDINATION.—Pursuant to the Natural Gas Act, the Commission shall establish rates for the transportation of natural gas on the Alaska natural gas transportation project. In exercising such authority, the Commission, pursuant to Section 17(b) of the Natural Gas Act (15 U.S.C. 717p), shall confer with the State of Alaska regarding rates (including rate settlements) applicable to natural gas transported on and delivered from the Alaska natural gas transportation project for use within the State of Alaska.

SEC. 710. LOAN GUARANTEE.

(a) AUTHORITY.—The Secretary of Energy may guarantee not more than 80 percent of the principal of any loan made to the holder of a certificate of public convenience and necessity issued under section 704(b) of this Act or section 9 of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719g) for the purpose of constructing an Alaska natural gas transportation project.

(b) CONDITIONS.—(1) The Secretary of Energy may not guarantee a loan under this section unless the guarantee has filed an application for a certificate of public convenience and necessity under section 704(b) of this Act or for an amended certificate under section 9 of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719g) with the Commission not later than 18 months after the date of enactment of this subtitle.

(2) A loan guaranteed under this section shall be made by a financial institution subject to the examination of the Secretary.

(3) Loan requirements, including term, maximum size, collateral requirements and other features shall be determined by the Secretary.

(c) LIMITATION ON AMOUNT.—Commitments to guarantee loans may be made by the Secretary of Energy only to the extent that the total loan principal, any part of which is guaranteed, will not exceed $10,000,000,000.

(d) REGULATIONS.—The Secretary of Energy may issue regulations to carry out the provisions of this section.

(e) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated to the Secretary such sums as may be necessary to cover the cost of loan guarantees, as defined by section 502(5) of the Federal Credit Reform Act of 1990 (2 U.S.C. 661a(5)).

SEC. 711. STUDY OF ALTERNATIVE MEANS OF CONSTRUCTION.

(a) REQUIREMENT OF STUDY.—If no application for the issuance of a certificate or amended certificate of public convenience and necessity authorizing the construction and operation of an Alaska natural gas transportation project has been filed with the Commission within 18 months after the date of enactment of this title, the Secretary of Energy shall conduct a study of alternative approaches to the construction and operation of the project.

(b) SCOPE OF STUDY.—The study shall consider the feasibility of establishing a Government corporation to construct an Alaska natural gas transportation project, and alternative means of providing Federal financing and ownership (including alternative combinations of Government and private corporate ownership) of the project.

(c) CONSULTATION.—In conducting the study, the Secretary of Energy shall consult with the Secretary of the

Treasury and the Secretary of the Army (acting through the Commanding General of the Corps of Engineers).

(d) REPORT.—If the Secretary of Energy is required to conduct a study under subsection (a), he shall submit a report containing the results of the study, his recommendations, and any proposals for legislation to implement his recommendations to the Congress within 6 months after the expiration of the Secretary of Energy's authority to guarantee a loan under section 710.

SEC. 712. CLARIFICATION OF ANGTA STATUS AND AUTHORITIES.

(a) SAVINGS CLAUSE.—Nothing in this subtitle affects any decision, certificate, permit, right-of-way, lease, or other authorization issued under section 9 of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719g) or any Presidential findings or waivers issued in accordance with that Act.

(b) CLARIFICATION OF AUTHORITY TO AMEND TERMS AND CONDITIONS TO MEET CURRENT PROJECT REQUIREMENTS.—Any Federal officer or agency responsible for granting or issuing any certificate, permit, right-of-way, lease, or other authorization under section 9 of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719g) may add to, amend, or abrogate any term or condition included in such certificate, permit, right-of-way, lease, or

other authorization to meet current project requirements (including the physical design, facilities, and tariff specifications), so long as such action does not compel a change in the basic nature and general route of the Alaska Natural Gas Transportation System as designated and described in section 2 of the President's Decision, or would otherwise prevent or impair in any significant respect the expeditious construction and initial operation of such transportation system.

(c) UPDATED ENVIRONMENTAL REVIEWS.—The Secretary of Energy shall require the sponsor of the Alaska Natural Gas Transportation System to submit such updated environmental data, reports, permits, and impact analyses as the Secretary determines are necessary to develop detailed terms, conditions, and compliance plans required by section 5 of the President's Decision.

SEC. 713. DEFINITIONS.

For purposes of this subtitle:

(1) The term "Alaska natural gas" means natural gas derived from the area of the State of Alaska lying north of 64 degrees North latitude.

(2) The term "Alaska natural gas transportation project" means any natural gas pipeline system that carries Alaska natural gas to the border between Alaska and Canada (including related facilities subject to

the jurisdiction of the Commission) that is authorized under either—

(A) the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719–719o); or

(B) section 704 of this subtitle.

(3) The term "Alaska Natural Gas Transportation System" means the Alaska natural gas transportation project authorized under the Alaska Natural Gas Transportation Act of 1976 and designated and described in section 2 of the President's Decision.

(4) The term "Commission" means the Federal Energy Regulatory Commission.

(5) The term "President's Decision" means the Decision and Report to Congress on the Alaska Natural Gas Transportation system issued by the President on September 22, 1977 pursuant to section 7 of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719c) and approved by Public Law 95–158.

SEC. 714. SENSE OF THE SENATE.

It is the sense of the Senate that an Alaska natural gas transportation project will provide significant economic benefits to the United States and Canada. In order to maximize those benefits, the Senate urges the sponsors of the pipeline project to make every effort to use steel that is man-

ufactured or produced in North America and to negotiate a project labor agreement to expedite construction of the pipeline.

SEC. 715. ALASKAN PIPELINE CONSTRUCTION TRAINING PROGRAM.

(a) Within six months after enactment of this Act, the Secretary of Labor (in this section referred to as the "Secretary") shall submit a report to the Committee on Energy and Natural Resources of the United States Senate and the Committee on Resources of the United States House of Representatives setting forth a program to train Alaska residents in the skills and crafts required in the design, construction, and operation of an Alaska gas pipeline system and that will enhance employment and contracting opportunities for Alaskan residents. The report shall also describe any laws, rules, regulations and policies which act as a deterrent to hiring Alaskan residents or contracting with Alaskan residents to perform work on Alaska gas pipelines, together with any recommendations for change. For purposes of this subsection, Alaskan residents shall be defined as those individuals eligible to vote within the State of Alaska on the date of enactment of this Act.

(b) Within 1 year of the date the report is transmitted to Congress, the Secretary shall establish within the State of Alaska, at such locations as are appropriate, one or more

training centers for the express purpose of training Alaskan residents in the skills and crafts necessary in the design, construction and operation of gas pipelines in Alaska. Each such training center shall also train Alaskan residents in the skills required to write, offer, and monitor contracts in support of the design, construction, and operation of Alaska gas pipelines.

(c) In implementing the report and program described in this subsection, the Secretary shall consult with the Alaskan Governor.

(d) There are authorized to be appropriated to the Secretary such sums as may be necessary, but not to exceed $20,000,000 for the purposes of this subsection.

Subtitle B—Operating Pipelines

SEC. 721. ENVIRONMENTAL REVIEW AND PERMITTING OF NATURAL GAS PIPELINE PROJECTS.

(a) INTERAGENCY REVIEW.—The Chairman of the Council on Environmental Quality, in coordination with the Federal Energy Regulatory Commission, shall establish an interagency task force to develop an interagency memorandum of understanding to expedite the environmental review and permitting of natural gas pipeline projects.

(b) MEMBERSHIP OF INTERAGENCY TASK FORCE.—The task force shall consist of—

Credit For Production of

Alaska Natural Gas

SEC. 2503. CREDIT FOR PRODUCTION OF ALASKA NATURAL GAS.

(a) IN GENERAL.—Subpart D of part IV of subchapter A of chapter 1 (relating to business related credits), as

amended by this Act, is amended by adding at the end the following new section:

"SEC. 45M. ALASKA NATURAL GAS.

"(a) IN GENERAL.—For purposes of section 38, the Alaska natural gas credit of any taxpayer for any taxable year is the credit amount per 1,000,000 Btu of Alaska natural gas entering any intake or tie-in point which was derived from an area of the State of Alaska lying north of 64 degrees North latitude, which is attributable to the taxpayer and sold by or on behalf of the taxpayer to an unrelated person during such taxable year (within the meaning of section 45).

"(b) CREDIT AMOUNT.—For purposes of this section—

"(1) IN GENERAL.—The credit amount per 1,000,000 Btu of Alaska natural gas entering any intake or tie-in point which was derived from an area of the State of Alaska lying north of 64 degrees North latitude (determined in United States dollars), is the excess of—

"(A) $3.25, over

"(B) the average monthly price at the AECO C Hub in Alberta, Canada, for Alaska natural gas for the month in which occurs the date of such entering.

"(2) INFLATION ADJUSTMENT.—In the case of any taxable year beginning in a calendar year after the first calendar year ending after the date described in subsection (g)(1), the dollar amount contained in paragraph (1)(A) shall be increased to an amount equal to such dollar amount multiplied by the inflation adjustment factor for such calendar year (determined under section 43(b)(3)(B) by substituting 'the calendar year ending before the date described in section 45M(g)(1)' for '1990').

"(c) ALASKA NATURAL GAS.—For purposes of this section, the term 'Alaska natural gas' means natural gas entering any intake or tie-in point which was derived from an area of the State of Alaska lying north of 64 degrees North latitude produced in compliance with the applicable State and Federal pollution prevention, control, and permit requirements from the area generally known as the North Slope of Alaska (including the continental shelf thereof within the meaning of section 638(l)), determined without regard to the area of the Alaska National Wildlife Refuge (including the continental shelf thereof within the meaning of section 638(l)).

"(d) RECAPTURE.—

"(1) IN GENERAL.—With respect to each 1,000,000 Btu of Alaska natural gas entering any in-

take or tie-in point which was derived from an area of the State of Alaska lying north of 64 degrees North latitude after the date which is 3 years after the date described in subsection (g)(1), if the average monthly price described in subsection (b)(1)(B) exceeds 150 percent of the amount described in subsection (b)(1)(A) for the month in which occurs the date of such entering, the taxpayer's tax under this chapter for the taxable year shall be increased by an amount equal to the lesser of—

"(A) such excess, or

"(B) the aggregate decrease in the credits allowed under section 38 for all prior taxable years which would have resulted if the Alaska natural gas credit received by the taxpayer for such years had been zero.

"(2) SPECIAL RULES.—

"(A) TAX BENEFIT RULE.—The tax for the taxable year shall be increased under paragraph (1) only with respect to credits allowed by reason of this section which were used to reduce tax liability. In the case of credits not so used to reduce tax liability, the carryforwards and carrybacks under section 39 shall be appropriately adjusted.

"(B) NO CREDITS AGAINST TAX.—Any increase in tax under this subsection shall not be treated as a tax imposed by this chapter for purposes of determining the amount of any credit under this chapter or for purposes of section 55.

"(e) APPLICATION OF RULES.—For purposes of this section, rules similar to the rules of paragraphs (3), (4), and (5) of section 45(d) shall apply.

"(f) NO DOUBLE BENEFIT.—The amount of any deduction or other credit allowable under this chapter for any fuel taken into account in computing the amount of the credit determined under subsection (a) shall be reduced by the amount of such credit attributable to such fuel.

"(g) APPLICATION OF SECTION.—This section shall apply to Alaska natural gas entering any intake or tie-in point which was derived from an area of the State of Alaska lying north of 64 degrees North latitude for the period—

"(1) beginning with the later of—

"(A) January 1, 2010, or

"(B) the initial date for the interstate transportation of such Alaska natural gas, and

"(2) except with respect to subsection (d), ending with the date which is 15 years after the date described in paragraph (1).".

(b) CREDIT TREATED AS BUSINESS CREDIT.—Section 38(b), as amended by this Act, is amended by striking "plus" at the end of paragraph (22), by striking the period at the end of paragraph (23) and inserting ", plus", and by adding at the end the following new paragraph:

"(24) The Alaska natural gas credit determined under section 45M(a).".

(c) ALLOWING CREDIT AGAINST ENTIRE REGULAR TAX AND MINIMUM TAX.—

(1) IN GENERAL.—Subsection (c) of section 38 (relating to limitation based on amount of tax), as amended by this Act, is amended by redesignating paragraph (5) as paragraph (6) and by inserting after paragraph (4) the following new paragraph:

"(5) SPECIAL RULES FOR ALASKA NATURAL GAS CREDIT.—

"(A) IN GENERAL.—In the case of the Alaska natural gas credit—

"(i) this section and section 39 shall be applied separately with respect to the credit, and

"(ii) in applying paragraph (1) to the credit—

"(I) the amounts in subparagraphs (A) and (B) thereof shall be treated as being zero, and

"(II) the limitation under paragraph (1) (as modified by subclause (I)) shall be reduced by the credit allowed under subsection (a) for the taxable year (other than the Alaska natural gas credit).

"(B) ALASKA NATURAL GAS CREDIT.—For purposes of this subsection, the term 'Alaska natural gas credit' means the credit allowable under subsection (a) by reason of section 45M(a).".

(2) CONFORMING AMENDMENTS.—Subclause (II) of section 38(c)(2)(A)(ii), as amended by this Act, subclause (II) of section 38(c)(3)(A)(ii), as amended by this Act, and subclause (II) of section 38(c)(4)(A)(ii), as added by this Act, are each amended by inserting "or the Alaska natural gas credit" after "producer credit".

(d) CLERICAL AMENDMENT.—The table of sections for subpart D of part IV of subchapter A of chapter 1, as amended by this Act, is amended by adding at the end the following new item:

"Sec. 45M. Alaska natural gas.".

ATTACHMENT D:

ARTICLES

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EDITORIAL

Adding Up the Energy Bills

Monday, April 29, 2002; Page A20

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NOW THAT the Senate has wrapped up its long-running energy debates, the action will move to a conference committee -- and as House and Senate members try to reconcile the sharp differences between the two versions of the legislation, the potential effect on the Treasury will be painful to contemplate. The two sides started out from different policy points: The House embraced President Bush's goal of increasing domestic energy production, including continued emphasis on fossil fuels, while the Senate at least began with a stronger tilt toward conservation and renewable resources. But they both rely heavily on federal financial incentives to accomplish their objectives. The House produced a measure offering $33.5 billion in tax breaks, tilted toward fuel production. The Senate offers a more modest $14 billion in tax breaks, with an emphasis on conservation and renewable energy -- but then tosses in not only $10 billion in loan guarantees for an Alaska natural gas pipeline but also a provision promising producers a floor price when the gas reaches its destination. As they look for agreement on other difficult issues, it doesn't take much imagination to picture negotiators sweetening the ultimate deal by embracing everybody's payoffs.

That would certainly fit the energy policy tradition of recent years, in which political leaders have shied away from anything that could be remotely construed as requiring sacrifice. A carbon tax, the most efficient means of encouraging conservation and renewable fuels, should have been part of this debate but was never on the table in either the president's energy policy or the legislative deliberations. Members worked with more cumbersome tools: subsidies, tax incentives, regulations. The Senate started out promising tougher requirements on auto fuel efficiency and higher efficiency standards for air conditioning,

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but both fell by the wayside as the bill progressed. A requirement for electricity producers to generate 10 percent of their electricity from renewable sources survived in the Senate bill but was weakened. One provision that should have been removed, a mandate to boost consumption of already-subsidized ethanol, unfortunately still remains in the Senate measure.

The Senate did draw an important line in holding off drilling in the Arctic National Wildlife Refuge, and it took some steps worth noting on climate change, including endorsing a registry for carbon emissions that will become mandatory if it doesn't draw enough voluntary compliance. But even though it contains some worthy provisions, we like the Senate bill less now than when it began and don't see how things will get any better in conference. Of course differences over the Arctic Refuge alone may be enough to guarantee that the energy measure never reaches final passage: House Republican leaders are strongly in favor of the drilling and Senate Democratic leaders equally strong in opposition. At least at the moment, impasse doesn't look like the worst option.

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Subject: Wall Street Journal
Date: Fri, 10 May 2002 07:20:53 -0800
From: Larry Persily <Larry_Persily@revenue.state.ak.us>
Organization: Department of Revenue
To: John C Torgerson <senator_john_torgerson@legis.state.ak.us>, patrick_coughlin@legis.state.ak.us

Canadian Oil Firms Raise Objections To U.S. Tax Credits for Alaska Project

By TAMSIN CARLISLE
Staff Reporter of THE WALL STREET JOURNAL

CALGARY, Alberta -- Billions of dollars in proposed U.S. tax credits for a natural-gas project in Alaska are creating a stir in Canada's oil patch and could escalate into the next big U.S.-Canada trade spat.

Energy companies here worry that the tax credits will distort prices for natural gas, just as they seek to develop vast gas reserves in Canada's western Arctic region.

The recently passed Senate energy bill, containing the proposed tax breaks, is subject to reconciliation with an energy bill previously adopted by the House of Representatives. An omnibus energy bill could be presented to President Bush for his signature by the end of the summer.

Canada's energy minister, Herb Dhaliwal, is threatening to block construction of a natural-gas pipeline along the Alaska Highway unless U.S. and Alaskan legislators rethink their stance. "They tend to forget that if they want the Alaska route, two-thirds of it is going to have to come through Canada," he said recently.

The crux of Canada's problem is the Senate bill, which aims to kick-start a $17 billion project to develop Alaska North Slope natural-gas supplies and to build the pipeline along the Alaska Highway. Gas producers including Exxon Mobil Corp., Phillips Petroleum Corp. and BP PLC that are assessing the feasibility of producing Alaska North Slope gas say the Alaska Highway project isn't currently economic on its own merits. But earlier this year, Congress effectively mandated that pipeline route by banning an alternative route beneath the Arctic Ocean and through Canada, citing environmental reasons.

To encourage producers, the Senate bill would -- through tax credits -- guarantee them a floor price for natural gas of $3.25 per million British thermal units of gas at a distribution hub in Alberta. Although U.S. gas prices have strengthened in recent weeks, they languished well below the proposed floor price during most of the past winter.

Even some U.S. producers that ostensibly stand to benefit from the proposed tax breaks want the government to stay out. "We would prefer just to let the natural forces of supply and demand work. We would prefer just to wait until the project can support itself," says Exxon Mobil spokesman Bob Davis, adding that prior congressional interference has limited gas producers' flexibility on projects.

Canadian critics say the proposed tax credits would interfere with free trade in North America's natural-gas market -- a linchpin of the North American Free Trade Agreement that Canada fought hard to get. Some U.S. analysts say American taxpayers will pay billions of dollars more for natural gas under the Senate plan than they would without it.

Northwest Territories Premier Stephen Kakfwi says his region's energy

industry could shut down if huge volumes of subsidized Alaska gas flood the market, making it uneconomic for gas producers to develop northern Canadian reserves.

Even though the proposed Alaska tax credits aren't yet enacted, natural-gas producers "would have to be crazy" to invest in northern Canadian energy exploration now, "when they can move just 100 miles west and eliminate a big uncertainty" on price, says Harvie Andre, a former Canadian politician who now heads the Canadian unit of Arctic Resources Co., Houston. Arctic Resources sponsored the pipeline route that Congress rejected.

Indeed, Petro-Canada, a major natural-gas explorer in northern Canada, has just snapped up exploration prospects in Alaska. Petro-Canada Chief Executive Officer Ronald Brenneman says the Calgary company is "hedging its bets."

Report on Business: Canadian

Pipeline subsidies seen as inadequate Petroleum producers say Alaska project uneconomic even with U.S. energy bill

LILY NGUYEN

05/10/2002
The Globe and Mail
Metro
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CALGARY -- Petroleum producers considering a massive **Alaska** natural gas **pipeline** said even billions of dollars in subsidies being offered under a U.S. energy bill will not be enough to give the project the green light.

"It's our view the project is and remains uneconomic," said Bob Davis, a spokesman for Exxon Mobil Corp. of Irving, Tex., one of three supermajors looking at an **Alaska pipeline** , along with London-based BP PLC and Phillips Petroleum Co. of Bartlesville, Okla.

Ronnie Chappell, a spokesman for BP's **Alaska** unit, agreed.

"This does not change the fundamental economics of the project," Mr. Chappell said from Anchorage, **Alaska** .

Even Phillips, the company pushing hardest for the subsidies, agreed the potential subsidies would not be enough to allow the project to proceed.

"I don't want to give the impression that all of a sudden we're building a **pipeline** ," said Phillips spokeswoman Dawn Patience. She added, however, that Phillips believes the subsidies will keep the project from being shelved altogether.

A U.S. energy bill passed by the Senate last month contains provisions proposing an economic boost to the **pipeline** of billions of dollars in loan guarantees and other incentives.

The provisions were in response to a $100-million feasibility study done by the Alaskan producers over the last two years -- and completed last month -- that concluded it didn't make economic sense in the current market to build a **pipeline** to ship gas from **Alaska** to the Lower 48.

The subsidy provisions could have major implications for a competing project to build a **pipeline** from the **Mackenzie** Delta of the Northwest Territories.

Proponents of that project -- most notably NWT Premier Stephen Kakfwi -- have warned that the subsidies could strand **Mackenzie** Delta gas. He argues the subsidies could fast-track the much-larger **Alaska** project, thereby flooding the gas market and rendering **Mackenzie** gas unnecessary. Federal Natural Resources Minister Herb Dhaliwal has warned that Canada could drop its neutral stance on which **pipeline** goes ahead first if the

United States pushes its own preference.

The **Mackenzie** Delta producers -- led by Toronto-based Imperial Oil Ltd. and including Houston-based Conoco Inc. and Shell Canada Ltd. of Calgary -- have said they will wait and see if the bill is passed with the subsidy provisions before commenting on what effect it could have on an NWT **pipeline** .

"The worries about subsidies are at the moment hypothetical," said Peter Hunt of Conoco, adding that his group is proceeding with planning on the Delta **pipeline** .

BP's Mr. Chappell said that whether or not the subsidies are passed, Alaskan producers do not believe the **pipeline** project can go ahead without the backing of Canada, since two-thirds of the **pipeline** would cross Canadian territory.

"Canadian support for this **pipeline** is absolutely essential," he said.

Mr. Davis said part of the reason the **Alaska** project remains uneconomic is because previous cost estimates for a **pipeline** had to be raised to $19-billion from $17-billion, because a larger capacity pipe than previously thought would be needed.

But he added that Exxon is not interested in higher subsidies. In fact, the company is opposed to the subsidy provision in the bill because it believes it distorts market forces, he said.

"We would prefer to let the natural market forces operate and not create artificial support, which creates an unlevel playing field."

Mr. Davis declined to comment on whether Exxon would employ the subsidies if they are passed.

Financial Post
ExxonMobil wants U.S. gas subsidy bill stopped: Pipeline wars: 'Let market forces work on their own,' says industry giant
Claudia Cattaneo, Calgary Bureau Chief

05/09/2002
National Post
National
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CALGARY - ExxonMobil Corp., the top natural gas reserve owner in **Alaska** , says it disagrees with U.S. government subsidies to support building of a natural gas **pipeline** along the **Alaska** Highway and favours a smaller project from Canada's **Mackenzie** Delta.

Bob Davis, a spokesman for the Irving, Tex-based company, said yesterday a more in-depth evaluation of an **Alaska** line shows costs have escalated since estimates were first made last fall, reinforcing the firm's views that the project remains uneconomic.

"Speaking for ExxonMobil, we are not looking for subsidies and it really doesn't change our thinking on the economics of the project," Mr. Davis said. "We philosophically usually do not agree with subsidies, because it's our view that we like let market forces and market conditions to work on their own. If it's not economic -- which the **Alaska** project is not now -- we have always said we'd rather wait until we can improve it on our own actions or wait until the market conditions support the project."

The conclusion means that a **Mackenzie** Valley project, at an estimated cost of about $3-billion, "looks very optimistic ... that's a project that holds a lot of promise."

ExxonMobil is the largest owner of natural gas reserves in **Alaska** 's North Slope. The company is also the majority owner of Toronto-based Imperial Oil Ltd., which holds the largest reserves in the **Mackenzie** Delta and is leading efforts to build a smaller **pipeline** down the **Mackenzie** River Valley, linking to Alberta's existing network. The Canadian project would not require subsidies.

It's unlikely the two projects would move ahead at the same time because of the large financial resources, equipment and labour required for each one. As well, the first one to start could impact the economics of the other by pushing down the commodity's market price by increasing supplies.

Mr. Davis made the comments as a controversial U.S. Senate bill works its way through the U.S. Congress. The bill, aimed at improving the **Alaska** line's economics, would create a US$3.25 per thousand cubic feet floor price on natural gas shipped from **Alaska** . Under the plan, promoted mostly by the state of **Alaska** , energy producers would also receive loan guarantees to build the **pipeline** .

ExxonMobil, the world's largest publicly traded oil company, teamed up with Phillips Petroleum Co. and BP PLC last year on a US$125-million study that looked at the feasibility of building pipelines from **Alaska** 's Prudhoe Bay area.

The study concluded costs were too high regardless of the route. A southern route along the **Alaska** Highway through the Yukon would cost US$17.2-billion and a northern route (known as the over-the-top route) through the Arctic Ocean to the **Mackenzie** River Delta and down the **Mackenzie** Valley would cost US$15.1-billion.

Further evaluation by ExxonMobil showed that both routes would cost about US$2-billion more -- or US$19.4-billion for the southern route and US$18.6-billion for the northern route -- after factoring in larger start-up, permitting, insurance, project

management costs, as well as increased **pipeline** capacity to 4.5 billion cubic feet, from 4 billion cubic feet. Mr. Davis stressed that even those numbers are uncertain.

"The producers just recently announced in a series of meetings that the study we have done on the **Alaska pipeline** indicates that it's just not economic at this time, so that project does not look like it's going to go forward at this time. In fact, we pretty much wrapped up the work we are doing and the people who were up there for that year-long study."

Mr. Davis said his firm would have to see a natural gas price of US$3 to US$3.50 per thousand cubic feet on a long-term basis for the **pipeline** to move ahead.

Mr. Davis said his firm also views the Senate bill as a "strong negative" because it prohibits the over-the-top route.

The bill has also come under heavy criticism in recent days from Canadian and U.S. producers with interests in the **Mackenzie** Delta, as well as from the Northwest Territo es and Herb Dhaliwal, the federal Energy Minister. They are concerned that such a subsid y would distort the North American market for natural gas and undermine development of **Mackenzie** reserves.

The Canadian **pipeline** would be owned by Imperial Oil and its partners Conoco Inc. and Royal Dutch/Shell Group, as well as Canadian natives.

Editorial
A better pipeline for northern gas

05/09/2002
The Globe and Mail
Metro
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In the race to deliver rich far-north natural gas reserves to market, U.S. lawmakers have decided to play favourites. Maybe it's time the Canadian government did likewise.

The U.S. Senate recently amended an energy bill to require that any **pipeline** for Alaskan natural gas follow a circuitous and costly route down through the middle of the state (see map below), and to provide up to $10-billion (U.S.) in subsidies to the gas producers who would finance such a **pipeline** .

The amendments give the economically unviable **Alaska** Highway **pipeline** a big advantage over a competing, less costly proposal to deliver northern gas along a Canadian route, running along the **Mackenzie** River valley. If the House of Representatives and President George W. Bush approve the bill with the amendments intact, the **Mackenzie** project could face an indefinite delay, bringing development of Canada's northern natural gas to a screeching halt.

Ottawa has tried to remain neutral on the route, mainly because choosing sides would mean supporting one northern territory over another. The **Alaska** Highway **pipeline** would include a significant section through Yukon, while the **Mackenzie** project is a key cog in the Northwest Territories' economic development plans. But given the U.S. Senate's self-serving stance, it is clear that the federal government should throw its support behind the project that would most benefit Canada, the **Mackenzie** route.

The NWT government estimates the **Mackenzie** project would ultimately contribute up to $57-billion (Canadian) to Canada's GDP, almost double Yukon's estimate of the contribution of the **Alaska** project to Canada's economy. Since the federal government holds the rights to Northwest Territories oil and gas, it would receive a huge windfall in royalties from **Mackenzie** Delta gas sales. Those revenues would benefit all Canadians.

Conceivably, both the **Alaska** Highway and **Mackenzie** pipelines could profitably co-exist. However, most experts agree there isn't sufficient manufacturing capacity or skilled labour to support simultaneous construction of both projects. If a heavily subsidized **Alaska** project went ahead first, flooding the market with artificially cheap supplies, the **Mackenzie pipeline** could be delayed for years or even decades.

A third option, which makes the most sense for both Alaskan and **Mackenzie** producers, is the "over the top" route. This would involve an underwater **pipeline** through the Beaufort Sea from Prudhoe Bay, **Alaska** , to Inuvik, NWT, which would connect to a bigger **Mackenzie pipeline** to deliver both Canadian and Alaskan natural gas to southern markets.

The over-the-top route is billions cheaper than the **Alaska** Highway route. The costs would be shared among Canadian and U.S. producers, reducing risks to individual companies. The economies of scale would significantly lower production costs and raise profits for all producers, generating higher royalty revenues for the governments of **Alaska** and Canada.

The over-the-top route is simply the best way to deliver the most natural gas to the energy-hungry U.S. market, and would demonstrate co-operation between Canada and the United States on a major initiative to improve North America's energy self-sufficiency. All of these are stated goals in President Bush's national energy policy.

Yet the U.S. Senate instead chose to cave in to shortsighted Alaskan political interests. In doing so, it may help **Alaska** land the many short-term jobs that would go along with building a **pipeline** , but it has missed the bigger picture, to the detriment of the American people.

It is incumbent on our Canadian leaders to make sure the mistakes of American politicians don't harm our own interests. They must make the U.S. government understand that, as Natural Resources Minister Herb Dhaliwal has suggested, Canada is prepared to block the **Alaska** Highway **pipeline** from crossing Canadian territory unless the Americans back away from the Senate's prejudicial amendments.

At the same time, they must streamline the regulatory process to allow the **Mackenzie** project to go forward as quickly as possible, and sell the Americans on the benefits of co-operating on the over-the-top option. Such an approach would protect Canada's economic interests while promoting the best solution for everyone involved.

Financial Post: News
Our gas is good as domestic, U.S. says: Ipsos-Reid poll: Americans happy to cut dependence on Mideast energy
Claudia Cattaneo, Calgary Bureau Chief

05/08/2002
National Post
National
Page FP4
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CALGARY - Americans do not regard Canadian energy supplies as "foreign" and they would be willing to pay more for Canadian gasoline if it meant reducing dependence on the Middle East, a Ipsos-Reid poll has found.

The results are being released in Washington today as part of a presentation by the Canadian Association of Petroleum Producers.

"What we see clearly is that Americans look at Canadians as a potentially friendly supply of energy," Tim Moro, vice-president of the energy division of Ipso-Reid, said yesterday.

"Elsewhere, they look in the world they see a reflection of something different and they are very concerned about that right now. They are looking for safety, for security and

Canadians look an awful lot like them."

According to the poll, 85% of Americans say reducing energy dependence on foreign suppliers is important to national security -- but 71% said they do not view Canadian supplies as foreign.

Most Americans are also concerned the U.S. doesn't have enough energy resources and they could be personally affected by shortages of gasoline, electricity and natural gas. The results highlight that American attitudes toward Canada on energy issues are different from general American views toward this country.

According to another, broader public opinion survey by Ipsos-Read also released this week, Canadians embrace their southern neighbour as their closest friend and trading partner, Americans dismiss Canada as almost irrelevant in economics and foreign policy, while underestimating its importance as a trading partner.

Mr. Moro said Canadians can turn those American attitudes into an advantage in the energy business.

"Americans simply assume that Canadians are really no different than people in Oregon. From a business perspective, for energy, that becomes extremely positive, because they see us as people they can do business with. They see us as people they can trust, they see us as people just like them," he said.

Ironically, Canadians are not as eager to co-operate with Americans on energy issues.

In fact, 80% of Canadians polled said they are concerned about foreign ownership of Canadian energy resources, while seven-in-10 Canadians disagree with the statement, "Canadians have nothing to worry about if we supply to the United States."

The energy survey, based on interviews late last fall with 2,001 Americans and 1,001 Canadians, is accurate within 2.2% for the U.S. results, and 3.1% for the Canadian results, 19 times out of 20.

CAPP will highlight the findings in talks with politicians and government officials in Washington over the next two days to raise awareness of energy opportunities in Canada.

Pierre Alvarez, president of CAPP, said those opportunities remain poorly understood in the U.S.

The energy survey is being released against a backdrop of simmering tension on the energy front between Canada and the U.S. over proposed subsidies to support development of a large natural gas **pipeline** from **Alaska** to feed U.S. energy consumers that could undermine a rival project in Canada's **Mackenzie** Delta and disrupt natural gas markets. The proposal is part of a sweeping U.S. energy bill aimed at raising North American energy supplies to reduce dependence on Middle East oil.

"One of the things we hope to get in Washington is a better understanding of the thinking behind the measures, what the likelihood of it proceeding through the Congressional

system is, where the Administration fits on some of these issues," Mr. Alvarez said.

Meanwhile, Harry Longwell, Exxon Mobil Corp. executive vice-president, said yesterday he favours a proposed **Mackenzie** Valley **pipeline** to carry natural gas over one along the **Alaska** Highway.

"That's the one I'm more optimistic about," Mr. Longwell said. "We're moving forward. We'll probably start some advanced engineering work in a year or so, assuming we can get co-operation and positive signals from the folks along the right of way."

Exxon Mobil has gas properties in **Alaska** and Canada's **Mackenzie** River delta. The **Mackenzie** Delta **pipeline** would be owned by Exxon Mobil, Conoco Inc. and Royal Dutch/Shell Group. Canadian natives would hold a one-third stake in the line.

Financial Post: News
Politicians and gas just don't mix: Subsidies threaten to derail gas markets profoundly
Diane Francis

05/07/2002
National Post
National
Page FP3
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In the post 9-11 world, energy is no longer about freeing markets and deregulation in Washington. Now it's billed as a national security issue.

Energy is why George W. Bush, the U.S. President, spent a couple of weekends recently at his ranch with Saudi Arabia's Prince Abdullah and Russian President Vladimir Putin. They weren't just riding horses and eating barbecue. They were talking oil exports and how to slake America's thirst for petroleum.

But an equally important part of the energy equation involves natural gas and has nothing to do with Middle East politics or Russian economic aspirations. It is about politics in Canada and the United States. And there is much at stake for Canada in all of this.

Last week, the U.S. Senate proposed a major departure from U.S. energy policy to underscore the shift in emphasis. Senators agreed to subsidize the building of a natural gas **pipeline** from **Alaska** to the lower 48 states by guaranteeing a floor price.

If approved by the House of Representatives and the President, this will begin to unravel decades of deregulation and the freeing up of markets. This will, in turn, have negative consequences for certain regions in both countries and most certainly for consumers.

Significantly, a prominent group from Mr. Bush's state of Texas has come out swinging. Its members believes the subsidies would decrease gas production elsewhere in North America and increase consumer prices in the long run.

"The point is that supply and demand are in exceedingly delicate balance for this most volatile of all commodities," wrote the Texas Independent Producers and Royal Owners Association. "Sudden government action that skews investment decisions among regions could be disastrous."

They say subsidies will insure the construction of the **Alaska pipeline** and remove incentives for drilling in other regions both in the United States and Canada.

(Canada has huge amounts of gas in Alberta, British Columbia and off Nova Scotia's coast.)

The construction of an **Alaska** line is not new. It was proposed in the mid-1980s until deregulation and disastrously low gas prices nixed the deal. Then, as now, the line will transport huge amounts of natural gas from the prolific fields of North Slope **Alaska** . The gas has been produced with the oil for two decades now, but reinjected underground for storage purposes.

The **pipeline** would be built through Yukon and Alberta and Canada would benefit by an estimated $31.4-billion over two decades in terms of spinoff benefits from construction and operations.

But there are two problems. First of all, subsidies may nix the construction of another **pipeline** to tap the treasure trove of gas in the **Mackenzie** Delta in the Northwest Territories. The benefits of that line going ahead is an estimated $77-billion for Canada.

But if the Americans subsidize, a precious and valuable resource in Canada's north will remain unexploited and unexploitable until the gas in **Alaska** runs out. Alternatively, their subsidies may beget subsidies here to launch the **Mackenzie** project. Producers from other regions may eventually have to be subsidized too.

That would be unfortunate because the current free market has not cost taxpayers anything and has worked very well.

Until 1984, Canada's gas was sold to Canadians for significantly less than the export price charged to Americans. Alberta lobbied fiercely for this to change and the Mulroney government took the wraps off prices and deregulated gas markets. Ever since, an explosion of **pipeline** construction and exploration occurred in Canada to serve the U.S. market. The result is that Canada has more than twice as much of the U.S. gas market as it did in 1984.

Everyone has won from this system. U.S. consumers getting reasonable energy and Canadian producers were no longer sandbagged from competing in the United States by having to charge an artificially high export price.

Now politics threatens to derail what has worked in the past and would change the sector

profoundly. Petro-Canada's CEO Ron Brenneman slammed the Senate for its proposal last week, but rightly announced he was hedging his company's bets by obtaining leases to drill in **Alaska** . Others, notably Imperial Oil Ltd., believe there is room for both **pipeline** proposals. It is the lead producer for the **Mackenzie** Delta project even though its parent, ExxonMobil, is the lead producer in **Alaska** .

However, in the corridors of power there will be, for all intents and purposes, two competing projects, and competing interests. Unfortunately, as the continent's energy sector is carved up, what's needed on this side of the border won't be available: A federal government with vision and direction to avert damage and maximize benefits to Canadians.

Black & White Photo: Pablo Martinez Monsivais, The Associated Press / George Bush and Prince Abdullah weren't just eating barbeque.

Financial Post
U.S. energy firms join fight against Senate bill: 'Canadians are asleep': Subsidies would damage exploration, Mackenzie pipeline
Tony Seskus and Claudia Cattaneo

05/07/2002
National Post
National
Page FP1 / Front
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CALGARY - The Canadian government needs to wake up and defend a free market for natural gas with the United States, or risk being shut out of the biggest energy project on the continent, representatives of U.S. companies with interests in Canada warned yesterday.

" **Alaska** thinks that Canadians are asleep on these things," said Forrest Hogland, chief executive of Houston-based Arctic Resources Co. "[Ottawa] should make sure they are part of this process. We are entering a very, very definite conflicting stage. It's going to be the **Alaska** interests versus the Canadian interests."

Mr. Hogland was one of several U.S. energy executives yesterday who called on the Canadian government to become more vocal in opposing controversial legislation passed recently by the U.S. Senate that would subsidize an **Alaska** Highway **pipeline** through loans and by creating a floor price for natural gas. They said the bill would have far-reaching implications for Canada's energy industry, including stalling exploration in the Northwest Territories and construction of a competing **pipeline** project in Canada's **Mackenzie** Delta.

The Canadian Association of Petroleum Producers is in Washington D.C. this week to

meet with legislators about the bill, which it worries would interfere with the free market.

Mr. Hogland said Alaskans have been able to press forward on their preferred option -- a **pipeline** down the **Alaska** Highway -- largely because there has been little opposition from Canadians.

Mr. Hogland's group has proposed a US$7.8-billion plan to build a **pipeline** to connect **Alaska** and Canadian gas reserves (it would run from Prudhoe Bay to Tuktoyaktuk) and then move gas to Alberta along the **Mackenzie** Delta. The project does not require subsidies.

"Our federal government has certainly taken a neutral stance, saying, 'Let's let market forces determine which **pipeline** should go ahead,' " said John Richels, president and chief executive of Devon Canada Corp., who also disagrees with the **Alaska** subsidies.

"When you are putting a subsidy on one side of it, you are not letting market forces determine that any more. And I would encourage the federal government to take a stance on this," he said.

The subsidiary of Oklahoma City-based Devon Energy Corp. is one of Canada's top producers of natural gas since its takeover last fall of Anderson Exploration Ltd.

The bill, which includes sweeping energy reforms aimed at boosting U.S. domestic sources of energy, is working its way through the U.S. Congress. The proposed floor price on natural gas would making the proposed **Alaska** Highway **pipeline** economically viable.

"Our position is let the free market enterprise decide which one actually goes in," echoed Mark Ellis, president of Burlington Resources Canada Energy Ltd., a unit of Houston-based Burlington Resources Inc. with interests in the **Mackenzie** Delta.

"We probably would like to see the [Ottawa] take a little stronger position, one way or the other, on what they'd like to do," said Nadine Barber, spokeswoman for Anadarko Canada Corp., a unit of Houston-based Anadarko Petroleum Corp., which has interests in both **Alaska** and the **Mackenzie** Delta.

Stephen Kakfwi, Premier of the Northwest Territories, repeated warnings that the subsidy issue is not a distant threat.

"It's not procrastination that is required here, but leadership," he said after speaking to business leaders in Calgary yesterday.

Murray Smith, Alberta's Minister of Energy, goes to Washington D.C. today as part of the CAPP delegation. He believes the subsidies issue remains largely a "hypothetical" concern because the bill is still in the political process.

Report on Business: Canadian

NWT urges action on U.S. gas subsidies Premier warns of threat to Mackenzie Delta pipeline project, economic benefits

LILY NGUYEN

05/07/2002
The Globe and Mail
Metro
Page B8
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CALGARY -- NWT Premier Stephen Kakfwi urged Ottawa to act quickly to prevent U.S. subsidies to Alaskan natural gas, warning they could spell the end of the **Mackenzie** Delta gas project and the billions in benefits expected to go with it.

"The subsidy for Alaskan gas, I believe, will strand Canadian gas," the Northwest Territories leader and major booster of a **Mackenzie** Delta gas **pipeline** said during a speech to the Calgary Chamber of Commerce yesterday. "I believe the subsidy will dry up money invested in exploration in the **Mackenzie** Delta -- over a billion dollars. I believe it will distort the energy market for years to come.

An energy bill passed by the U.S. Senate late last month contains billions in loan guarantees and tax breaks to a proposed $17-billion (U.S.) **Alaska pipeline** that would bypass the NWT.

"The Canadian government has to take note, assess this very quickly and respond; respond with some action that would tell the American government that their good neighbours and good friends to the north of them are feeling a bit slighted, a bit undermined, and ignored.

"It speaks to whether we have a free-trade agreement intact any more or is it just free trade when the Americans decide it's free trade."

Mr. Kakfwi, who discarded prepared speaking notes to make his vehement plea for action from the federal government, refused to prescribe specific measures to Ottawa. Speaking to reporters afterward, however, he noted a proposed **pipeline** to connect Alaskan gas would have to cross Canadian territory, which would require the permission of Canadian regulators.

"I think there's tremendous levers to use," he said.

The U.S. energy bill opened up another front in the trade war blossoming between Canada and the United States.

The federal government has responded with some sabre-rattling, with federal Natural Resources minister Herb Dhaliwal implying last week that Ottawa could delay any southbound U.S. **pipeline** from **Alaska** .

But Mr. Kakfwi said the message needs to be brought across much more clearly.

"The Americans so far seem rather oblivious to this. It's our job to go to [the U.S.] Congress and to let the American legislators know as well that what they do impacts on us," he said. He said he is not interested in federal subsidies similar to the ones being proposed for an **Alaska pipeline** .

A **Mackenzie** Delta **pipeline** from the NWT is considered to be competing against the **Alaska pipeline** from Prudhoe Bay to be the first to connect Arctic gas.

Industry watchers, including Mr. Kakfwi, have argued that the much larger volumes expected out of **Alaska** will flood the market and render supplies from the NWT unnecessary if **Alaska** gas comes onstream first.

But the future of the **Mackenzie** Delta project had looked increasingly secure up until the passing of the U.S. Senate's energy bill, as **Mackenzie** Delta producers announced they would proceed with their project while their Alaskan counterparts announced they could not find an economic way to get gas to market.

Financial Post: Canada
Oilpatch straddling Alaska divide: U.S. tax credit for proposed pipeline could have huge implications for sector: 'Trying to spread our bets'
Claudia Cattaneo and Tony Seskus

05/06/2002
National Post
National
Page FP5
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CALGARY - Barely a day after Ron Brenneman, chief executive of Petro-Canada, took shots at U.S. legislators for backing proposed subsidies to support construction of an **Alaska** Highway **pipeline** , his company scooped up some major leases in **Alaska** , just in case.

"We are just trying to spread our bets a little bit," Mr. Brenneman, whose company is also one of the largest explorer in the **Mackenzie** Delta, said to reporters last week after slamming the U.S. Senate for interfering in North America's free natural gas market.

While Petro-Canada's two-sided strategy is understandable, given **Alaska** 's huge upside as a major natural gas producing region if a **pipeline** is built, it highlights what may be in store for a rival basin in Canada's **Mackenzie** Delta and maybe even other gas-producing

regions across North America.

Under a Senate proposal now being discussed with members of the House of Representatives, **Alaska** gas reserve owners would get a tax credit if the supply they shipped in the **pipeline** fell below US$3.25 per thousand cubic feet, essentially creating a floor price.

"The subsidy ... will attract capital that would go to Canada or Texas and cause that capital to go to **Alaska** instead, thus increasing activity in **Alaska** and decreasing activity in Canada and Texas," said A. Scott Anderson, executive vice-president of the Texas Independent Producers and Royalty Owners Association.

The group, which represents major U.S. independents, many with operations in Canada, echoes concerns expressed by parties in Canada, particularly Stephen Kakfwi, Premier of the Northwest Territories, who fears the **Alaska** subsidies could derail development of his region's reserves.

Yet, for the most part, the Canadian fallout of a subsidized **Alaska** Highway route has been underappreciated in Washington, where the proposed legislation is expected to be rammed through this year to appease **Alaska** , after oil drilling in the Arctic National Wildlife Refuge (ANWR) failed to get U.S. Senate support.

The implications of the **Alaska** project going forward with U.S. government help could be huge for Canada, Northern territorial governments, energy producers, natural gas markets and consumers.

And though Spencer Abraham, U.S. Energy Secretary, tried to allay Canadian fears at a meeting of G8 energy ministers on Friday by stating that the administration was firmly against the subsidies, there are still industry insiders who warn there is reason to remain concerned.

Observers on Capitol Hill, including the Cato Institute, a conservative think-tank, believe that George Bush, the U.S. President, would be reluctant to veto the long-awaited bill because his administration badly wants an energy plan to boost domestic energy sources.

Probably the biggest casualty of U.S. subsidized gas is the Northwest Territories, where the **Mackenzie** Delta's reserves are located and where plans are under way to build a **pipeline** in competition with the **Alaska** project.

Mr. Kakfwi said recently he fears the volume of subsidized **Alaska** gas "is going to be such that there is going to be no benefit to explore for any more gas. We are just going to shut down the industry in the Northwest Territories."

Recognizing that possibility, Herb Dhaliwal, Canada's Energy Minister, said Canada would re-think its neutral stance if the U.S. subsidies, which have now moved to the penultimate committee stage, go ahead.

"They tend to forget that if they want the Alaska route, two-thirds of it is going to have to come through Canada. So they should keep that in mind. At the end, it needs Canadian

support."

Still, Imperial Oil Ltd., which leads a group of producers behind developing the **Mackenzie** fields, remains optimistic a **pipeline** project is economic and is getting ready to file regulatory applications next year.

But others aren't as sure. Tim Faithfull, for example, chief executive of Shell Canada Ltd. and a member of the **Mackenzie** producer group, said development of the **Mackenzie** Delta would have to take into account what happens to the **Alaska** project.

The Canadian economy would also benefit less from an **Alaska** proposal than from a **Mackenzie** Delta proposal.

The Yukon government, a supporter of the **Alaska** Highway proposal because the **pipeline** would be built across its territory, resulting in major economic spinoffs, estimates over the next 24 years the **pipeline** from **Alaska** 's North Slope to facilities in Alberta could add $31.4-billion to Canada's GDP.

The Northwest Territories, on the other hand, estimates a **Mackenzie pipeline** would pump $77-billion into the Canadian economy, over a longer period.

The impact for major energy companies is less clear cut. Recognizing that there is uncertainty over which route will go first, many have protected themselves with interests on both sides.

Petro-Canada bid $8.5-million for leases covering more than one million acres in the southern part of **Alaska** 's North Slope, building on 283,000 acres acquired in the same area last year, according to the **Alaska** Division of Oil and Gas.

Petro-Canada recently announced a major find in the **Mackenzie** Delta with partner Devon Energy Corp. with recoverable reserves estimated at 200 billion to 300 billion cubic feet.

Imperial Oil's agenda is also seen as being linked to that of its parent, ExxonMobil. While Imperial is the major owner of proved reserves in the **Mackenzie** , ExxonMobil has large reserves in **Alaska** .

As well, Conoco Inc. and its merger partner, Phillips Petroleum Co., have stakes on both sides.

Another big loser from the subsidies is expected to be the market. Mr. Brenneman, for example, said subsidized **Alaska** gas would interfere with what has been a free market for about two decades.

The Texas Independent Producers and Royalty Owners Association believes the subsidies would result in a decrease of gas production in other regions of the United States and Canada and that consumers will pay the price for such a distortion of market signals.

"The point is that supply and demand are in exceedingly delicate balance for this most volatile of all commodities," the group wrote to Tom Daschle, U.S. Senate Majority

Leader. "Sudden government action that skews investment decisions among regions could be disastrous."

Murray Smith, Energy Minister for Alberta, shares many of the same concerns and will be in Washington this week to argue against government interference in the North American energy market.

Which **pipeline** will be built and whether it will involve subsidies will be decided in the coming months.

Meanwhile, says Stephen Clarkson, a trade expert at the University of Toronto, hold on for a bumpy ride.

"Canada has very few bargaining chips," he said. "You can't say, 'You're being nasty to us on lumber, therefore you should be nice to us on energy.' It's completely different spheres."

Black & White Photo: Jeff Mcintosh, The Canadian Press / Ron Brenneman is chief executive of Petro-Canada, which is exploring in the **Mackenzie** Delta. The **Alaska** Highway and **Mackenzie** projects are trying to be first to market with a **pipeline** .

Financial Post
The Big Picture
Catfish swim into sights of U.S. trade 'police': Bush talks the talk but snubs partners
Peter Morton

05/06/2002
National Post
National
Page FP1 / Front
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WASHINGTON - While the Republicans have their symbol, an elephant, and the Democrats have theirs, a donkey, the symbol that may soon be given the administration of George W. Bush, the President, and Congress could be the catfish.

Lobbied heavily by the Catfish Farmers of America, the U.S. Senate quietly slipped in an amendment to the huge farm bill weeks ago that would essentially try to ban the importation of Vietnamese catfish because it was undercutting the southern U.S. catfish market.

This comes just after the Bush administration, touting its new pro-free trade agenda, signed a free trade deal with Vietnam.

"This flies in the face of what they thought they were getting with the U.S. opening up its markets," Frances Zwenig, a trade expert with the U.S.-ASEAN Business Council, complained to reporters recently.

The Vietnamese catfish imbroglio has become the latest example of how the Bush administration talks the talk about free trade but, at least from the perspective of its trading partners, is hardly doing the walk.

At the top of a growing list of trade disputes is the move last week to slap duties of 27% on Canadian softwood lumber. That long-simmering battle, which is far from over, stems from U.S. lumber industry complaints about what it calls illegal and unfair subsidies by the four major timber producing provinces -- British Columbia, Quebec, Ontario and Alberta -- to grab market share in the United States.

The U.S. administration is again gearing up for another battle over Canadian wheat and its determined this time to break down the monopoly of the Canadian Wheat Board, something it has had little success doing. And now Congress has approved an energy bill that would not only demand that a natural gas **pipeline** from the far north go through **Alaska** but create a floor price of US$3.50 per thousand cubic feet for gas to ensure the **pipeline** is built.

If gas prices fall below that, the **pipeline** promoters get tax credits.

"I made it pretty clear to the Americans that they can pass all the amendments they want on the energy bill, but two-thirds of [an Alaskan] **pipeline** will go through Canada," said Herb Dhaliwal, the Minister of Natural Resources, at a meeting of international energy ministers this week in Detroit. "First of all, we will not let our gas be stranded in the North due to large subsidies that come out in the U.S."

This administration is not limiting its trade disputes to its largest trading partner, either.

It has also locked horns with the European Union, Japan, Russia and South Korea by slapping steel imports from those countries with duties of up to 30%. Canada and Mexico were exempted.

The EU and Japan are threatening to retaliate by imposing duties on American-made goods such as clothing, guns, pens, furniture, fire engines, yachts and steel.

The administration also angered Pakistan, a key ally in its war against terrorism, by refusing to give the textile producing nation an exemption on textile quotas because of lobbying from the textile producing states of North and South Carolina.

But most of those trade disputes pale to the proposed farm bills that would crank subsidies to American farmers by as much as US$73.5-billion to US$170-billion over the next 10 years. Both the House of Representatives and the Senate have approved bills that must be consolidated before they are sent to Mr. Bush for signing into law.

Besides the direct cash subsidies to farmers, major exporting countries such as Canada could be dramatically affected over a proposal to insist on labelling of country of origin

on all food products, including beef. The worry is that U.S. consumers might be driven away from anything other than U.S.-origin beef and meat products.

Ottawa has been trying to crank up the pressure on the administration, Congress and even the U.S. public.

"The meaning of free trade should be just that -- free trade -- not a la carte free trade where the rules change unilaterally when one or other of the [NAFTA] partners temporarily lose market share," Michael Kergin's, Canada's ambassador to the United States, told a New Jersey trade conference last week.

Yet the U.S. perspective, it appears, is much different.

In a speech on the same day, Robert Zoellick, the U.S. Trade Representative, told a group of Arizona business writers that too much focus is put on current trade disputes and that "such disputes are relatively insignificant to the economy in the long run."

Mr. Zoellick insists the Bush administration has launched a renewed trade initiative in the wake of the failure of the Seattle launch of talks two years ago.

And he acknowledges something that is obvious -- the United States is the world's richest economy that everyone wants a piece of. The U.S. imports about US$1-trillion a year in goods.

"We want to keep U.S. markets open and even open them further," he said. "To do so, we have to give American businesses and farmers a fair chance to compete."

And while he talks long about the U.S. trade strategy, he is also the first admit there are times "when we need to zigzag with Congress to keep moving ahead."

Such zigzagging includes paying heed to Senator Max Baucus, chairman of the powerful Senate finance committee who holds the key to Mr. Bush getting his badly needed Trade Promotion Authority to negotiate new free trade deals. Mr. Baucus, a senator from Montana, takes the Canadian softwood and wheat issues very seriously.

"The point here is that Canada needs to recognize that on any of these issues, at the end, U.S. domestic politics is going to dictate U.S. positions," says Bill Merkin, a veteran Washington trade consultant and former U.S. trade negotiator.

He said on key issues like steel and agriculture, the domestic lobby groups have considerable leverage over Congress. And that is especially true this year with the looming fall election.

"The administration needs the goodwill of Congress and over there, everyone faces an election eventually," he says.

Black & White Photo: Kimimasa Mayama, Reuters / Robert Zoellick, the U.S. Trade Representative, says too much focus is being put on current disputes.

Financial Post
Contentious gas subsidies may still pass: Alaska pipeline : Experts warn, even as White House offers assurances
Tony Seskus and Claudia Cattaneo

05/04/2002
National Post
Toronto / Late
Page FP1 / Front
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CALGARY - A controversial U.S. energy bill that proposes gas subsidies for an **Alaska** Highway **pipeline** could still pass, say experts in Washington and **Alaska** , despite assurances yesterday from the U.S. Energy Secretary that the Bush administration would prefer a market solution to Arctic development.

The bill, which is working its way through the U.S. Congress, would create a floor price on gas shipped from **Alaska** , making the proposed **Alaska** Highway **pipeline** route economically viable. Under the plan, energy producers would also receive loan guarantees to build the **pipeline** .

Canadian gas producers have opposed the bill, as has Herb Dhaliwal, Canada's Minister of Natural Resources, saying it could derail any plans for Canadian **pipeline** routes and disrupt the natural gas market.

Yesterday, Spencer Abraham, the U.S. Energy Secretary, said the White House has been "very clear in terms of the tax provisions we support, which were not the ones ... with respect to that subsidy.

"The administration's position is a neutral one with respect to route preference. We believe the market should make that decision," Mr. Abraham told reporters after a meeting of the G-8 energy ministers in Detroit.

However, many observers still expect the bill to pass, in part because the Bush administration needs a sweeping energy bill, and in part because this one has received broad support in Congress.

"If [Canada] brought this to a higher plain by direct engagement with [George W. Bush], perhaps the administration might consider threatening vetos, but I doubt it," said Jerry Taylor, director of natural resource studies at the Cato Institute, a conservative think-tank in Washington, D.C.

The bill, passed in the U.S. Senate last week, includes broad measures to boost domestic energy sources. It still must be merged with a separate bill passed by the House of Representatives.

"Since both the House and Senate have weighed in on that particular **pipeline** project I suspect that it will [be approved]," said Bob King, spokesman for Tony Knowles, the Governor of **Alaska** .

"There was broad, bi-partisan support, at least in the Senate, for that specific provision. There is also support on the House side for similar incentives. At the end of the day [critics] will realize that these types of provisions and incentives will be good for meeting the nation's energy needs."

The Canadian Association of Petroleum Producers has said it is "troubled" by the bill, which is seen by many as threatening the viability of a competing project in Canada's **Mackenzie** Delta.

"We are troubled by any signs that governments want to get back into the marketplace," Mr. Alvarez said last week. "Ultimately, it comes down to a belief that the market is the one that should determine the nature, scale and pace of projects."

Some opposition to the bill is already coming from U.S. producers -- many of which now have Canadian operations -- which see the subsidies as favouring development of **Alaska** resources at the expense of Canada and U.S. regions such as Texas.

"We have urged [Senate Majority Leader Tom] Daschle and others to be very cautious about what they are doing," said Scott Anderson, executive vice-president for the Austin-based Texas Independent Producers and Royalty Owners Association.

"It seems quite likely that a measure like this would skew investment decisions toward **Alaska** and away from Canada and the lower 48 States in the U.S.

"Even though that might temporarily create a gas bubble, an increase in supply of gas from **Alaska** , before long there would be a day of reckoning for consumers and it's very likely this policy would exacerbate price volatility," Mr. Anderson said.

Under the proposal, such **Alaska** producers as ExxonMobil Corp., BP PLC and Phillips Petroleum would get the subsidy if prices fall below US$3.25 per thousand cubic feet. It also proposes US$10-billion in project loan guarantees.

"They tend to forget that if they want the **Alaska** route," said Mr. Dhaliwal, "two-thirds of it is going to have to come through Canada. So they should keep that in mind. At the end, it needs Canadian support."

BUSINESS

Yukon, Territories on opposite sides of pipeline proposal

05/06/2002
Kitchener-Waterloo Record
Final
Page D8
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VANCOUVER -- The Yukon and Northwest Territories are lining up on opposite sides of the fence in a brewing dispute over northern gas **pipeline** developments.

The U.S. Senate recently passed a bill that -- if it becomes law -- would guarantee a floor price for natural gas carried by an **Alaska** Highway **pipeline** , which would run from **Alaska** 's North Slope, across the Yukon and into Alberta.

The bill grants a tax credit for all gas shipped through the **pipeline** that sells at a price lower than $3.25 US a thousand cubic feet.

But the bill also ensure the **pipeline** runs through the Yukon, not the Northwest Territories, another route option for a **pipeline** .

Northwest Territories Premier Stephen Kakfwi has denounced that action as an unfair subsidy to U.S. producers.

His territory's proposed **pipeline** would run from the Canadian gas fields of the **Mackenzie** Delta down the **Mackenzie** River.

"In the Northwest Territories, we think it's going to completely wipe out the exploration

commitments made," Kakfwi said in a weekend interview.

"(U.S. officials) are assuming they can just build an (**Alaska** Highway) **pipeline** right through Canadian territory and subsidize the pipe and strand Canadian gas for two decades or more," he said.

Some analysts have agreed the proposed U.S. regulation could set back the N.W.T. **pipeline** project, which could also benefit Canadian gas resources.

In a prepared speech delivered in Vancouver on Friday, Kakfwi argued the federal government should "forcefully express its opposition at the highest levels to these measures being proposed in **Alaska** and the U.S. Senate initiatives."

Federal Natural Resources Minister Herb Dhaliwal seemed to support this position last week when he implied Ottawa could delay any southbound U.S. **pipeline** forced to cut through Canadian soil.

He told reporters Ottawa would not allow Canadian gas to be remain untapped due to U.S. subsidies.

But the Yukon government supports the proposed U.S. bill, said Scott Kent, minister for energy, mines and resources.

The Yukon government maintains there is room enough in the natural gas industry for two northern pipelines.

Sam Harrel/News-Miner

and foreman Dave Lanni guide a load of rip-rap into the washed-
on of Chena Pump Road and Chena Small Tracts. Snowmelt and
itersection and began eroding the shoulders of the roadway.

,ep busy

ı storm knocks down
power. Page B-1

g the shoulders. Flood
ıes are in effect for five
creeks as rain and melt-
hoke frozen waterways.
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alled off a heavy snow
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logist with the National
ngaas blamed the unsea-
v and rain showers on a
ems to have lost its way
rth, he said. In the last
ee inches of rain has fall-
r ned with melting
, is causing the

See FLOODING, Page A8



Sam Harrel/News-Miner

Fairbanks I Tow driver Vickie Doggett hooks a chain to a Jeep Cherokee that went off the edge of the road Wednesday morning at the intersection of Chena Pump Road and Chena Small Tracts. Janet Meehan lost control of her Jeep in water overflowing from Cripple Creek.

in works for late May

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ed in March that it would
work force because it was
s coal contract with South
of the mine's production,
ıs a year, goes to South
Railroad moves the coal to
e it is shipped overseas.
ompany had been trying to
contract with the South
end of last year.
pe that the South Koreans could renew the contract, said Steve Denton, Usibelli Coal Mine's general manager. And if the South Koreans opt to make short-term purchases on the spot market, Usibelli could compete for those sales, he said.

But with layoffs a large undertaking, the company believed it had no choice but to move ahead with the plan, Denton said.

"We're working with the people to try to find ways to mitigate the losses," Denton said. Some may take an early retirement option,

See USIBELLI, Page A8

ing years.

The other major tax proposal

Republican Rep. Jim Whitaker,

See LEGISLATURE, Page A8

Young: No ANWR, no energy plan

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By SAM BISHOP
News-Miner Washington Bureau

WASHINGTON—Rep. Don Young said Wednesday he would rather not see an energy bill this year if it excludes oil drilling in the Arctic National Wildlife Refuge.

Young, R-Alaska, will be in an influential position as the Senate and House merge their differing versions of the energy bill. He said he will serve as vice chairman of the conference committee.

He's in no hurry to start or finish the work, though.

"There's no big rush, because the Senate bill doesn't produce any energy," Young said.

The Senate bill provides tax incentives and other provisions to boost construction of a natural gas line from the North Slope, but Young said he has been told by industry officials that the legislation isn't critical to a decision on whether to build.

"A lot of it is unnecessary," he said.

The House bill includes language to open the Arctic National Wildlife Refuge to oil drilling, but the Senate bill does not.

House Republicans on the conference committee are in "lock step" behind ANWR drilling, Young said. But he isn't predicting victory.

"I think it's going to be difficult in conference probably because of the makeup of the Senate conferees," Young said.

The Senate Democratic leadership, which appoints the conferees, is opposed to ANWR development. If the Senate Democratic conferees stand fast against ANWR drilling, "we may not have a bill," Young said.

"If it doesn't produce any energy, why go through the exercise?" he said.

Stopping the bill would not be a problem, Young said. "We have the votes."

See YOUNG, Page A8

Conference committee in limbo

By SAM BISHOP
News-Miner Washington Bureau

WASHINGTON—The Senate is having trouble deciding who will sit on a committee with the House to work out differences between their energy bills.

The Senate legislation carries tax credits for North Slope gas and oil development and authorizes spending on a variety of other Alaska projects. The House bill allows oil drilling in the Arctic National Wildlife Refuge.

A conference committee must pick which elements to keep in a final bill that goes back to both chambers for approval.

Senate Majority Leader

See SENATE, Page A8

ıutting more children in the hospital

y "changes the perspective that obesity is
n problem to really focus on ... child-
as a serious medical problem,"
—Dr. William Dietz

: warned that child-

The new study "changes the perspective that obesity is simply a cosmetic problem to really focus on ... childhood obesity as a

National Medical Center, who has patients as young as 5 with obesity-caused sleep apnea.

The study "represents just the tip of the iceberg," she said—because doctors often don't record obesity on hospital discharge records, so the CDC probably missed many cases. Insurance companies don't pay to treat it until the child comes down with a formal illness, Mirza complained.

About 13 percent of children and ado-



YOUNG: ANWR

Continued from Page A1

House Minority Leader chard Gephardt, D-Mo., said his party wants the bill.

"It's obviously a very important piece of legislation. We need a long-term energy policy for this country, and this is our one opportunity in this Congress to get it, so we take this very seriously, and we're going to work hard to get a good bill," Gephardt said Wednesday.

If House Republicans kill the bill in conference, Young said, the natural gas tax credit, which Alaska GOP Sen. Frank Murkowski secured in the Senate version, could be passed in a different bill.

"It doesn't hurt," Young said of the tax credit, "but I've also been told it isn't necessary to have the gas line built. It makes it more attractive, there's no doubt about that."

Young said it could take until September to reach an agreement in conference. In the meantime, the Senate might be influenced by changes on the world scene, he said.

"I believe very strongly that if we have a dust-up in Iraq or some other area, there's a good possibility the price of gasoline would go quite high, maybe even a shortage of it, and then you'd see a different attitude," Young said.

Deal in works to free Suu Kyi

The Associated Press

YANGON, Myanmar—Opposition and government negotiators are close to a deal that could release pro-democracy leader Aung San Suu Kyi from house arrest, an opposition leader said Thursday.

Tin Oo, the vice chairman of Suu Kyi's party, told reporters that he met her on Wednesday at her lakeside residence where she has been held for the last 19 months.

Tin Oo said Suu Kyi told him to inform the media that "the developments will be seen within days."

Asked if the opposition and Myanmar's military junta are close to an agreement, he said: "It is most feasible. It will come out with an improvement within days." He did not elaborate.

SENATE

Continued from Page A1

Tom Daschle, D-S.D., told reporters Wednesday that his party is still trying to decide which senators should sit on the committee.

"We had seven or eight specific committees that were involved in the creation of the bill," Daschle said. "Those committees clearly have to be represented in some way. And so that's what we have suggested, is that at least in the primary committees of involvement, that the chairs be represented."

That may conflict, though, with an agreement reached on the Senate floor last week.

The Senate, without objection from any members, decided that its conferees on the bill would come from members of the Energy and Natural Resources Committee and the Finance Committee.

Six Democrats and five Republicans were to come from the Energy Committee, while three Democrats and two Republicans were to come from the Finance Committee, according to the Congressional Record.

Daschle hinted Wednesday that Republicans might be [illegible]

[illegible] ed to the conference yet, [illegible] we have not been given [illegible] list," Daschle said. "I talked to Sen. Lott about the conferees this morning."

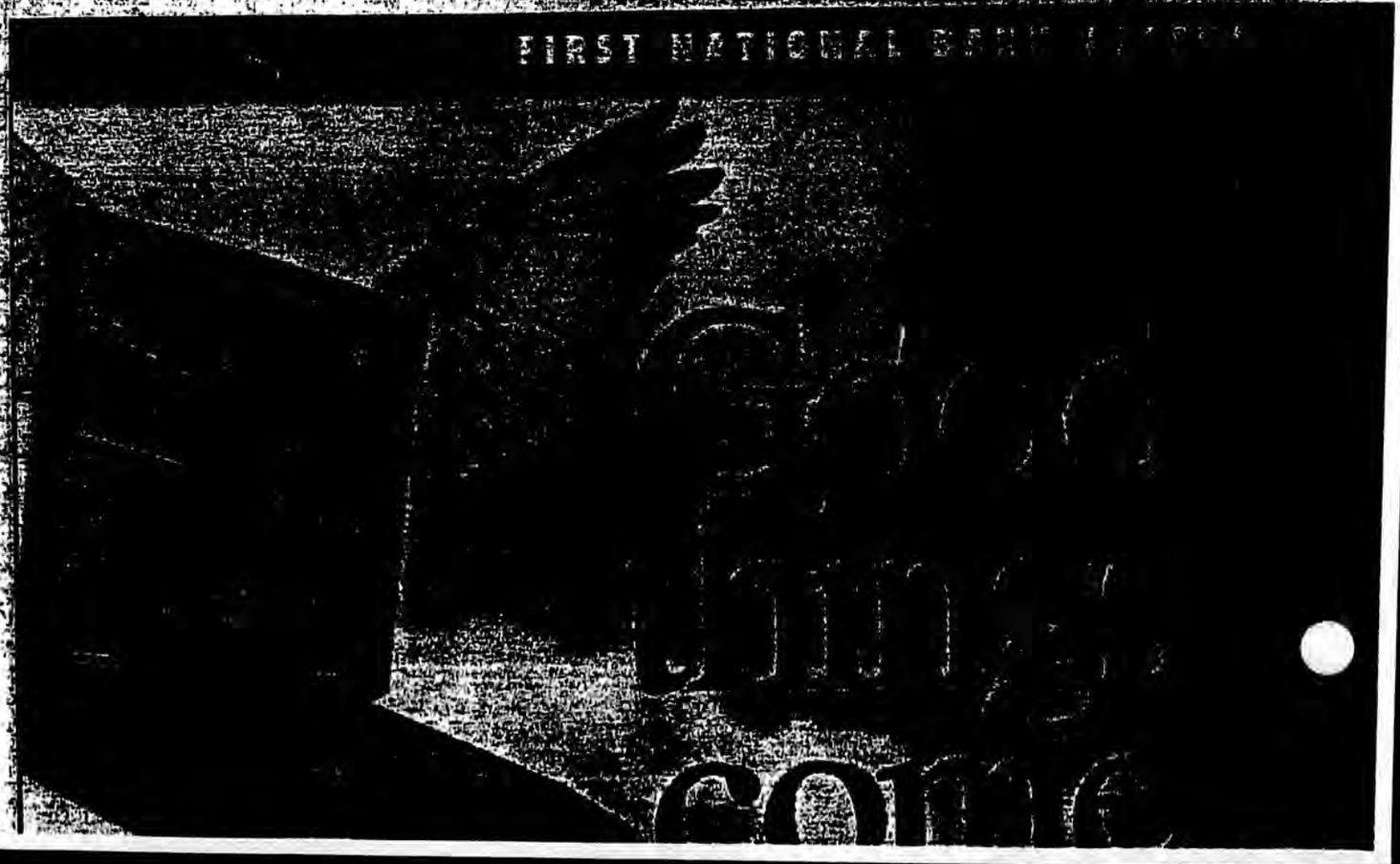
Later in the day, the spokesman for Republicans on the Energy Committee said the list had been delivered.

"We have submitted our list of conferees to the Democrats, and that list is consistent with the unanimous consent that was agreed upon," said Dave Woodruff.

On the House side, where Republicans are in charge, some conference committee members have been selected, but no announcement had been made. That is expected this week.

Rep. Don Young, R-Alaska, said he would be the vice chairman of the House conferees. The chairman will be Rep. Billy Tauzin, R-La. Rep. Joe Barton, R-Texas, will also be a member, Young said.

Democrats are still working on their membership, according to Minority Leader [illegible] Gephardt, D-Mo. "We h[illegible]n't [illegible] Gephardt told [illegible]



SENATE: Committee

Continued from Page A1

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That may conflict, though, with an agreement reached on the Senate floor last week.

The Senate, without objection from any members, decided that its conferees on the bill would come from members of the Energy and Natural Resources Committee and the Finance Committee.

Six Democrats and five Republicans were to come from the Energy Committee, while three Democrats and two ...oublicans were to come from ... Finance Committee, according to the Congressional Record.

Daschle hinted Wednesday that Republicans might be holding up the Senate process as well.

"Well, no one's been appointed to the conference yet, because we have not been given their list," Daschle said. "I talked to Sen. Lott about the conferees this morning."

Later in the day, the spokesman for Republicans on the Energy Committee said the list had been delivered.

"We have submitted our list of conferees to the Democrats, and that list is consistent with the unanimous consent that was agreed upon," said Dave Woodruff.

On the House side, where Republicans are in charge, some conference committee members have been selected, but no announcement had been made. That is expected this week.

Rep. Don Young, R-Alaska, said he would be the vice chairman of the House conferees. The chairman will be Rep. Billy Tauzin, R-La. Rep. Joe Barton, R-Texas, will also be a member, Young said.

Democrats are still working on their membership, according to Minority Leader Richard Gephardt, D-Mo. "We haven't gotten to that," Gephardt told reporters Wednesday.

tourist," he said, before they tried to cross the flooded road. "That area is 300 feet long. It varies in depth. It can change."

Road crews on the Steese Highway reported flooding at several locations between 46 Mile and 80 Mile, Blanning said. Crews also are watching the Steese Highway for breeches in the road surface between Fox and Cleary Summit, he said.

Some road flooding is reported on the Elliott Highway between Livengood and Manley. The remainder of the road is muddy, soft and rutted, and drivers should be cautious, he said.

The Dalton Highway from 90 ...instead of pooling on top, he said.

Officials think the weather should improve by next week, but that's too late for Janet Meehan. Despite using what she considered every caution, she found herself being cut out of her black Jeep Cherokee seat belt. Meehan only suffered some muscle soreness from the accident, despite her icy dip.

As University Fire Chief Mitch Flynn and trooper Andrew Adams helped Meehan from the ambulance after being checked over, an emergency worker said "Have a nice day."

"It's got to get better," Meehan said.

SENATE: Committee

Continued from Page A1

and some job losses may be due to attrition, he said.

Usibelli's problems come from Indonesia and China, where coal is produced cheaply and is close to needy Asian markets. It's a matter of supply and demand, Denton said.

"There are too many suppliers in the world," Denton said.

Denali Borough Mayor John Gonzales predicts the layoffs will trickle down into the community.

"I suppose most will try to find jobs elsewhere, but there are not many other jobs in the community," Gonzales said. Some people are hoping that the Healy Clean Coal plant will be brought into operation and bring jobs back, but that is at least a year off, Gonzales said. Congress has authorized $125 million to retrofit the plant.

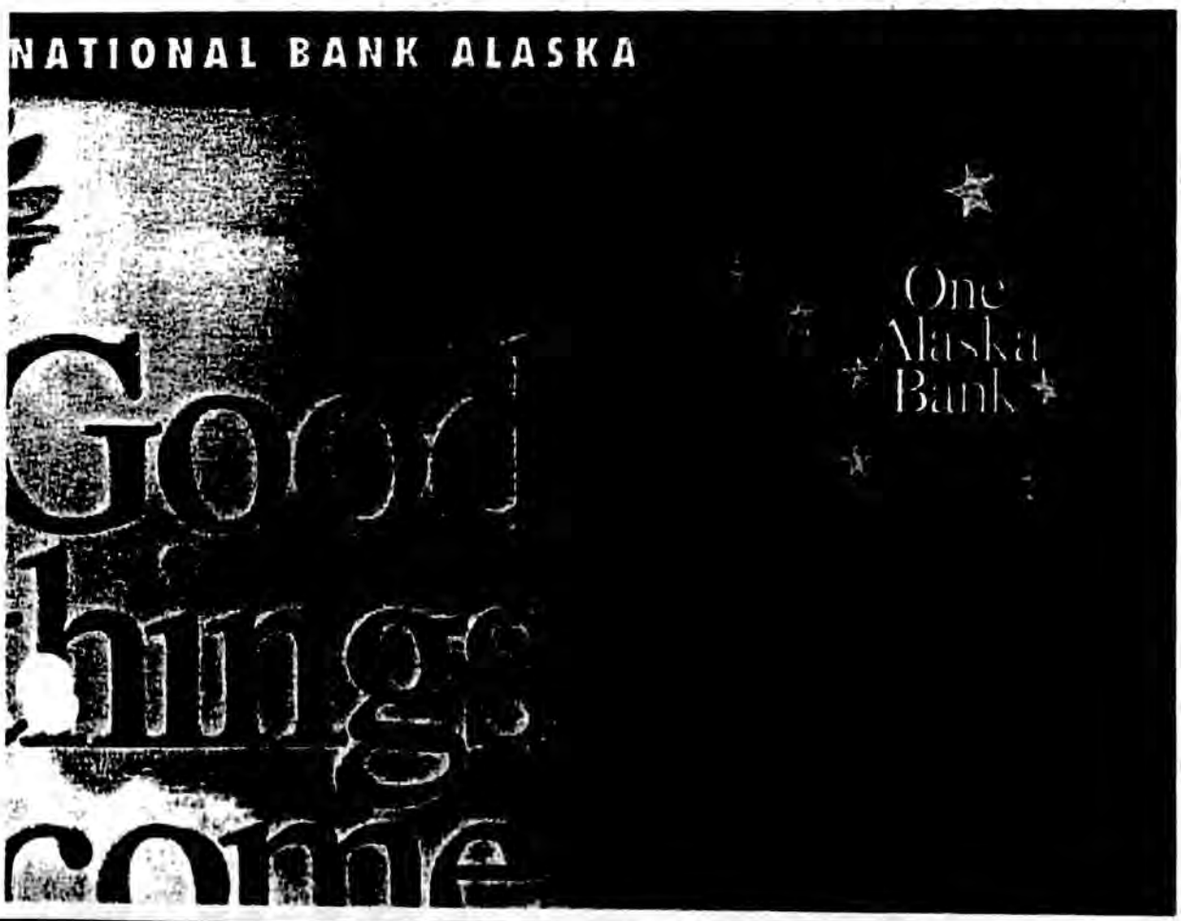
A complete retrofit could provide jobs for 35 to 50 years, said Steve Haagenson, president of Golden Valley Electric Association. GVEA would operate the plant and purchase its power if the plant were retrofitted, he said.

Coal production and its use is also part of President Bush's energy plan, but those things "don't happen overnight," Gonzales said.

Wallace, the chamber president, said there is a certain amount of uncertainty about what will happen in Healy. "Home for sale" fliers are popping up on bulletin boards around town, she said.

"People have been here forever," she said. "There certainly has been some familial support, but we don't know how far that will take everybody.

"We may see some population changes."



OBESE

Continued from Page A1

rie foods.

More children are suffering Type 2 diabetes, a dangerous disease that once struck mostly in middle age. Obesity also can worsen asthma and spark gallbladder disease. People can die

canada.com News

Wednesday • May 1 • 2002

U.S. Senate pipeline plan blasted

Petro-Canada chief warns Canadian gas exports at risk

Chris Varcoe; With files from Grant Robertson, Calgary Herald
Calgary Herald

Wednesday, May 01, 2002

The head of Petro-Canada says a U.S. Senate proposal to assist the construction of an Alaskan natural gas pipeline project could distort North America's finely tuned energy markets.



Calgary Herald
Petro-Canada CEO Ron Brenneman said it's unknown what impact a U.S. proposal to subsidize Alaskan gas would have on a Mackenzie pipeline.

The U.S. Senate passed a controversial energy bill last week that offers $10 billion US in loan guarantees to the Alaska Highway gas pipeline project.

It also includes a contentious provision offering Alaskan producers a guaranteed floor price for their commodity.

If ratified, the bill could put Canadian gas at a distinct disadvantage, Petro-Canada chief executive Ron Brenneman warned Tuesday.

"To me, that represents a form of subsidy," he said after the company's annual meeting.



Calgary Herald

"We (would) have gas coming into -- or through -- a deregulated market that we all compete in that might actually be subsidized by U.S. federal government. So that's a big disappointment to us."

Last week, the U.S. Senate approved an omnibus energy bill that would provide tax credits to Alaskan producers building a northern pipeline, offering them a guaranteed floor price for gas of $3.25 US per thousand cubic feet (mcf).

If gas, which traded near $3.80 US per mcf Tuesday on the New York Mercantile Exchange, rises above $4.80, the tax credits would have to be repaid.

While the bill received bi-partisan support in the U.S. Senate, it must be co-ordinated with a House of Representatives energy bill and then passed by the Bush administration.

Three Alaskan petroleum producers -- BP PLC, ExxonMobil Corp. and Phillips Petroleum Co. -- are now studying construction of a proposed $17-billion US pipeline running along the Alaskan Highway, through the Yukon into northern B.C. and Alberta.



Last month, a BP spokesman said the project wasn't economically viable at current prices and wouldn't proceed until the Prudhoe Bay producers saw a better chance of profit.

A spokesman for Alaskan Gov. Tony Knowles said the bill would reduce the project's price risk and help secure continental energy supply by tapping into

huge northern reserves.

Calgary Herald Petro-Canada chief executive Ron Brenneman says a U.S. Senate bill, if adopted, would amount to subsidizing Alaskan gas.

"I don't think it distorts the marketplace as far as consumers are concerned," Bob King said from Juneau.

"It would be, in essence, a zero-sum game. . . . If prices go up, as they frequently do, those supports would be recouped."

But the announcement has caused an uproar in Canadian energy circles, where a proposal to build a small pipeline from the Northwest Territories to Alberta is under consideration by a group of companies led by Imperial Oil Ltd.

N.W.T. Premier Stephen Kakfwi said last week the American tax amendment is worth up to

$2 million US per day and he's concerned it would strand Mackenzie Delta natural gas for years if the larger Alaskan venture is built first.

In Ottawa, the federal government also complained Tuesday that the U.S. proposal would distort gas markets, which have been deregulated in Canada for more than 15 years.

"It's not consistent with Canadian thinking on the way energy policy should be run," said Tracy Thiessen, a spokeswoman for Natural Resources Canada.

"Our energy policy is based on markets -- open, fair markets. And that isn't changing."

Industry analyst Roland George of energy consultancy Purvin & Gertz Inc. said if the U.S. bill is passed, it would cause petroleum producers to redirect investment away from conventional gas basins -- such as Western Canada -- to Alaska.

While Alaskan companies would receive the subsidized rate if prices drop, as they did last winter, Canadian producers would only collect the lower, deregulated price, George said.

"The floor price subsidy has the potential to have a cataclysmic effect on the market," he said.

"They will flood the market with Alaskan gas and the price for everyone else will go down."

Petro-Canada is one of the country's most aggressive northern explorers.

Last week, Petro-Canada and partner Devon Energy Corp. announced a large gas discovery in the Northwest Territories that contains estimated reserves of up to 300 billion cubic feet.

Petro-Canada could move gas through the proposed Mackenzie Delta pipeline, although Brenneman said it's uncertain what impact the U.S. bill would have on the construction timing or likelihood of the project being built.

"The viability of the Mackenzie Valley pipeline stands on its own," he added. "With or without the Alaskan pipeline, we will see gas moving out of the Mackenzie Delta probably in 10 years time or so."

Petro-Canada's shares rose 79 cents Tuesday on the Toronto Stock Exchange to $42.27.

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PATRICK COUGHLIN WORK ACTIVITY REPORT

MEMORANDUM

TO: Senator John Torgerson
FROM: Patrick Coughlin PJC
SUBJECT: Work Activity Report
DATE: May 14, 2002

O&G BILLS & RESOLUTIONS

Significant Involvement
2001

Act	Sponsor	Description	Status
SB 143	Resources	Amend ROW act for reimbursement of pre-application costs	Senate Pass House Rules
SB156	Resources	Amend AS 38.05 to provide for single best interest finding	Senate Pass House Pass
SB158	Resources	Require a financing report from the DOR commissioner	Senate Pass House Finance
SB164	Senate	Amend ROW act to preclude an OTT route	Senate Pass House Pass
SCR10	Finance	Netricity Resolution	Senate Judiciary House Pass
SCR14	Rules	Joint Committee on Natural Gas Pipelines	Senate Rules House None

2002

SB221	Taylor	AK Gas Development Authority	Senate Resources House None
SB260	Gov	Alaska RR tax-exempt bonding	Senate Resources House None
SB319	Torgerson	Shallow Natural Gas Leasing	Senate Pass House Pass
SB343	Resources	Best Available Technology	Senate Pass House Pass
SB 296	Resources	Alaska Natural Gas Project Act	Senate Pass House Pass
HB 190	Whitaker	Pipeline Incentives	Withdrawn
HB302	Whitaker	Alaska Gas Corporation	Senate Resources House Pass
HB307	Fate	Exploration Incentive Credit	Senate Pass House Pass
HB308	Fate	Discovery Royalty	Senate None House O&G

HB311 Whitaker	Taxes and Leases	Senate None House O&G
HB394 Rokeberg	Royalty Modification	Senate None House O&G
HB410 Oil&Gas	Development Authority	Senate None House O&G
HB423 Gov	Railroad Bonding	Senate None House Finance
HB519 Rule	Natural Gas Pipelines	Senate None House Rules
HB527 Resources	Minto Flats	Senate Pass House Pass
HB530 Rules	Natural Gas Reserve Tax	Senate None House O&G
HJR44 Oil&Gas	Pipeline Route	Senate Pass House Pass

Review and Analyze
2001

SB 17 Governor	Amend Stranded Gas Act to change expiration date	Senate Transportation House None
SB 32 Rules	Amend ROW act to allow renewals every 30 years and reimbursement of operation, maintenance, and operation	See SB 76
SB 76 Wilken	Amend ROW act to allow renewals every 30 years	Senate Pass House Pass
SB 77 Torgerson	Repeal AS 38.05.135(g) re over/under payments	Senate Pass House Pass
SB 121 Leman	Amend ROW act to define "substantial change"	Senate Pass House Pass
SB 125 Halford	Amend AS 38.05.130 to define damages for surface estate	Senate Resources House None
SB 136 Resources	Create resource development board	Senate Finance House None
SB 139 Governor	Water rights	Senate Finance House None
SB 179 Finance	AIDEA bonds for Alaska Intrastate	Senate Resources House Pass
HB 3 Rokeberg	Amend PFD law	Senate Resources House Pass
HB 9 Green	Amend Stranded Gas Act to broaden to include ng and gtl	Senate None House Oil & Gas
HB 21 Porter	Findings about the southern route	Senate None House Oil & Gas
HB 38 Governor	Amend Stranded Gas Act to broaden to	Senate None

	include ng and gtl	House Oil & Gas
HB 83 HOG	Amend ROW act to delcare policy for ngl pipelines and AK hire	Senate None House Oil & Gas
HB 165 Lancaster	Add land to Kenai River Special Management Area	Senate Resources House Pass
HB 190Whitaker	Amend AS 43.58 to add a reserve tax	Senate None House Pass
HB 220Kott	Tax Credits for Marathon	Senate None House Pass
HB 236Finance	AIDEA bonds for Alaska Intrastate	Senate Resources House Pass
HJR 7 Ogan	Open ANWR	Senate Pass House Pass
HCR 8 Whitaker	Oppose the OTT route	Senate Rules House Rules
HJR 13Cissna	Keep 90% in ANWR	Senate None House Finance
HCR 17Rules	Netricity Resolution	See SCR 14

2002

SB308 Therriault	CZMA Phasing	Senate Pass House Pass
SB 310Therriault	Pipeline Coordinator for Gas Line	Senate Resources House None
SB361 Therriault	Comprehensive Permit Coordination/CZMA	Senate State Affairs H O&G
SB371 Resource	Redoubt Shoal/CZMA Amendment	Senate Pass House Pass

Other Projects
2001

- Discuss oil and gas and gas line issues with various House and Senate members as requested
- Review and evaluate Economic Limit Factor
- Review and rrovide advice on the gas line and Oil and Gas budget
- Work on possible Right of Way Bill for a gas line between Fairbanks and Nikiski

Other Projects
2002

- Work on amendments for the federal energy bill
- Work with other experts to assist Senator Torgerson in negotiating changes to the federal energy bill
- Assist with the development of various project economic models
- Assist with the development of evaluation of federal price floor proposal

- Discuss oil and gas and gas line issues with various House and Senate members as requested
- Assist with development of International Committee on Alaska Gas Pipeline Project
- Refine problems for other experts
- Daily monitoring of developments in gas supply and demand lower 48 markets, including information from CERA, EIA, Simmons International, MMS, AkDNR/DOR, other experts, and other agencies
- Daily monitoring of developments in foreign supply markets
- Work on comprehensive gas fiscal system with various experts including Dr. Van Meurs
- Continue review and evaluate Economic Limit Factor and severance tax proposals
- Provide comprehensive analysis of state oil and gas incentives
- Review various fiscal certainty issues
- Review "substantial similarity" issue for Initiative and various legislative proposals
- Review and analyze proposals and information provided by various companies, including the producers, the pipelines, the explorers, other project sponsor, other interested entities
- Work with various governmental agency including the MMS, the FERC, the NEB, Yukon officials
- Draft various proposed bills including:
    - Establishing a North Slope Gas Commercialization Team
    - Evaluation of Div. of Oil & Gas budget bill
    - New gas severance tax
    - Evaluation of reserve tax bills

Interim Work
2001-02

- Prepare background materials and questions for the Joint Committee on Natural Gas Pipelines
- Attend House Oil & Gas Interim Committee meetings, Policy Council meetings, D.C. hearings and other relevant meetings
- Monitor Asian and North American gas events
- Monitor, in conjunction with D.C. lobbyist, energy bills and other events in D.C. and Canada
- Prepare testimony for D.C. hearings and assist Senator Torgerson in meeting with U.S. Congressional members and staff
- Review, monitor, and work with financing expert data and information regarding state ownership issues
- Develop, in conjunction with interested parties and the administration, an economic model to evaluate the various gas options
- Draft speeches and presentations regarding the gas line requested by Senator Torgerson
- Respond to various inquiries from Senators and Representatives

- Work on developing a fiscal model for efficient oil and gas taxation including changes to the severance tax

SCOMM

129:13

Subject: **Phillips signs up for Nigeria LNG**
Date: Mon, 10 Sep 2001 11:24:16 -0800
From: Erika McConnell <Erika_McConnell@gov.state.ak.us>
Organization: Alaska Office of the Governor
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Phillips Oil Unit In Pact For Nigeria Liquefied Gas Plant

Dow Jones Newswires

NEW YORK -- Phillips Petroleum Co.'s (P) Phillips Oil Co. unit signed a memorandum of understanding to develop a new liquefied natural gas, or LNG, facility in Nigeria.

In a press release Friday, Phillips said the deal was signed with its co-venturers, Nigerian National Petroleum Co. and Nigerian Agip Oil Co., along with the Nigerian government.

The memorandum establishes a multidiscipline study team that will evaluate an offshore LNG facility.

The proposed plant, which will be sized at 850 million cubic feet a day of natural gas, is expected to be onstream by 2007.

The gas supply will come from gas reserves within onshore oil and gas fields already operated by an existing joint venture among the companies.

Phillips holds a 20% interest in the joint venture, while the Nigerian National Petroleum Co. holds 60% and Nigerian Agip Oil Co. holds 20%.

--
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AK Highway Natural Gas Policy Council
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Subject: Problems for Mackenzie
Date: Mon, 10 Sep 2001 11:06:38 -0800
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Natives may kill Mackenzie pipeline with new demands
Issues raised by Deh Cho First Nations jeopardize hopes of expediting project

By Ed Struzik, Journal Staff Writer
The Edmonton Journal

Friday, September 07, 2001

A string of new demands from a key aboriginal group in the North may have dealt a body blow to plans for a multibillion-dollar natural gas pipeline down the Mackenzie Valley.

"We're studying the implications of this," says Hart Searle, spokesman

for the Calgary-based consortium that includes Imperial Oil, Conoco Canada, Shell Canada and Mobil Oil Canada.

"But obviously, many of the demands that have been put forward are beyond our ability to do anything about them," he added.

"These are issues between the Deh Cho and the federal government to resolve."

Searle reiterated the consortium's position that a pipeline will not proceed unless it is supported by northern aboriginal groups.

The Deh Cho First Nations in the southern Mackenzie Valley have been the last to take a stand on the pipeline.

Most other aboriginal groups fully support the project and the jobs and economic opportunities it will bring to the economically depressed region of the country.

At a meeting last week, 10 chiefs who represent the 4,000 people in the Deh Cho region resolved to support the project only if a number of conditions were met. The meeting took place in the remote community of Wrigley on the shores of the Mackenzie River, and the decisions were conveyed this week to consortium executives. The demands include:

- Recognition by the oil and gas industry that the terms and conditions of a pipeline must be negotiated through the Deh Cho land-claims process;

- Provisions for sharing of revenues and royalties from the development of oil and gas reserves in the Deh Cho;

- Community impact benefits agreements be in place before the project proceeds;

- Full Deh Cho participation in any environmental assessment.

The chiefs also said they would not support a pipeline unless the hunters and trappers who harvest along the pipeline route back the project.

One senior energy company official suggested the demands could prove to be a "body blow" for the project because a decision on whether to proceed needs to be made before the end of the year.

A quick solution isn't likely because both the federal and territorial governments have indicated that they are determined not to allow the Deh Cho to use the pipeline as leverage in their ongoing land claims negotiations.

They are also extremely uneasy about demands which would essentially push them to the sidelines when it comes to negotiating big projects such as this one.

Nellie Cournoyea, former premier of the Northwest Territories and co-chair of an aboriginal group that is negotiating a one-third interest in the pipeline, says she is disappointed but not surprised by the Deh Cho demands.

However, she insists the pipeline will go ahead.

"One small group of people can not decide on the economic well-being of the majority of people in the Northwest Territories," she said.

"And the reality is the Deh Cho need this pipeline more than any other group in the North."

The one precedent to this does not favour the Deh Cho.

Back in 1984, aboriginal groups in the Northwest Territories refused to sign an agreement that would have given them a share of the revenues that were to come out of the oil pipeline from Norman Wells to Alberta.

In the end, the federal government gave the pipeline company the right of way it needed without an agreement in place, and the aboriginal people were left with nothing.

The Deh Cho, however, do have some leverage this time around.

An American consortium, which includes Phillips, British Petroleum-Amoco and Exxon-Mobil, is looking at the possibility of shipping gas from Alaska undersea to the Mackenzie Valley and then to Alberta.

Should the consortium decide that the route poses too many problems, it will likely go ahead with a pipeline down the Alaska Highway.

Such a decision would almost certainly stall efforts to get Canadian gas out of the Arctic. Most
everyone agrees that two pipelines cannot be built at the same time because there is not enough
skilled manpower, equipment and pipe.

Cournoyea says the Aboriginal Pipeline Group is currently working on a strategy that would ensure that the Deh Cho demands do not stall or kill the Mackenzie Valley
proposal.

"What we won't and can't do though is negotiate their land claim for them," she said. "That's between them and the federal government."

--
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July 19, 2001

ALASKA NATURAL GAS PIPELINE ACT OF 2001

I. Overview

A. Background

- In the 1970s, tight energy supplies generated substantial interest in commercializing Alaska North Slope natural gas.
- The result of this interest was a mammoth proceeding before the Federal Power Commission (FERC's predecessor) in which competing applicants vied to be picked to build a transportation system — a highly contentious and litigious process.
- Concerned that the normal regulatory and judicial review processes would never end, Congress passed a special statute, the "Alaska Natural Gas Pipeline Act of 1976" (ANGTA), transferring the selection decision, under an expedited schedule, to the President and itself. The selected system and operator could then go forward to obtain the requisite regulatory approvals with the benefit of an expedition directive and tight limitations on judicial review.
- The President and Congress designated a project known as the Alaska Natural Gas Transportation System. The southern portion (known as the "pre-build") between Alberta and the Lower 48 was completed in the 1980s and early 1990s. Despite the passage of more than two decades, however, the governmentally selected project for the Alaska-to-Alberta segment has been unable to obtain the financing necessary to go forward.
- The situation in Canada is similar. The Canadian counterpart of the project – a pipeline from the Alaska/Canada border into Alberta – was approved under the Northern Pipeline Act but has not proceeded.

B. Fresh Approach Needed

- Getting access to Alaska North Slope natural gas is an important element of the nation's long-term energy strategy.
- The approach of having the government "pick a winner" has been unsuccessful.
- It is in the national interest to let competitive market forces work. The market, not a governmental selection process, is the best tool for determining the project or projects that can achieve economic viability and provide cost-effective transportation.

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2963 SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPLINES, 2001-02

- Relying on market forces to the greatest degree possible is the currently preferred regulatory approach. Indeed, since the passage of ANGTA, natural gas prices have been deregulated, the transportation and sales functions of natural gas pipelines have been "unbundled," and gas prices are wholly driven by free-market forces.

C. The Concept of the Proposed Legislation

- For purposes of the FERC approval process, the proposed legislation differentiates between the Alaska-to-Alberta ("A-to-B") and the Alberta-to-Lower 48 ("B-to-C") segments.
  - ✓ The A-to-B segment is completely undeveloped, whereas there is a substantial existing B-to-C infrastructure. Thus, the respective needs, competitive dynamics, and likely course of development (e.g., new pipeline vs. expansion) of the two segments differ greatly.
  - ✓ In light of those differences, the proposed legislation relies on a streamlined, market-based approval process for the A-to-B segment and the normal Natural Gas Act approval process for the B-to-C segment.
- The proposed legislation requires thorough review under, and full compliance with, applicable environmental laws.
- To enhance the prospects of success, the proposed legislation seeks to reduce regulatory uncertainty and delay through reasonable expedition measures, deadlines, and limitations on judicial review.
- To rationalize the multi-agency approval process, the proposed legislation provides for a Federal Pipeline Director with strong coordination powers and responsibilities.

II. Section-by-Section Summary of the Proposed Legislation

A. Section 1 — Short Title

- "Alaska Gas Pipeline Act of 2001"

B. Section 2 — Congressional Findings

- This section sets forth findings that support the need for the legislation.
- The findings note the existence of substantial natural gas resources on the North Slope, the importance of those resources to the nation's long-term energy needs, the 1976 enactment of special legislation to facilitate the approval and construction of a transportation system to move Alaska gas to the Lower 48; the failure of that legislative effort, the outdated features of the

previously approved system, and the current renewed interest in constructing a transportation system to move the gas to the Lower 48.

- The findings explain that it is in the national interest to encourage the development of one or more environmentally sound transportation systems through sensible, expedited regulatory procedures and to rely to the extent possible on competitive market forces to determine the future development of North Slope gas.

C. *Section 3 — Congressional Statement of Purpose*

- This section explains that the legislation seeks to expedite the approval, construction, and operation of one or more transportation systems for delivering North Slope gas to the Lower 48 by relying on market forces to determine which projects are economically viable; expediting the certification and permitting processes; ensuring compliance with environmental laws; establishing a Federal Pipeline Director to coordinate and move the process forward; and expediting, and narrowing the scope of, judicial review.

D. *Section 4 — Definitions*

- This section defines various terms used throughout the Act.
- Definition of "Alaska Natural Gas" is identical to that used in ANGTA.
- Uses "Alaska Facilities Gas Project" and "Lower 48 Facilities Gas Project" to differentiate between A-to-B and B-to-C segments, respectively.

E. *Section 5 — Expedited Approval Process*

- Adds a new Section 7(c)(3) to the Natural Gas Act requiring FERC to grant any and all applications to build the Alaskan part of A-to-B facilities if three criteria are satisfied:

  (1) The applicant must have reached an agreement with a "Shipper" of Alaska Natural Gas for the transportation of that gas with the intent that all or a portion of the gas ultimately will be delivered to the Lower 48 States.
  - ◊ A "Shipper" essentially is any person that has entered into an agreement with the applicant for the transportation of Alaska Natural Gas; anyone who, through contract or otherwise, controls Alaska Natural Gas may be a Shipper.
  - ◊ This provision reflects a market-based approach, not unlike that reflected in Section 311 of the Natural Gas Policy Act

  (2) FERC must be satisfied that "rates and charges for, and terms and conditions of" such transportation services can be established in accordance with FERC's usual procedure.

(3) FERC must be satisfied that terms and conditions for compliance with all applicable environmental laws can be established in accordance with FERC's usual procedure.

- The latter two requirements assure that certain key aspects of traditional pipeline regulation under Section 7 of the Natural Gas Act, including protection of ratepayers and protection of the environment, will be followed with respect to any Alaska Gas Facilities Project

- To provide for expedition, FERC is directed to act on any Alaska Gas Facilities application within 18 months.

- Adds a new Section 7(c)(4) to the NGA under which the Commission may issue a certificate authorizing construction of facilities to transport Alaska Natural Gas from the Canadian border to markets in the Lower 48 States. Such applications will be considered pursuant to the Commission's normal Section 7 procedures.

F. *Section 6 — Environmental Reviews*

- Requires a *single* EIS for each proposed "Alaska Gas Project." This means that:
  - ✓ EISs for A-to-B projects will be prepared separately from EISs for B-to-C projects
  - ✓ *Each* proposed project will be studied in a separate EIS
  - ✓ Agencies must work together to prepare a single EIS for each project

- Requires each EIS to be prepared pursuant to the lead agency's regulations and procedures.

- Designates FERC as the lead agency for all EISs for A-to-B and B-to-C projects.

- Sets deadlines for completing the EISs:
  - ✓ Draft EIS within 12 months after filing of complete FERC certificate application
  - ✓ Final EIS within 6 months after DEIS (i.e., 18 months total for EIS preparation)
  - ✓ Deadlines may be extended by FERC for good cause

- Requires consistency between the *scope* of the EIS and the *scope* of FERC certificate application. This means:
  - ✓ EIS focuses on project within FERC jurisdiction (Canadian portions are reviewed by Canadian agencies, not by FERC; this is consistent with current FERC practice)

G. *Section 7 — Federal Pipeline Director*

- Creates the Office of the Federal Pipeline Director in the Executive Office of the President. The Director would be appointed by the President and confirmed by the Senate.

- Overall responsibilities of the Director include "coordinating the expeditious discharge" of all federal agencies' activities on Alaska gas projects (A-to-B and B-to-C). Gives agencies *discretion* to delegate decision-making authority to the Director, but does not require them to do so. (Similar to ANGTA provision for non-enforcement regulatory responsibilities.)

- Specifically charges the Director with responsibilities for "coordinating the expeditious completion" of all environmental and other studies for Alaska gas projects. This role includes coordination with federal, state, local, and tribal agencies, as well as coordination with Canadian agencies (via the State Department).

- Requires the Director to report semi-annually to Congress on the status of all pending applications for Alaska gas projects.

- Authorizes the appropriation of funds for the Director's Office.

H. *Section 8 — Agency Reviews and Decisions*

- Directs federal agencies to expedite their handling of all Alaska gas project actions.

- Requires the federal agencies involved in Alaska gas projects to cooperate and coordinate with one another to expedite the decision-making process – through MOUs, joint documents, joint meetings, etc.

- Prevents federal agencies from including discretionary terms in permits if the Federal Pipeline Director finds that such terms would "prevent or impair in any significant respect the expeditious construction and initial operation of an economically viable and environmentally sound system."

I. *Section 9 — Judicial Review*

- Time limits: challenges to this Act's validity must be brought within 60 days of its enactment; challenges to actions by federal agencies or officers under the Act must be brought within 60 days of such action.

- Jurisdictional Limits: judicial review is limited to claims of constitutional violation or agency action in excess of statutory authority. Precludes claims that federal agency actions are "arbitrary and capricious."

- **Exclusive Jurisdiction of Special Court: challenges to this Act or actions taken thereunder must be brought directly in the U.S. Court of Appeals for the District of Columbia Circuit.**

- **Expedited Procedures: does not impose specific deadline but directs the D.C. Circuit to provide expedited consideration.**

- **Similar limitations on judicial review are contained in ANGTA.**

J. Section 10 — Separability

- **If any provision of this Act, or application thereof, is held invalid, the remainder of the Act is unaffected.**

S._____

IN THE SENATE OF THE UNITED STATES

A BILL

To Expedite the Approval, Construction, and Initial Operation of One or More Economically Viable and Environmentally Sound Transportation Systems for the Delivery of Alaska Natural Gas to the Lower 48 States.

Be it enacted by the Senate and the House of Representatives of the United States of America in Congress assembled,

SEC. 1. SHORT TITLE.

This Act may be cited as the "Alaska Natural Gas Pipeline Act of 2001."

SEC. 2. CONGRESSIONAL FINDINGS.

(a) The Congress finds and declares that—

(1) Over the next 20 years, the demand for natural gas in the United States is expected to increase by more than 50 percent, and the nation's anticipated production, at current growth rates, will fall far short of that level of demand.

(2) One of the largest known reserves of natural gas in the United States, estimated at over 35 trillion cubic feet, is located in Alaska, in the vicinity of Prudhoe Bay. In addition, it is estimated that there may be up to 100 trillion cubic feet of natural gas on the North Slope of Alaska.

(3) If delivered to the Lower 48 States, the known and expected natural gas resources on the North Slope of Alaska would make an important long-term contribution to the nation's energy supplies. At present, however, there is no natural gas pipeline system connecting the North Slope of Alaska to the Lower 48 States.

(4) In 1976, Congress enacted the Alaska Natural Gas Transportation Act (ANGTA), 15 U.S.C. § 719, to expedite completion of a pipeline system connecting the North Slope of Alaska to the Lower 48 States. ANGTA authorized the President and Congress to designate a single project as the Alaska Natural Gas Transportation System (ANGTS), which would be entitled to the benefit of a streamlined regulatory approval process and limited judicial review.

(5) In 1977, the President and the Congress designated an ANGTS project, and the southern portion of that project (known as the "pre-build") was completed between Alberta and the Lower 48 States in the 1980s and early 1990s.

(6) Despite the passage of more than 20 years, parties seeking to develop the Alaska-to-Alberta section of the ANGTS project have been unable to

obtain the regulatory approvals or attract the financing necessary to permit construction of the project to begin.

(7) As a result of the passage of time, some design features mandated for the Alaska-to-Alberta section of the ANGTS project would have to be modified to take full advantage of current technological capabilities, and other changes also may be needed to ensure an economically, environmentally, and technically sound approach.

(8) The nation's energy supply situation has changed in recent times, thereby triggering renewed interest in a variety of proposals to construct transportation facilities to move Alaska Natural Gas to markets in the Lower 48 States.

(9) In concert with this renewed interest in understanding technical requirements and determining if an economically viable transportation system can be developed, an important first step in assessing economic viability is to know whether regulatory approvals can be obtained and environmental impacts assessed in a timely fashion.

(10) Therefore, it is in the national interest to:

(i) encourage the renewed interest in proposals to bring about the transportation of Alaska Natural Gas to the Lower 48 States;

(ii) provide as much regulatory certainty and expedition as practicable for approval and implementation of any such environmentally sound proposals to enhance their prospects of economic viability

and development and thereby to provide the nation with the benefit of one or more cost-effective transportation systems;

(iii) allow for the possibility that the market may support now or in the future the construction of more than one transportation system to move Alaska Natural Gas efficiently to the Lower 48 States;

(iv) rely on competitive market forces, to the maximum extent possible, in determining the future development of Alaska Natural Gas supplies;

(v) encourage the development of one or more pipeline systems for transporting Alaska gas to the Lower 48 States in a manner consistent with

(a) maximizing the delivery of a long-term, reliable supply of natural gas to the Lower 48 States, as soon as possible; and

(b) complying with all applicable environmental laws

SEC. 3. CONGRESSIONAL STATEMENT OF PURPOSE

The purpose of this Act is to expedite the approval, construction, and initial operation of one or more transportation systems for the delivery of Alaska Natural Gas to the Lower 48 States by:

(a) relying on competitive market forces to determine which such system or systems can be built and operated in an economically viable manner;

(b) providing for the expedited review and approval of applications for a certificate of public convenience and necessity and related federal approvals for one or more pipelines transporting Alaska gas to the Lower 48 States;

(c) ensuring the full consideration of environmental impacts and related concerns during the review of any proposed Alaska Gas Projects, consistent with the need to expedite such review;

(d) creating an Office of Federal Pipeline Director to direct the efficient and coordinated participation of, and decision-making by, the various federal agencies and other governmental interests involved in the review and approval of one or more Alaska Gas Projects; and

(e) expediting the resolution of, and limiting the jurisdiction of the courts to review, disputes concerning any aspect of this legislation or the approval process for any Alaska Gas Project.

To accomplish this purpose, Congress intends to exercise its constitutional powers to the fullest extent in the authorizations and directions contained herein.

SEC. 4. DEFINITIONS.

As used in this Act:

(1) the term "Alaska Gas Project" means any Alaska Facilities Gas Project or Lower 48 Facilities Gas Project;

(2) the term "Alaska Natural Gas" means natural gas derived from the area of the State of Alaska generally known as the North Slope of Alaska, including the Continental Shelf thereof;

(3) the term "Commission" means the Federal Energy Regulatory Commission;

(4) the term "Lower 48 States" means the contiguous States of the United States of America;

(5) the term "Lower 48 Markets" means any market for the consumption of natural gas that is located within the Lower 48 States;

(6) the term "Alaska Facilities Gas Project" means any natural gas pipeline system that carries Alaska Natural Gas from the area generally known as the North Slope of Alaska to the border between Alaska and Canada, including any related facilities that fall within the jurisdiction of the Commission; and

(7) the term "Lower 48 Facilities Gas Project" means any natural gas pipeline system that carries Alaska Natural Gas from the border between Canada and the Lower 48 States to any Lower 48 Markets, including any related facilities that fall within the jurisdiction of the Commission.

SEC. 5. EXPEDITED APPROVAL PROCESS.

(a) Section 2 of the Natural Gas Act is amended to include the following additional definitions:

(11) "Alaska Natural Gas" means natural gas derived from the area of the State of Alaska generally known as the North Slope of Alaska, including the Continental Shelf thereof.

(12) "Lower 48 States" means the contiguous States of the United States of America.

(13) "Lower 48 Markets" means any market for the consumption of natural gas that is located within the Lower 48 States.

(14) "Shipper" means, for purposes of section 7(c)(3) and (4) of this Act, any person that has entered into an agreement with a person that is or will

upon its issuance become the holder of a certificate of public convenience and necessity authorizing an Alaska Facilities Gas Project or a Lower 48 Facilities Gas Project for the purpose of transporting Alaska Natural Gas.

(15) "Alaska Facilities Gas Project" means any natural gas pipeline system that carries Alaska Natural Gas from the area generally known as the North Slope of Alaska to the border between Alaska and Canada, including any related facilities that fall within the jurisdiction of the Commission.

(16) "Lower 48 Facilities Gas Project" means any natural gas pipeline system that carries Alaska Natural Gas from the border between Canada and the Lower 48 States to any Lower 48 Markets, including any related facilities that fall within the jurisdiction of the Commission.

(b) Section 7(c) of the Natural Gas Act is amended to include the following additional paragraphs:

"(3) Notwithstanding any other provision of law, the Commission shall issue a certificate of public convenience and necessity to any person for the construction and operation of an Alaska Facilities Gas Project where:

(A) such person has reached agreement with a Shipper of Alaska Natural Gas for the transportation of natural gas through an Alaska Facilities Gas Project on behalf of such Shipper with the intent that all or a portion of such Alaska Natural Gas, along with any other natural gas, will ultimately be delivered to Lower 48 Markets for consumption: provided, however, that the Commission shall not consider the present extent of

transportation capacity downstream of the proposed Alaska Facilities Gas Project;

(B) rates and charges for, and terms and conditions of, such transportation services can be established in accordance with the procedure provided in subsection (e) of this section; and

(C) terms and conditions for compliance with all environmental laws applicable to the proposed Alaska Facilities Gas Project can be established in accordance with the procedure provided in subsection (e) of this section.

Upon the filing of any such application, the Commission shall determine within 18 months whether the agreement between the Shipper and such person meets the requirements of (A) and whether the matters identified in (B) and (C) can be established in accordance with subsection (e) of this section, and, if so, the Commission shall within such period make the findings, attach such reasonable terms and conditions as the public convenience and necessity may require, and issue a certificate, all in accordance with the procedure provided in subsection (e) of this section.

(4) Notwithstanding any other provision of law, the Commission may issue a certificate of public convenience and necessity authorizing the construction and operation of a Lower 48 Facilities Gas Project to any person that has reached agreement with a Shipper of Alaska Natural Gas that will have been first transported through an Alaska Facilities Gas Project for any continued transportation of such gas from the U.S. border with Canada to any destination

within the Lower 48 Markets, provided that the Commission makes the findings and attaches such reasonable terms and conditions therefor in accordance with the procedure provided in subsection (e) of this section."

SEC. 6. ENVIRONMENTAL REVIEWS.

(a) Separate EISs for Alaska Facilities and Lower 48 Facilities Gas Projects.

(1) Before a certificate of public convenience and necessity is issued for any Alaska Facilities Gas Project under Section 7(c)(3) of the Natural Gas Act, a single environmental impact statement shall be prepared for that project and for any gas conditioning plant developed in conjunction with such project in accordance with the National Environmental Policy Act, 42 U.S.C. § 4332(2)(C), and this Act. The preparation of an EIS for a project pursuant to this paragraph shall satisfy the NEPA obligations of each federal agency whose approval is required for that project.

(2) Before a certificate of public convenience and necessity is issued for any Lower 48 Facilities Gas Project under Section 7(c)(4) of the Natural Gas Act, a single environmental impact statement for that project shall be prepared in accordance with the National Environmental Policy Act, 42 U.S.C. § 4332(2)(C), and this Act. The preparation of an EIS for a project pursuant to this paragraph shall satisfy the NEPA obligations of each federal agency whose approval is required for that project.

(b) Any environmental impact statement prepared pursuant to subsection (a) of this section shall be prepared in accordance with the regulations and procedures of the lead agency designated for that statement in subsection (c) of this section.

(c) Lead agency for preparation of environmental impact statements.

(1) The lead agency for any environmental impact statement prepared pursuant to subsection (a)(1) of this section shall be the Commission.

(2) The lead agency for any environmental impact statement prepared pursuant to subsection (a)(2) of this section shall be the Commission.

(d) The preparation of any environmental impact statement prepared under subsection (a) of this section shall be expedited. The draft environmental impact statement shall be issued within 12 months after the certificate application is accepted for filing, and the final environmental impact statement shall be issued within 6 months thereafter, unless the Commission determines for good cause that additional time is needed to comply with environmental or other laws.

(e) The scope of any environmental impact statement prepared under subsection (a) of this section shall correspond to the scope of the certificate application for which such environmental impact statement is being prepared.

SEC. 7. FEDERAL PIPELINE DIRECTOR.

(a) The Office of the Federal Pipeline Director shall be established within the Executive Office of the President. The functions of the Office shall be directed by the Federal Pipeline Director, who shall be appointed by the President, by and with the advice and consent of the Senate.

(b) The Federal Pipeline Director shall be responsible for coordinating the expeditious discharge of all activities by federal agencies with respect to any Alaska Gas Project, from the pre-application consultation stage through the completion of project construction and initial operation. The Director also shall be responsible for coordinating the compliance by all federal agencies with the provisions of this Act with respect to such projects. Such coordination shall include requiring submission of scheduling plans for permits, certificates, grants, or other necessary authorizations. Such coordination may include serving as a "one window point" for filing and issuance of all necessary permits, certificates, grants, or other authorizations, and, consistent with law, federal government requests for data or information related to any application for a permit, certificate, grant, or other authorization. Upon the written agreement of the Director and the head of any federal agency, the agency may delegate to the Director any statutory function vested in such agency related to the functions of the Director, including permitting functions.

(c) The Federal Pipeline Director shall be responsible for coordinating the expeditious completion of all environmental and other studies and reviews of any kind that are required or conducted for any Alaska Gas Project. Such coordination shall include requiring the submission of detailed scheduling plans for completing such studies and reviews within the time periods allowed under this Act and also shall include requiring the submission of periodic reports

on agencies' compliance with such plans. Such coordination also may include serving as the "primary point of contact" for the federal government with any and all participants in such studies and reviews, including

(i) Federal agencies and officials, including those involved in the preparation of an environmental impact statement;

(ii) State, local, and tribal governments and non-governmental stakeholders; and

(iii) Canadian agencies responsible for decisions relating to the transportation of Alaska Natural Gas to the Lower 48 States.

(d) The Federal Pipeline Director shall semi-annually submit a detailed report to Congress on the status of all pending applications for Alaska Gas Projects.

(e) There is hereby authorized to be appropriated, beginning in fiscal year 2002 and each fiscal year thereafter, such sums as may be necessary to carry out the functions of the Office of the Federal Pipeline Director appointed by the President under section 7(a) of this title.

SEC. 8. AGENCY REVIEWS AND DECISIONS.

(a) All actions taken by any federal officer or agency with respect to an Alaska Gas Project shall be expedited, in a manner consistent with completion of the necessary reviews and approvals by the deadlines set forth in this Act.

(b) Federal agencies involved in the review or approval of an Alaska Gas Project shall cooperate and coordinate with one another, under the direction of the Federal Pipeline Director, to expedite the decision-making process and to minimize duplication of effort. Such cooperation and coordination efforts shall include, as appropriate, the following:

(i) memoranda of understanding with applicants or prospective applicants;

(ii) inter-agency memoranda of understanding;

(iii) inter-agency coordination procedures;

(iv) inter-agency coordination meetings;

(v) joint pre-filing or post-filing consultation meetings with project applicants;

(vi) joint public meetings; and

(vii) joint reports, studies, and other documents, including but not limited to the joint environmental impact statement required to be prepared for each Alaska Gas Project under section 6(a) of this title.

(c) Any certificate, right-of-way, permit, lease, or other authorization issued or granted for an Alaska Gas Project shall include the terms and conditions required by law, and may include terms and conditions permitted by law, except that with respect to terms and conditions permitted but not required, the federal officer or agency, notwithstanding any other provision of law, shall have no authority to include terms and conditions that the Federal Pipeline Director determines would prevent or impair in any significant respect the expeditious construction and initial operation of an economically viable and environmentally sound system for transporting Alaska Natural Gas to the Lower 48.

(d) Any federal officer or agency, with respect to any certificate, permit, right-of-way, lease, or other authorization issued or granted by such officer or agency for an Alaska Gas Project, may, to the extent permitted under laws administered by such officer or agency, add to, amend, or abrogate any term or condition included in such certificate, permit, right-of-way, lease, or other authorization except that with respect to any such action that is permitted but not required by law, such federal officer or agency, notwithstanding any such other provision of law, shall have no authority to take such action if the Federal Pipeline Director determines that it

would prevent or impair in any significant respect the expeditious construction and initial operation of an economically viable and environmentally sound system for transporting Alaska Natural Gas to the Lower 48.

SEC. 9. JUDICIAL REVIEW.

(a) Exclusiveness of Remedy. Notwithstanding any other provision of law, the actions of federal officers or agencies taken with respect to any Alaska Gas Project shall not be subject to judicial review except as provided in this section.

(b) Limitations on the Filing of Claims.

(i) Claims alleging the invalidity of this Act may be brought not later than the 60th day following its date of enactment.

(ii) Claims alleging that any action taken by a federal officer or agency in connection with an Alaska Gas Project will deny rights under the Constitution of the United States, or that any such action is in excess of statutory jurisdiction, authority, or limitations, or short of statutory right, may be brought may be brought not later than the 60th day following the date of such action, except that if a party shows that he did not know of the action complained of, and a reasonable person acting in the circumstances would not have known, he may bring a claim alleging the invalidity of such action not later than the 60th day following the date of his acquiring actual or constructive knowledge of such action.

(c) Exclusive Jurisdiction of Special Court. A claim under subsection (b) of this section shall be barred unless a complaint is filed prior to the expiration of the time limit specified in that subsection in the United States Court of Appeals for the District of Columbia

Circuit acting as a Special Court. Such court shall have exclusive jurisdiction to determine such proceeding, and no other court of the United States, or any state, territory, or possession of the United States, or of the District of Columbia, shall have jurisdiction of any such claim in any proceeding instituted prior to or on or after the date of enactment of this Act.

(d) Expedited Procedures. With respect to any claim under subsection (b) of this section, the United States Court of Appeals for the District of Columbia Circuit shall set the matter for expedited consideration, taking into account the national interest as defined in section 2 of this Act.

SECTION 10. SEPARABILITY.

If any provision of this Act, or application thereof, is held invalid, the remainder of this Act shall not be affected thereby.

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July 17, 2001

Commissioner Wilson Condon
State of Alaska, Department of Revenue
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99811-0400

Dear Commissioner Condon,

This letter addresses the list of 13 questions forwarded by the Governor and staff via email and discussed in a conference call. As requested, we have addressed the issues falling within our expertise, have offered our judgments where they might prove helpful, and have provided references for types of analysis beyond CERA's expertise and for which other firms might be of more assistance.

CERA addresses the long-term future of energy markets and industries in the context of scenarios, rather than single forecasts. This allows our clients better to understand the forces driving the future, and how significant uncertainties can affect the future strategically. The State of Alaska has participated in the scenarios-based CERA study, "Toward New Frontiers: The Future of Gas Supply in North America," (hereafter the "supply study") which addresses several of the questions that you have asked, including competing sources of supply and their timing and sequence of development. These answers draw upon that body of work. You have been provided physical copies, and have access also via the Internet.

A summary of the scenarios developed in the supply study — *Gas Favored*, *Supply Realignment*, and *Aftershock* — is provided below for your convenience and immediate reference. These descriptions, along with supply/demand balances and prices under each scenario, may be found in Section II of the supply study.

The Gas-Favored Scenario

The Gas-Favored Scenario depicts an industry that has established the foundation for both price and demand growth over the longer term. Strong economic growth (averaging 3 percent through the study period), a strong competitive position for gas in power generation markets, and favorable environmental policies drive a surge in gas demand for power generation. By 2003, demand climbs to 24 trillion cubic feet (Tcf) in the United States. In Canada significant new pipeline infrastructure results in continued strong pricing, with consumption rising to 3.0 Tcf and exports climbing to 4.1 Tcf by 2003.

The expectation of continued pricing strength creates the financial incentive for increased exploration and production activity. The crucial areas upon which so much of production health depends — US Gulf deep water and the Western Canadian Sedimentary Basin (WCSB) — respond well to drilling activity. Higher prices also facilitate the expansion of the gas pipeline and distribution infrastructure needed to meet the growing demand. After intense market pressures through 2003, the supply-demand balance settles to a more sustainable balance. Gas volumes from the Rockies and Atlantic Canada are strong, and the scenario experiences the highest utilization of LNG import facilities. The health of the more traditional supply regions means that the need for northern frontier supplies is delayed until 2011. Gas demand in the United States reaches 28.9 Tcf by 2010.

The Supply Realignment Scenario

The Supply Realignment Scenario is characterized by intense market pressure, where demand growth is constrained for limited periods by the amount of gas supply available. Moderate economic growth (averaging 2.5 percent) and favorable environmental policies drive a surge in gas demand for power generation. However, gas supplies fail to keep pace. The US Gulf Coast experiences high decline rates in onshore and shallow offshore supplies, and the deep offshore does not deliver the incremental volumes of gas that were generally expected as oil-related drilling and associated gas production grow only slowly. The supply build of the WCSB is also moderated. Continuing gas demand and tight supply keep natural gas prices very high through 2003.

This tight market balance causes large-scale reactions. On the demand side the United States experiences a significant loss of demand among feedstock users of gas — namely ammonia and methanol manufacturers. On the supply side high prices attract aggressive activity in frontier areas, including development of the Canadian offshore East Coast, an acceleration in plans for LNG expansion, and an aggressive timeline for the development and connection of the Mackenzie Delta and northern frontier. In this context Alaskan gas reaches the US market in 2008.

The demand downturn and this supply acceleration in turn moderate price in the latter half of the study period. Eventually, growth in US and Canadian demand leads to renewed tightening in the market balance and, after 2010, another cycle of increased pricing strength. Gas demand in the United States reaches 26.7 Tcf by 2010.

The Aftershock Scenario

The Aftershock Scenario plays out the events that would occur surrounding a recession in the near term. After an initial year of overheated economic growth, the Federal Reserve Board takes action to slow the economy. These efforts, along with lingering effects from the readjustment of stock equity valuations, help to plunge the economy into a serious recession that lasts from late 2001 through 2003. The recession softens growth in power demand and causes a decline in industrial demand.

The initial pricing strength during the period of overheated economic growth creates the financial incentive for increased exploration and production activity. The crucial areas upon which so much of production health is dependent — US Gulf deep water, WCSB, and Rockies — respond strongly to activity. These supply responses emphasize the

price downturn that results from the subsequent softening of demand. In this challenging market environment a lower cost pipeline from the Mackenzie Delta is built in 2009, before an Alaskan line, and Alaska gas flow is delayed until mid 2012.

As production begins to moderate in response to these new price signals, the economy itself begins to recover, so that by 2005 the supply/demand balance returns to somewhat tighter levels. Gas demand in the United States reaches 26 Tcf by 2010.

The responses to your individual questions follow:

Question 1: Form of royalty.

Question 1, Part A: Alaska has the option to take its one-eighth share of royalty "in-kind" or "in-value." Given the proposed size of the project and the known reserve, to what extent might Alaska's royalty gas be needed "in-value" to ensure sufficient throughput and project viability?

In general, transportation rights – that is, the rights to transport services on natural gas pipelines — are separate from ownership of reserves (and of ownership of the pipe) in the United States and Canada. An election by the state to take royalties in-kind is quite meaningless without a mechanism to monetize the gas. In order to do that, the state would either have to procure firm transport rights from the field area to markets in the L-48, or to entrust an agent to do so on its behalf. The obligation for the transportation costs would rest with the state in either case. Without an ability to move the gas to market, the state's royalty gas could be trapped in the ground as the producers continue to fill available pipeline capacity (which they have secured) with their equity gas. While such a situation may seem unlikely, producers have had gas production interrupted or shut-in for lack of pipeline capacity rights (in the Rocky Mountains and deep-water Gulf, for example). If the state elects to take its gas in-kind it should commit to accompanying access to firm pipeline transport capacity.

If the state were to take royalty in-kind gas for delivery to markets only within the state, the pipeline should be designed to only accommodate that flow to the intended delivery points. Otherwise, the state may be obligated to pay for unused capacity downstream of those deliveries, or the unused capacity would add to the unit cost of transport for the producers' gas and thus threaten the project economics. To avoid this threat, additional pipeline capacity could be built from the field to in-state delivery meters, and the state would have the obligation for paying for that additional capacity or passing it on to consumers. Commercial and distribution interests within the state may also contribute some share of the cost if they were to contract for gas delivery to similar points. Establishing a market value for this in-state delivery may prove difficult and may result in the state not receiving the full value for the commodity

The adequacy of reserves and productive capability does not appear to be an issue limiting the viability of this project. The type of royalty elected is unlikely to affect the economics of the project due to any lack of producibility. In other words, the reserves and productive capability are sufficient to fill any reasonable pipeline under consideration, whether the state takes its gas in royalty or in-kind.

Question 1, Part B: What are the economics associated with taking royalty gas in-kind along the line, such as in the Fairbanks area, for use as home heating and electrical generation compared to current energy sources?

The cost of gas delivered to homes and business in comparison to that of the energy sources now used usually requires an engineering study to determine the cost of a distribution system, and is beyond CERA's general expertise. However, for reference, existing non-gas distribution costs (from major pipeline systems to individual

consumers) in the US Lower 48 tend to range from approximately $1.50 to $5.00 per MMBtu to residential and commercial consumers, depending upon real estate costs, population densities and industrial loads on the distribution systems. Non-gas distribution costs within Alaska will likely be well above average, given the low-population density. However, high costs for alternate energy sources, potential industrial or power generation host loads, and reasonable real estate costs may offset a portion of higher than average distribution costs, potentially allowing gas to compete with other sources of energy in localized instances. With Fairbanks proximity to the line, gas may prove to be a competitive energy source there, but gas may not be competitive in other areas absent major host industrial or power generation loads.

A distribution franchise holder would normally conduct such a study. In the largest scale recent new franchise acquisition, Sempra Energy procured the franchise for the development of a provincial distribution systems off of the Maritimes and Northeast pipeline in Nova Scotia. A year after being awarded the contract, a decision was made not to move forward with the majority of that development. In that instance the economics did not work, even in a province more densely populated than Alaska. This is a result of the lack of incentive for existing residential and commercial fuel users to switch to gas given the higher comparative cost of the gas as well as the high initial costs of delivery and conversions. A new distribution system is more expensive than the costs suggested above and needs to be added to the cost of the gas to the consumer. This is a condition that Alaska is likely to face as well.

Question 1, Part C: Alaska has the option of switching back and forth between taking its royalty in-value or in-kind. It can make these switches on six-months notice. It is possible that during the early years of project operation Alaska would want to take its royalty in-value, and then later switch to taking it in-kind to supply feedstock or fuel for some kind of industrial development. Would the possibility of exercising this option affect the design of the project? How would the possibility of exercising this option affect the economics of the project?

Again, switching from royalty in value to royalty in-kind may be of little use to the state unless additional pipeline capacity is built from the producing area to the in-state delivery meters, and unless the state also procures transport capacity to match its royalty production. CERA assumes the state would not consider using Alaska-Alberta capacity to deliver gas within the state; that could indeed burden either the state or the project. If additional capacity within the state were built, then the state's switching royalty methods would not necessarily be of major concern to the producers. However, the state would be expected to pay a rate for this short-haul capacity that would not increase the producers' cost of further expansions of long-haul capacity. The state would likely have to make this commitment at the design stage of the pipeline, thereby making a future switching option somewhat meaningless. While capacity could be added at a late date, the state should not expect to pay a low transport rate based only on the cost of additional compression, without sharing in a fair manner the full cost of the initial pipeline and rights-of-way. Disputes based on average ("rolled-in") and incremental rates, and who pays them, are quite common in the Lower 48.

Unless the state intends to deliver the gas for a lower cost than could be obtained from the producers, there is no inherent value in using "state-owned" gas. A true market value for the gas would enable development to occur without using in-kind gas.

Questions 2 and 3: Petrochemical industry possibilities

Question 2: What types of in-state petrochemical industries using Alaska gas might be economically viable and competitive in world markets? To what extent would such developments be dependent on a tidewater location (and an additional gas spur line)?

The most obvious industries based on natural gas are methanol, ammonia and petrochemical. The viability of all does relate to global economics. Delivery to market would be a key consideration. Therefore, a tidewater location for Alaska development would be essential. This suggests that the most economic location of the facilities would be on the coast, with a gas pipeline from the mainline to that location. The additional cost of transportation from the North Slope to a coastal location (likely either Cook Inlet or Valdez) would burden any development with additional costs that other world sources are unlikely to incur. This additional cost would be for both the mainline and the spur line. The comments on the development of in-state gas delivery are also valid here; in other words, any development would have to ensure that it did not strand downstream pipe and therefore negatively affect the major pipeline development economics. Without an inherent advantage, such as gas costs that are lower than other world stranded sources, new facility development is not likely to fare well economically.

CERA does not analyze petrochemical markets worldwide. We have a relationship with Dewitt and Company partly for this purpose, and recommend contact with:

Earl H. Armstrong
Managing Director
Dewitt and Company
16800 Greenspoint Park
North Atrium, Suite 120
Houston, Texas 77060-2386
281-774-7298
earmstrong@dewittworld.com

We have not contacted Mr. Armstrong directly concerning this referral, but would be more than willing to do so if this would be of help.

Question 3: What is the most economic use of Alaska's natural gas liquids?

This is a decision that will be made by the producers. The natural gas liquids (NGL's) that will be produced with the gas are ethane, propane and butane. All can be used as fuel, petrochemical feedstock or specialty use. Ethane will be the largest component. Its use is highly dependent on the cost of the gas itself, as recent events have demonstrated. Over the past winter, the high cost of gas made it uneconomic to use the ethane for petrochemical feed and as a result it was left in the gas stream and sold alongside the natural gas. Propane is used as a heating fuel as well as a petrochemical feedstock but will be available in lower volume. The smallest volumetric component of

the NGL's is butane, most commonly known for its use in lighters. Its primary uses are fuel, petrochemical and refining.

Current plans are to ship the NGL's as part of the natural gas stream thereby reducing the cost of transportation on a Btu or heating value basis. Removal of the liquids in Alaska may have a detrimental affect on the pipeline economics. Liquid extraction facilities would add to the cost and complexity of the main objective of getting the pipeline built to move the natural gas to market.

While some small-scale extraction of NGL's may be attractive to serve local markets, it is unlikely to be economic to do a full extraction. As an example, a full-scale extraction would result in approximately 85,000 BPD of ethane and 50,000 BPD of propane at a gas flow of 2.5 Bcfd. The only effective disposition of these liquids would be piping or shipping to market (which would not be economic) or development of base petrochemical facilities that would produce ethylene and propylene. The likely location for an extraction facility would be on the main pipeline, which would necessitate a liquid pipeline to either Cook Inlet or Valdez. The coastal location would be the likely choice for the petrochemical facility. A gas pipeline volume of 3 to 4 Bcfd would be the minimum for a single-train world-scale facility of 3 billion pounds per year of ethylene. As a comparative example, Alberta has 8.5 billion pounds per year of capacity and has the dual advantages of lower gas prices (relative to Henry Hub) and a low Canadian dollar. The ethylene and propylene could be further upgraded to polyethylene and polypropylene, but this would further escalate the capital requirements. It would be difficult to develop these facilities and be competitive in a global market without state subsidies.

Another looming obstacle to consider is the importance of the NGL's, especially the ethane, to the government of Alberta. Given the cost and obstacles to development within Alaska, it may be an appropriate trade-off to leave the liquids in the gas in exchange for approval from Alberta, which will play a significant role in the approval process for the pipelines required to get the gas to L-48 markets.

An approach that is not recommended is to allow the liquids to flow initially and later extract them in Alaska after facilities have been developed in other locations. This "upstreaming" has occurred in the past, been highly contentious, and could negatively impact the gas pipeline economics in the future.

Liquids extraction will be required in Alberta if it has not occurred before then since the majority of the pipeline infrastructure from that point forward cannot accommodate the liquids content. Alliance is the only pipeline with a high enough operating pressure to maintain the liquids in the gaseous form.

Question 4: What other potential supply sources are the most likely competitors with Alaska to fill the gap between North American demand and supply?

A complete discussion of each major supply area in North America can be found in Section III of the supply study, and Appendix B provides the production outlook by scenario for each major basin. In brief, the major competitors with Alaska gas to serve demand growth include (production growth is provided below on a "wet" basis, including the Btus associated with liquids in the gas stream):

- Western Canada. The Western Canadian Sedimentary Basin (WCSB) is far from a mature producing area. Although drilling in the basin must extend both deeper and farther afield from the traditional shallow drilling in southern Alberta to sustain production increases, potential to grow production in this basin is significant. CERA expects production growth of between 4.0 (Aftershock) and 7.2 (Gas-Favored) Bcf per day from the WCSB between 2000 and 2015. This expected growth is the major reason producers must, and are, evaluating the cost of building from Alaska not only to Alberta but also directly to markets in the US. The WCSB is currently showing signs of renewed growth after flat production in 2000. In 2001, production is expected to increase by 650 mmcfd and higher in 2002.

- Deep-water Gulf of Mexico. After declining by more than 1.0 Bcf per day since 1998, net production in the Gulf of Mexico is expected to begin to increase this year as the ramp up of production from deep-water fields offsets the decline in shallow-water production. Although the decline in shallow-water "shelf" production is expected to slow, shelf production will continue to decline. Overall production from the Gulf of Mexico is expected to increase by a range of 3.2 Bcf per day (Supply Realignment) to 6.4 Bcf per day (Gas-Favored), depending upon the scenario, from 2000 to 2015. A driving force of the Supply Realignment Scenario is disappointment in growth in deep-water production. In this scenario overall Gulf production peaks in 2010. The future of deep-water production is both a driving force in the North American gas market, and also a major uncertainty.

- The Rocky Mountains. Growth potential in the Rocky Mountain States continues to be large, hampered mainly by access restrictions and the separate and piecemeal development of individual plays and the associated infrastructure. The proximity of the California market, however, and the pipeline infrastructure now planned from the Rockies to California, may provide the impetus for development that this region needs. CERA expects production growth of between 3.0 (Aftershock) and 3.9 (Gas-Favored) Bcf per day from this region by 2015.

- Atlantic Canada. Development potential on the Scotian Shelf offshore Nova Scotia remains immense but requires concurrent pipeline development. Nevertheless, CERA expects Atlantic Canadian production to grow by 2.4 to 2.7 Bcf per day by 2015. Production development announcements will ensure that this area will grow to over 1 Bcfd by 2005.

- LNG imports. With the reactivation of all existing import facilities, plans for new facilities underway, and growing investments in liquefaction facilities worldwide, LNG imports into the US are on a track to exceed even the strong growth expected in the supply study. In the study, CERA incorporates growth in LNG imports of between 2.0 and 2.9 Bcf per day between 2000 and 2015. However, this is achieved using only existing import facilities. CERA's current study of worldwide LNG markets is likely to place the growth in LNG imports even higher — up to 4.0 or even 4.5 Bcf per day. This is based upon recently announced liquefaction investments as well as multiple plans for added import facilities into the US.

These supply sources are potential "competitors" with Alaska gas in a limited sense with regard to project approval, and a much greater and more direct sense if and when all projects and growth proceeds. Significant Alaska gas production is dependent on a single large-scale commitment and a corresponding huge capital investment in pipe. As well, the sequencing of new global LNG supplies depends more on one-time discreet capital investment decisions than on basin development economics. The outlook for the basic supply / demand fundamentals by project participants is the foundation for the project decision rather than the usual sense of competition among supply basins.

In the broader context of the energy marketplace other competitors for Alaska gas emerge. For one example, clean-coal technologies are a significant competitor for power generation loads, the major growth market for gas. Should clean coal effectively penetrate new generation markets, it would indirectly compete with all new gas supply sources by reducing the gas demand requirements.

Question 5: What are the locations, time frames and major hurdles for competing sources of gas to meet future North American demand?

The locations, timing, major hurdles and sequencing of supplies is best addressed in a scenarios context for the future, and a major theme of the supply study is this sequencing of supply under three alternate scenarios. A workshop format often works best in addressing the many issues raised by a general request such as this and such a workshop could be provided within the framework of CERA's relationship with the State of Alaska. This written response discusses the major drivers and reasoning behind the sequencing of supply sources in each of the scenarios.

The primary locations are as described above in Question 4. The time frames and major hurdles for competing sources of gas are best addressed by individual scenario. More complete discussions of issues relevant to this question can be found in the supply study by scenario in Section 2, and by major supply region in Section 3.

In the past a more unique set of circumstances needed to coincide to bring an arctic project to fruition and a more narrow window of opportunity existed. Today, the dynamics of supply and demand suggest a greater need for arctic gas. All three scenarios demonstrate a need for some arctic gas, outlining not only a need but also a wider "window". Recent events, driven by substantially higher prices, such as the plethora of LNG project proposals and new coal-fired power plants, indicate that the window may be at risk of narrowing once again. Absent these factors, the issues for development relate more to timing and volume than the need for arctic gas. Depending on the particular scenario, arctic gas comes on in 2007, 2009, or 2011. Although the mechanism of delivery is still a subject of debate for northern gas, the need for a large volume of gas into the Lower 48 states is not. The economics for development of new sources of supply are expected to be in place to move major projects forward.

Supply Realignment

Time Frame

In this scenario the pace of discovery in the deep-water Gulf of Mexico declines, resulting in a need to realign US supplies away from traditional areas toward the frontiers. In addition, supply does not grow and in fact declines in many traditional onshore US producing areas. With demand pressure continuing but supply not keeping pace, it is not surprising that an arctic gas pipeline is built first in this scenario.

The strong prices in today's market lead to project commitments before the end of 2001. The plans for northern development include large project(s) that ultimately bring both Alaska and Mackenzie gas to market. The size of the project(s) is nominally 4 Bcf per day, increasing to an ultimate design of 4.5 Bcf per day.

Detailed design begins in late 2001 and continues for 2+ years. This design incorporates a northern or arctic segment as well as a market segment to the pipelines. It also includes development of reserves and liquids extraction facilities. Regulatory

applications begin in late 2001 and continue through 2002, with approvals coming in 2003 and 2004. Some construction preparation activities begin in late 2003, with main construction efforts beginning in 2005. Equipment orders begin in 2004 for long lead items, with most procurement occurring in 2005. Construction continues through 2007 and beyond as the projects are ramped up. In-service of the initial arctic supplies begins in midyear 2007, with flows increasing through 2008 and 2009. Initial Mackenzie flows begin in mid-2009.

The combined gas flows reach 3.5 Bcf per day by 2010 and achieve a maximum of 4.25 Bcf per day by 2015. The market segment of pipe includes 1.75 Bcf per day in 2007–08 to the US Midwest and 1.6 Bcf per day to the West Coast in 2007–09. Ultimately, pipeline capacity to these regions for 2007 and beyond will reach 2.7 Bcf per day to the Midwest and 2.45 Bcf per day to California and the Pacific Northwest. That total, although primarily for arctic gas, also includes some increase for WCSB growth.

Major Hurdles

Under supply realignment conditions, an early decision to move forward with an arctic pipeline project itself represents a major hurdle for competing sources of supply. While a decision by the producer consortium to move forward would not likely be reversed based on temporary price movements, the risk of reversal would relate more to large-scale events. Investment in most onshore and shallow offshore supply areas can and will respond more quickly to price changes. However, the timetable for arctic development in this scenario is aggressive and optimistic, and any unexpected delay in the development process would delay the in-service date beyond that in this scenario. In fact, a commitment before the end of 2001 is beginning to look doubtful, suggesting a delay for project in-service to 2008

As long as near-term prices remain strong, ongoing decisions for traditional supply growth will be made and development will continue. While demand pressure allows room for development of other frontier sources, decisions regarding current sources of supply will continue. Delays or deferrals of those decisions are unlikely to occur until after the onset of significant frontier supply. At that time, weaker prices may result in reduced activity as arctic gas and/or LNG displace onshore US gas growth.

LNG imports increase within the capacity of existing facilities, but some potential imports are rerouted to other markets, resulting in a slightly smaller increase in net imports than in the Gas-Favored Scenario. Again, new greenfield facilities are a distinct possibility as a result of recent events.

Aftershock

Time Frame

In the Aftershock Scenario the recession that begins in 2001 defers plans for northern development. Although the recession is brief and is followed by strong economic growth, project proponents and developers are reluctant to proceed immediately after the recovery. This caution leads to the development of a much smaller project initially, likely a Mackenzie River line as a first step. Alaska gas does not enter the marketplace until 2012 in these conditions.

Commitment to northern development is still made in 2001/2002, but the recession slows the process, both in the project design and in the regulatory submissions. Design begins in 2002, with initial regulatory filings beginning in late 2002. The process is not stopped but drags out over a longer time frame. Detailed design is not completed until 2005 and approvals begin to stream in from late 2004 through 2006. Long-lead equipment orders begin in 2006, with some site preparation beginning late that year. Construction begins in 2007 and first gas flows of 1 Bcf per day begin in early 2009. Flows increase to 1.5 Bcf per day by 2011. Alaska gas begins movement in mid-2012, and total volumes climb to 3.5 Bcf per day by 2013 and reach their maximum of 3.95 Bcf per day by 2014.

The smaller initial size of the northern development in this scenario leads to a more incremental approach to the market segment of the capacity. Expansions to the Midwest of 400 MMcf per day are required in both 2009 and 2010, with expansions of 200 MMcf per day in both years to California and the Pacific Northwest. Ultimately, 2.6 Bcf per day is built to the Midwest, while 2.1 Bcf per day is constructed to the West Coast markets.

Major Hurdles

Low demand and prices create major hurdles for capital-intensive supply developments in the Aftershock Scenario. In a challenging environment for all new supply sources, Alaska gas is especially disadvantaged in terms of timing, as are eastern Canadian and LNG supplies. Supply growth from these sources is delayed as the capital investments are put off. For Alaska and offshore eastern Canada, volume growth over the 15-year period is near that in the Gas-Favored Scenario. For LNG, in which investment will occur in many phases, overall volume growth is 600 MMcf per day less in Aftershock than in the Gas-Favored Scenario.

Several onshore basins that require a consistently high level of investment in order to grow are disadvantaged even more. These include the WCSB (growth is 3.2 Bcf per day less than in the Gas-Favored Scenario), the Gulf of Mexico (1.7 Bcf per day less), and the onshore Gulf Coast (1.2 Bcf per day less). These areas never make up the increment of investment lost during the recession and the sustained period of low prices. The reduction in demand that accompanies the recession offsets this reduced supply development and pushes the need for frontier supplies further into the future.

Gas-Favored

Time Frame

In this world, demand growth is strong, driven by strong economic growth and environmental pressure on fuels that might otherwise compete for power generation load. While gas prices rise in real terms, this demand growth is also driven by a strong but consistent and competitive gas price, which in turn is enabled by strong supply growth in traditional supply areas. Gas attracts demand in part because supply growth enables gas to remain competitively priced. The result is that the fundamental need for arctic gas is delayed as traditional supply areas show continued strength.

A pipeline from the arctic enters service in 2011 in this scenario, as the Gulf of Mexico, Western Canada and even the traditional onshore US basins continue to grow but cannot keep pace with demand increases. Importantly, gas discoveries in the deep-

water Gulf of Mexico continue at a strong pace, something that is now far from certain. In addition, production in the Permian grows in only this scenario, while the US Gulf Coast onshore grows by nearly 3.0 Bcf per day. Supply growth in all other competing areas, as well as unexpected resiliency in traditional basins, delays the need for Alaska gas.

Discussion, lobbying, and analyzing are the predominant activities until 2002. Although detailed design begins in 2002, no consensus and commitment is made until 2003, when activity begins more in earnest. The regulatory process is initiated in late 2004 through 2005, with approvals coming in 2007–08. Initial construction preparation begins in 2007–08 as well, with construction in full swing by 2009. Initial flows begin in midyear 2011, with volumes reaching 2 Bcf per day the following year. Volumes continue to ramp up to 2.5 Bcf per day in 2013 and 3.5 Bcf per day in 2014 before reaching 3.86 Bcf per day in 2015. Flows may increase even further beyond the study period.

The market segment will require 900 MMcf per day of additional capacity to the Midwest in 2011, followed by annual increases to reach a total of 3.0 Bcf per day by 2015. Western capacity to California and the Pacific Northwest will require increases of 800 MMcf per day in 2011, followed by annual additions raising the total to 2.75 Bcf per day by 2015.

Major Hurdles

Achieving continuous supply growth in many traditional US producing areas will be quite challenging. Indeed, the resiliency in supply from traditional producing areas in this scenario is well above current conventional wisdom, and many producers challenge this aspect of the Gas-Favored Scenario. However, CERA believes this growth is feasible, despite numerous challenges, in an environment of continued healthy real prices, a pace of technological change that allows steady reductions in real finding and development costs, and strong drilling activity.

Ramping up LNG imports above the capability of existing facilities will also prove challenging. CERA expects LNG imports to increase quickly through existing facilities, with imports limited by feasible operating rates and tanker berths. The theoretical limit of current tanker berths is approximately 4.5 Bcf per day, while operational feasibility may limit imports through these facilities to near 4.0 Bcf per day. New LNG facilities face many hurdles, including permitting in the US, added pipe costs if not in the US, permitting processes in Mexico, and the added capital associated with new vaporization. In the gas-favored world total LNG imports reach near the theoretical maximum of 4.0 Bcf per day.

Strong development interest in recent months in both LNG supply and in vaporization into the North American market indicate that LNG imports may increase beyond the capability of existing plants in all cases, despite these challenges. The lower individual discreet investment costs, the smaller project size, the smaller environmental "footprint", the shorter timeframe, and the fewer jurisdictions for approvals do suggest the challenges may be fewer and smaller than those faced by arctic gas pipelines.

Question 6: What is the range of throughput of Alaska North Slope gas necessary for a viable project? Will North American demand be able to accommodate those volumes?

Minimum viable capacity depends upon a reliable estimate of costs, which at this time is unavailable. The minimum economic pipeline capacity would be an estimated 2.5 to 3.0 Bcf per day under the most favorable cost assumptions, but CERA understands that producers are now focusing on a capacity of 4.0 Bcf per day or higher. Using simplified but standard pipeline cost planning and estimation metrics, a pipeline capital cost range of $10 billion to $15 billion would result in an annual pipeline cost of service of approximately $2.0 billion to $3.3 billion (20-22 percent of capital). Major annual costs include the return of and on capital (depreciation and the costs of debt and equity), labor, operating and maintenance expenses, and general and administrative overhead costs. The resulting unit transport costs are provided in the tables below:

Simple Transport Cost Estimates:
Pipeline Capital: $15,000,000,000

	Average Daily Throughput (Mcfd)	
	2,500,000	4,000,000
Annual Costs	Unit Transport Costs ($/Mcf)	
20%	$ 3.29	$ 2.05
22%	$ 3.62	$ 2.26

Therefore, if pipeline costs are close to $15 billion, then a throughput of 4.0 Bcf per day and a Chicago price of $3.00 are required to offer a netback of $0.74 - $0.95 per Mcf to producers, depending upon the operating cost structure of the pipeline.

If cost estimates are closer to $10 billion, then an initial throughput of 2.5 Bcf per day may be more acceptable to producers, as it would offer a potential netback of $0.81 in a $3.00 Chicago price (see table below).

Simple Transport Cost Estimates:
Pipeline Capital: $10,000,000,000

	Average Daily Throughput (Mcfd)	
	2,500,000	4,000,000
Annual Costs	Unit Transport Costs ($/Mcf)	
20%	$ 2.19	$ 1.37
22%	$ 2.41	$ 1.51

If costs are closer to $15 billion, then an average throughput closer to 4.0 Bcf per day is therefore required under most ranges of price expectations. If costs can be held to $10 billion, then pipelines designed for lower initial throughput become an option.

These are rough "rules of thumb" that are not completely applicable here due to several other factors. The first is that as a high pressure, liquids-rich gas pipeline, the cost on a Btu basis is reduced from the cost on a volumetric or Mcf basis. In other words, the liquids carry some of the cost of transportation, thereby potentially reducing the cost of the gas transportation. This was a premise that the Alliance pipeline was built on. The second factor is that the transportation from Alberta to market is unlikely to be a new "greenfield" pipeline. It is more probable that the second segment of the line will be accomplished by the different levels of expandability on the existing pipelines out of western Canada (PGT, Northern Border, Alliance and TransCanada). There are levels of expansion capability on all those lines, starting with simple compression, moving to looping and compression all the way to "twinning" of a line or lines. All these levels of expansion are less expensive than a new line and will also allow delivery to different markets than a single new pipe would allow. An estimate of the average unit cost of these various expansions is in the $0.80 – $0.85 / mcf range for the Alberta to market portion of the line. The third factor that may become necessary in order to enable construction of an arctic pipeline is a divergence from conventional financing and risk sharing, whereby all parties (producers, pipelines, finance and government) play a role.

Another way to view the cost is from a transportation-only perspective. Using the cost ranges given by the various project proponents, the Alaska to Alberta portion ranges from $ 0.80 to $1.20, the intraAlberta portion is likely to be $0.20 – $0.25, with the Alberta to market portion adding $0.80 – $0.85, for a total project transportation cost of $1.80 - $2.30. This is the minimum market price required before any consideration for production costs, royalties, taxes, etc. that will be used for project evaluation. The irony of any pipeline construction is that once built the fixed costs have to be paid regardless of movement of gas therefore becoming "sunk cost". The shipping decisions then arguably are based on variable of operating costs.

There is little question of the ability of the US and Canadian markets to absorb these supplies. If a pipeline is build, the gas will flow and will be consumed in the market. The outcome is likely to be downward pressure on prices. The real question is what is the pricing impact and how prolonged is it likely to be? In the supply study arctic deliveries of 3.9 – 4.3 Bcf per day are absorbed in the context of Henry Hub prices in the $2.07 (minimum Aftershock year) to $4.64 (Gas-Favored 2015) nominal range. These volumes are "ramped up" over time; a faster build to the higher volumes is going to have a more significant impact on price. Obviously, the lower end of that range could be below the full cost of transportation and if that outcome were the expectation of a producer, it would negatively affect the decision to proceed while an expectation of the higher price is well above the project threshold. As mentioned earlier, the anticipation of higher LNG volumes in a similar or earlier timeframe is going to have an added impact.

Question 7: In light of the above, what is the likelihood and viability of an additional gasline project from the Mackenzie Delta?

The likelihood and viability of gas from the Mackenzie Delta is dependent on a number of factors — routing of the Alaska gas pipeline, timing of both projects if separate, and the volume of Alaska gas regardless of the issue of one or two pipes.

In the context of the supply study scenarios, a volume of 2.5 to 2.75 Bcfd of Alaska gas was assumed and this level leaves room for up to 1.5 Bcfd of Mackenzie gas. Since no scenario contemplates a total volume of arctic gas of greater than 4.25 Bcfd, a volume in excess of 2.5 Bcfd from Alaska does suggest a risk to development of Mackenzie gas beyond that level. If a 4 Bcfd or large pipeline is built for Alaska gas, and that line is built first and separate, there is a substantial risk that Mackenzie development will be pre-empted and delayed beyond the timeframe of 2015. The recent plethora of LNG projects only adds to this risk.

Another possibility is that separate projects could proceed on similar timeframes. This could occur if the decision is for two pipelines and simultaneous commitments to proceed are made. This could present a situation with a total volume of 5.5 Bcfd entering the market. Such an eventuality has not been contemplated in any of the scenarios and would definitely have a depressing effect on prices beyond any levels in the scenarios.

Question 8: What changes, if any, would make a stand-alone Alaska LNG project delivering its product to the Asian market economic? What project development scenarios might make such a LNG project economic? Even if an Alaska project were economic, will there be competing sources of gas around the Pacific that would likely be able to beat the price an Alaska project would be required to charge?

CERA is addressing these issues currently as part of a multi-client study of world LNG markets, which the State of Alaska is participating in. If a more timely response is required, we will make every effort to address your issues separately. If desired, once the study is more complete, we could arrange a meeting with CERA's Asian and North American LNG experts to address the significance of the study findings for your questions.

Preliminary perspectives on the Asian market for LNG are provided in the following paragraphs, and these are followed by a comparison of shipping costs and distances from major suppliers to major markets in the Pacific basin. The term "train" refers to the liquefaction capacity of a given liquefaction unit. In Alaska's case the LNG sponsor group is considering two trains with an initial capacity 3.6 million tons per year, expandable to 7 million tons per year each. The volumes per train correspond to 480-500 MMcf (millions of cubic feet) per day, expandable to approximately 1.0 Bcf per day for each train. This is approximately the standard in international LNG markets. These shipping costs listed below illustrate the competitive position and challenges associated with moving Alaska LNG into Asian markets.

There is plentiful gas supply to East Asia in the current decade, and it will be a buyers' market for LNG for at least a decade. A number of countries are developing supply projects:

- Australia - the Northwest Shelf 4th train due for 2004, with a 5th train possible by 2007 (competitive against Alaska supply);
- Indonesia - adding another train at Bontang, seeking to develop a new supply project by 2006 at Irian Jaya (these will both beat Alaska economics);
- Malaysia - Developing a third LNG project at Bintulu, probably on line by 2004 (beats Alaska economics);
- Brunei - Opening up the upstream with an eye toward a adding a new train by 2007/8 (beats Alaska economics);
- Russia - looking to supply Japan and Korea with LNG from Sakhalin (likely very competitive economically against Alaska, and with Shell's marketing strength behind the project).

- In addition, there are projects in the Persian Gulf that are looking to supply East Asia, and which would likely prove competitive with Alaska.

The demand picture is far less certain, with a significant possibility that demand will prove disappointing. Liberalization of the power and gas industries in Japan and South Korea mean that the future demand for gas in both countries is highly uncertain. Japanese utilities have deferred a number of proposed gas-fired power projects in an effort to clean up their own balance sheets. As competitive pressure forces power tariffs down in the industrial sector, the utilities are being forced to cut capital expenditures. Competition with coal will only intensify as a result.

Political and economic uncertainty (globally) benefits the "secure" suppliers (Australia and potentially Alaska). The issue for East Asia is one of security versus economy. Historically, concerns about security of supply led to the willingness of Japanese buyers in particular to pay a premium for diversity of supply. A world with lessened political tensions, but more economic competition (globalization), will lower the willingness to pay that premium. A world of price competition but relative peaceful relations in East Asia is probably negative for Alaska, as it will see a strong competitive threat from Russian supply and will improve Indonesia's chances of financing new supply. A world of relative political instability in East and Southeast Asia will allow Alaska to market its gas as a secure supplier.

Preliminary results from CERA's LNG study comparing shipping costs and distances among existing and potential LNG supplies and markets in the Pacific basin are provided below. On these terms Alaska LNG is competitive shipped into Mexico, but would face challenging competition to Asian markets.

In addition to the shipping costs listed below, Alaska LNG would face upstream pipeline transport costs from Prudhoe Bay to Alaska's southern coast of approximately $0.70 or more, plus compression fuel (conservative estimate based upon capital costs of $2.4 billion for pipe, and throughput of 2.0 Bcf per day). This transport cost, added to shipping, would be subtracted from the netback price available to Alaska reserves, and does not include the capital associated with liquefaction facilities or ships.

Full Costs Transportation Tariffs
Pacific Basin
($/mmbtu)

	FROM:	Qatar	Malaysia	Indonesia	Indonesia	Australia	Russia	US	Bolivia	Venezuela a/
		RasGas	Bintulu	Tangguh	Arun	NWS	Sakhalin	Alaska	Arika	Trinidad
TO:										
Japan	Sodegaura	$1.01	$0.50	$0.42	$0.58	$0.61	$0.25	$0.62	$1.35	$2.02
Japan	Kagoshima	$1.73	$0.85	$0.80	$1.02	$1.11	$0.63	$1.24	$2.55	$3.33
Korea	Inchon	$0.96	$0.45	$0.42	$0.53	$0.60	$0.28	$0.72	$1.46	$1.96
Taiwan	Yung-An	$0.83	$0.32	$0.32	$0.40	$0.47	$0.35	$0.80	$1.52	$1.82
China	Pearl River	$0.81	$0.32	$0.36	$0.38	$0.49	$0.39	$0.84	$1.57	$1.80
India	Bombay	$0.30	$0.59	$0.70	$0.40	$0.63	$0.92	$1.44	$1.57	$1.53
India	Ennore	$0.43	$0.45	$0.56	$0.26	$0.52	$0.78	$1.28	$1.54	$1.48
Mexico	Rosarito	$1.67	$1.14	$1.00	$1.24	$1.22	$0.72	$0.45	$0.67	$0.85

Marginal Cost Transportation Tariffs
Pacific Basin
2006-2010
($/mmbtu)

FROM:		Qatar RasGas	Malaysia Bintulu	Indonesia Tangguh	Indonesia Arun	Australia NWS	Russia Sakhalin	US Alaska	Bolivia Arika	Trinidad
TO:										
Japan	Sodegaura	**$0.35**	**$0.22**	**$0.16**	**$0.21**	**$0.23**	**$0.11**	**$0.21**	**$0.47**	**$0.64**
Japan	Kagoshima	**$0.63**	**$0.44**	**$0.39**	**$0.45**	**$0.48**	**$0.35**	**$0.50**	**$0.86**	**$1.03**
Korea	Inchon	**$0.33**	**$0.20**	**$0.16**	**$0.19**	**$0.22**	**$0.12**	**$0.23**	**$0.49**	**$0.62**
Taiwan	Yung-An	**$0.29**	**$0.16**	**$0.13**	**$0.15**	**$0.18**	**$0.14**	**$0.26**	**$0.51**	**$0.57**
China	Pearl River	**$0.28**	**$0.16**	**$0.14**	**$0.15**	**$0.19**	**$0.15**	**$0.27**	**$0.53**	**$0.57**
India	Bombay	**$0.13**	**$0.24**	**$0.24**	**$0.15**	**$0.23**	**$0.32**	**$0.45**	**$0.53**	**$0.43**
India	Ennore	**$0.17**	**$0.20**	**$0.20**	**$0.11**	**$0.20**	**$0.28**	**$0.40**	**$0.52**	**$0.47**
Mexico	Rosarito	**$0.54**	**$0.41**	**$0.33**	**$0.41**	**$0.41**	**$0.26**	**$0.15**	**$0.24**	**$0.25**

Transportation Distances
Pacific Basin (miles)

FROM:		Qatar RasGas	Malaysia Bintulu	Indonesia Tangguh	Indonesia Arun	Australia NWS	Russia Sakhalin	US Alaska	Bolivia Arika	Trinidad
TO:										
Japan	Sodegaura	**6,637**	**2,498**	**2,286**	**3,461**	**3,623**	**952**	**3,386**	**8,983**	**13,585**
Japan	Kagoshima	**6,125**	**1,986**	**1,984**	**2,949**	**3,289**	**1,168**	**3,996**	**9,579**	**13,098**
Korea	Inchon	**6,302**	**2,204**	**2,361**	**3,123**	**3,610**	**1,251**	**4,079**	**9,771**	**13,276**
Taiwan	Yung-An	**5,351**	**1,236**	**1,557**	**2,173**	**2,617**	**1,777**	**4,605**	**10,218**	**12,321**
China	Pearl River	**5,159**	**1,170**	**1,855**	**1,980**	**2,726**	**2,095**	**4,922**	**10,558**	**12,184**
India	Bombay	**1,313**	**3,212**	**4,413**	**2,132**	**3,775**	**5,971**	**8,799**	**10,550**	**8,506**
India	Ennore	**2,340**	**2,180**	**3,382**	**1,100**	**2,949**	**4,939**	**7,767**	**10,358**	**9,963**
Mexico	Rosarito	**11,489**	**7,334**	**6,635**	**8,311**	**8,111**	**4,481**	**2,278**	**4,122**	**4,007**

Question 9: What are the possibilities of a GTL project in conjunction with an Alaska Highway gas pipeline or with the current taps line?

Gas-to-liquids (GTL) technology is emerging as a viable alternative to LNG and long-distance pipelines as a means of monetizing remote gas resources. Although the technology is not new, in recent years there has been growing interest driven by progress by a number of companies in reducing costs for the GTL process. Other factors such as growing concerns about flaring of remote associated gas and the environmentally driven tightening of fuel specifications have contributed to growing interest in the commercial application of GTL. As a consequence, a number of players are showing clear signs of intending to proceed with the development of commercial GTL projects, and it is likely that at least one or two projects will be developed and become operational in 2005–06. In CERA's view, if crude prices average in a range of $17 - $20 per barrel for WTI, a significant commercial GTL industry with productive capacity by 2020 of up to 2 million barrels per day could emerge.

Despite this potential emergence of a viable, global GTL business, GTL is unlikely to be a favorable option for the development of Alaska North Slope gas. A GTL project based on the North Slope would be at a marked cost disadvantage to many other regions with large remote gas resources. As a result, it is unlikely that developers will proceed with development of large-scale commercial GTL projects based on North Slope gas.

Although the basic chemistry of F-T synthesis has been known for over 75 years, high costs relative to the oil value chain have prevented the widespread application of the technology to the monetization of remote gas resources. However, significant research and development programs have continued. Since the mid-1990s, signs have been accumulating that advances in technology and a move to larger size plants are resulting in significant reductions in cost. For example, Shell has reported a 60 percent reduction in the unit capital cost of its Shell Middle Distillate Synthesis (SMDS) process since 1987. Conoco recently announced plans to build a 400 bpd plant to demonstrate advances in its syngas and F-T synthesis technologies.

As a result, the cost of liquids produced from GTL is falling. Based on current technology, the cost of a barrel of GTL output has fallen to approximately $17 – $20 per barrel, based on:

- All-in capital costs of $20,000 per barrel per day of GTL production capacity.
- Product yield of 1 barrel of GTL liquids per 8,500 Scf of feed gas.
- Operating costs of $4.00 – $5.00 per barrel.
- A feed gas cost of $0.50 per MMBtu.

Prices for GTL products will be closely tied to the prices of the corresponding refined products — naphtha, jet fuel, and diesel fuel. GTL producers can expect to realize a price premium to reflect the quality of GTL products, but this premium will be limited to reflect the marginal operating cost of refinery processing required to meet the relevant constraining specification, such as diesel sulfur content. With costs as outlined above,

the GTL process is economically if feed gas is available into the GTL plant at $0.50 – $0.75 per MMBtu.

Looking at the track record of other technologies, it is likely that further cost reductions in GTL could occur if several large-scale GTL plants are built, based on the experience gained from the design, construction, and operation of these first plants. GTL economics will remain highly dependent on the margin between the feed gas price and global oil prices. If oil prices average $12 - $15 per barrel (real terms) for WTI, or if the feed gas price into the plant is above $0.75 per MMBtu, GTL economics would be marginal. Hence under such a lower price environment, development of GTL plants would be limited and very slow unless significant further progress is made in reducing costs.

The GTL Opportunity in Alaska

Development of GTL projects based on the associated-gas reserves of the Prudhoe Bay field on the North Slope of Alaska have been under consideration for some time. However in CERA's view, GTL development on the North Slope is unlikely to be economically viable. The high capital, operating, and logistics costs associated with the location make other remote gas sites much more attractive candidates for GTL developments.

A number of factors have been cited supporting the development of GTL projects in Alaska, including:

- **Resource size.** The enormous gas reserves of the Prudhoe Bay field are more than sufficient to support multiple gas monetization options. Hence GTL can be considered in combination with the other options, including pipelines and LNG.
- **Existing infrastructure.** The TAPS oil pipeline has significant, and potentially growing, spare capacity. Hence no or very little investment would be required to transport output from a potential GTL plant on the North Slope to Valdez. GTL output could potentially extend the life of conventional crude oil production on the North Slope, if conventional production were to decline to the point that the minimum volume threshold for operation of TAPS was reached.
- **Market for clean fuels.** Diesel fuel specifications in the United States, and the State of California in particular, are among the tightest in the world, and are getting tighter. By 2007, on-road diesel fuel sold in the US will have to meet a 15 ppm sulfur specification. Valdez's relative proximity to the US West Coast could make this a potentially attractive market for Alaska GTL production.

However in CERA's view these benefits are insufficient to offset the factors working against the developments of GTL on the North Slope:

- **Plant capital and operating costs.** The harsh and remote arctic environment would significantly increase the cost of building, operating and maintaining a complex process facility such as a GTL plant on the North Slope, relative to many competing sites with remote gas resources. Given the importance of capital and operating costs to the overall economics of the GTL process, this would significantly penalize Alaska North Slope GTL projects versus competing projects.

- **Shipping costs.** The existing capacity in the TAPS system would obviate the need for investment to in pipeline capacity to transport North Slope GTL production to tidewater. However the GTL project would presumably have to pay TAPS tolls. Further, the Jones Act would require the shipment of GTL products from Alaska to the US West Coast to take place in higher cost US-built, -flagged and -crewed vessels. The total logistics costs for a GTL plant on the North Slope would likely be least $1 - $2 per barrel higher than for most other sites being considered for GTL development.
- **Segregation capability in TAPS.** The high quality GTL products must be segregated from other, potentially contaminating hydrocarbon streams in order to achieve maximum potential value. If TAPS does not currently have the capability to provide such segregation, this would further penalize the economics of a North Slope GTL plant. This penalty would take the form of either higher costs required to pay for the capability to segregate, or lower netbacks caused by downgrading if GTL products are blended into the ANS stream.

Question 10: If Alaska gas moves into the Canadian pipeline system in the next 7-10 years, will there be sufficient capacity in the Canadian pipeline system to deliver Alaska gas to American markets? If new "take away" capacity from Alberta is required to accommodate arctic gas, is there any reason to believe the toll charged to use that new capacity would be materially higher than the toll charged the already existing capacity?

Pipeline capacity from Alaska to Alberta *must* be accompanied by an equal amount of additional capacity from Alberta to markets in the US. Supply growth in Western Canada will not only meet Canadian demand growth but will fully utilize (and likely require some expansion) of the existing infra/structure before any arctic gas begins to flow.

Since all existing export pipelines out of Alberta will be fully utilized, an increase in current tolls is likely on the majority of the pipes. Timing is important since the levels of expandability do result in different levels of cost. Generally, FERC only allows expansion costs to be rolled in existing rates if the change is a very small increase. If an expansion would push existing tolls beyond that point, the expansion is given "incremental rates" attributable to that expansion. However, rather than assign the cost of expansions to any source of supply, the table below indicates the volume-weighted average cost of expansion to accommodate WCSB growth as well as up to 4 Bcfd of arctic gas. This average cost assumes L-48 demand growth will require additional supply both along the West Coast and in the Midwest, the natural markets for Canadian and arctic supply.

First level of expandability

Pipeline	Volume (mmcfd)		Expansion ($/mcf)
PGT	500		0.45 - 0.50
NBPL	300		0.45 - 0.50
TCPL	500		0.75 - 0.80
Alliance	1000		0.80 – 0.85
Subtotal	2,300	Average	0.67 – 0.70

Next level of expandability

To Midwest	1,500		0.90 - 1.00
To West Coast	2,100		0.70 - 0.80
Subtotal	3,600	Average	0.78 - 0.88
Total expansion	5,900	Average Toll	0.74 – 0.81
IntraAlberta Portion			0.20 – 0.25

Total Estimated Toll Arctic / Alberta terminus to Market: 0.94 – 1.06

The first level of expandability involves compression and in some instances looping (addition of pipe in areas of high pressure drop). Once this "cheaper" expansion is exhausted, more and more pipe has to be added until the system is at its maximum economic operation. At that point the alternatives are a new pipeline or "twinning" of an existing system. Twinning can be considered a total looping or the building of an additional line using the same right-of-way and existing infrastructure and as such will always be less expensive than a new greenfield pipeline. To arrive at the volumes required, it is likely that extensive looping and some twinning will be required.

This indicates that the tolls from Alberta to the Pacific Northwest and California will be higher than existing rates, but lower than tolls to the Midwest. The tolls to the Midwest will be higher than existing Northern Border Pipeline rates, but will be comparable with the current Alliance and TransCanada tariffs.

Question 11: Assuring local uses

<u>Question 11, Part 1</u>: In the development of a gasline project, how have other states/nations assured access to gas for local communities and value-added processing opportunities?

This question would require a major study effort of comparative distribution franchise practices, and is generally beyond the scope of CERA's work.

The most obvious and recent example is mentioned earlier in this document and that is the experience in Nova Scotia. After winning the distribution rights in the province, Sempra has announced a dramatic reduction in the economic ability to provide local services.

<u>Question 11, Part 2:</u> How do we ensure sufficient capacity in the pipeline or ability to expand capacity to allow for future additional gas throughput, particularly for future in-state uses, without jeopardizing the economics of the project?

If sufficient commercial interests exist within Alaska to support pipeline capacity dedicated to in-state deliveries, then experience in other markets indicates that those interests have proven willing to pay for such capacity. If not, then it is a matter of direct state subsidy. A bid ("open season") process usually establishes commercial interest in pipeline capacity. Similarly, the state could solicit interest in bids for distribution franchises. The potentially low market value of gas and moderate transmission costs could be favorable factors to the economics of distribution, with negative factors of terrain, permafrost and low population density adversely affecting the delivered cost.

Pipelines are usually designed with expandability in mind, but system design always involves a trade-off between initial costs (which may be minimized if more compression is used) and future expandability (which may be greater if less compression and larger pipe is used initially). The producers are the likely drivers of this decision. If there is significant potential for future growth in productive capacity, then producers are likely to ensure some expandability, especially in a project of this magnitude. If the initial cost burden is too high, then the willingness by producers to pay for future expandability may be lessened.

The state can support the economics of the project by paying a fair and objective rate for capacity to deliver within the state, and offering to help with the possible cost burden associated with ensuring future expandability to markets within the state. Again, while the state should not use long-haul capacity for in-state deliveries, nor should it pay for capacity costs beyond the Alaska delivery points.

Questions 12 and 13: Financing and ownership

Question 12: How will the gasline most likely be financed? Can the state play a constructive role in the efforts to finance the pipeline project? Should the state seek to ensure that the pipeline be financed in some particular way?

Your attorney in Washington DC, Robert Loeffler of Morrison and Foerster, called to ask for recommendations of investment bankers to deal with these questions. I referred him to two organizations:

1) Petrie Parkman in Houston – Bill Garner. This investment bank specializes in the energy industry, and specifically is probably the leading specialist in supply deals. As such, they should be quite competent to advise the state on the benefits or drawbacks of varying financial arrangements.

2) The Riverstone Group in New York. This group was formed by David Lucien from Goldman Sachs, Doug Mackenzie from both Morgan Stanley and Goldman Sachs, and includes Pierre Lapeyre, also from Goldman. David and Doug were energy and gas practice leaders within their organizations, and Pierre worked with gas industry clients as well.

These individuals and companies should be able to provide quality services and advice to the state.

Question 13: Should the state be a part owner of an Alaska Highway gasline project? What economic advantages would there be if the state were to assume an ownership interest in a gasline?

Benefit to the state from ownership in the pipeline would be limited. Ownership might include a small level of influence and information regarding the development process but even this is doubtful. Although we have not approached these producers directly with this issue, generally from most producers' and pipeline developers' perspective government participation and involvement would be a complicating factor that could impede and slow the process. Since there is no inherent benefit, CERA's recommendation is that Alaska avoid direct ownership interests in the pipeline. If such participation would be beneficial, it would be best undertaken at the request of the producers.

We hope that this memo supports those areas in which CERA is able to be of help, and those for which we will help with references. CERA stands ready as part of its relationship with the state of Alaska to provide presentations or conference calls relating CERA's LNG and supply multiclient studies to your specific issues, or in other areas which the state might deem helpful. We look forward to continuing our relationship, and hope to see you again soon.

Sincerely,

Edward M. Kelly
Director of Research
North American Natural Gas
Cambridge Energy Research Associates

Ed Small
Director, Canadian Energy
Cambridge Energy Research Associates

Enclosure

Alaska Highway Natural Gas Policy Council
COMMITTEE STRUCTURE

Council Mission: To promote an Alaska Highway Natural Gas Pipeline project to the lower 48 that also enables creation of a natural gas business in Alaska.

Alaska Hire/Buy/Build – Mike Navarre, chair
Jerry Hood, Rhonda Boyles, Rosemarie Maher, Jake Adams, Peg Tileston

- Use of the Alaska labor pool by contractors and subcontractors
- Use of Alaska businesses
- Training and readiness of Alaskans for jobs on a gas project
- Socio-economic impacts

State Pipeline Ownership and Tax Structure – Bill Corbus, chair
Dave Rose, Ron Duncan, Grace Schaible, Mike Navarre, Ed Rasmuson, Mike O'Connor, Ken Thompson

- State promotion and facilitation of project financing – state ownership
- Evaluation of state tax structure

Federal/International Action – Charlie Cole, chair
Esther Wunnicke, Bob Penney, Jon Rubini, Jeff Feldman, George Wuerch

- Federal permitting/access
- Federal agency lead
- Canadian permitting/access
- Other contractual considerations
- Domestic markets – competing sources/sharing of the market
- Canadian national and territorial relations

Access for in-state gas use and future opportunities– Ken Thompson, chair
Carl Marrs (vice chair),Rosemarie Maher, Rhonda Boyles, Al Adams, Brian Davies, Jim Jansen, Jerry Hood, Bob Penney, Jack Roderick, Lee Gorsuch, Jeff Feldman, George Ahmaogak

- Supply/demand for in-state natural gas
- Best practices valuation/net-back pricing methodology to facilitate in-state gas use
- Ensuring fair and transparent access rules to natural gas for Alaskan customers
- Benefits of natural gas development to rural Alaska and to communities along the pipeline
- Future options over 50 years for projects utilizing: gas-to-liquids (GTL), liquefied natural gas (LNG), natural gas liquids (NGL), petrochemical feedstock, fertilizer, etc. for in-state use or for export to markets in Asia or the West Coast
- Promotion or attraction of investment for in-state distribution and value-added processing
- Assess costs and benefits of the State taking delivery of its royalty share vs. taking royalty payments; review other states' policies for best practices

Environmental Considerations– Peg Tileston, chair
Brian Davies, Esther Wunnicke, Lee Gorsuch, Grace Schaible

- Environmental impacts and necessary protection measures
- Doing it right

Revised 06/22/01

Subject: Purvin & Gertz Report Entitled "Alaskan Gas Development Strategies"
Date: Tue, 10 Apr 2001 16:46:42 -0800
From: Jeff Lowenfels <jeffl@ypc.com>
To: Highway Gas Policy Council Members

April 10, 2001

Dear Highway Gas Policy Council Member:

Attached is a seven-page paper prepared by Yukon Pacific Corporation in which we challenge and correct several core assumptions regarding the LNG alternative examined in the Purvin & Gertz report entitled "Alaskan Gas Development Strategies". This report was distributed to a number of paid subscribers and sponsors (including the State of Alaska, several legislators and many private companies) last year and has been cited publicly on a number of occasions following its release.

Since Yukon Pacific was not a subscriber (nor, incredibly, were we ever consulted by Purvin & Gertz in the course of their work on this report in connection with any of the unique characteristics of a North Slope-sourced LNG project which are the subject of our attached paper), we have only recently reviewed this document and had an opportunity to analyze it and compile these comments. This is extremely unfortunate because we believe that the report was relied on by the Governor and his staff to conclude that "My Way is the Highway." As you will see, had the true numbers been included, this might not have been the case.

I know you will find a few minutes to read the attachment to this email. After doing so, please feel free to contact me or my staff with any questions you may have. We are quite convinced that our numbers for OUR project are the most exact and correct available and should be used when analyzing the results of the Purvin & Gertz report.

We sincerely appreciate the time and effort you are devoting to this vital issue. In particular, I want to thank you for inviting me to speak to your group last week on behalf of YPC. I hope my remarks were useful to you and the essential work the Governor has asked you to do.

Sincerely,

Jeff Lowenfels,

President and CEO

Yukon Pacific Corporation

CONFIDENTIAL

The following comments have been prepared by Yukon Pacific Corporation following an extensive review of a confidential report authored by Purvin & Gertz, Inc. (P&G) entitled "Alaskan Gas Development Strategies". The remarks offered and changes proposed below refer to numbers, assumptions and values in the Purvin & Gertz document that are confidential and are provided for the purposes of internal review of the report.

Summary

This analysis shows that several important elements used in the P&G evaluation of the North Slope-sourced LNG project alternative should be changed to properly reflect the potential for a *much higher* netback value (over $1.00 per million Btu, nearly 5 times greater than the $.22 figure used) to Producers and the State of Alaska. These changes are discussed in detail below and involve incorrect assumptions in the P&G report relating to projected LNG prices in Japan, LNG plant operating costs, LNG plant capital recovery costs and pipeline cost of service. ***Except for the issue of projected LNG prices in Asia, this occurred because of P&G's misapplication of "generic" LNG project design and cost factors in its analysis rather than employing the innovative design efficiencies and resulting cost savings benefits unique to the permitted TAGS LNG project.***

Among other gas commercialization alternatives analyzed in the report, P&G assesses the potential netback for a new, generic, world-scale LNG export project requiring an 800 mile natural gas pipeline from the North Slope to a production facility and marine terminal located on the south shore of Alaska. P&G reports the following values, again, for a generic LNG project (Figure VII-18 on page VII-23):

	$/mmbtu
1.) CIF Japan price	3.34
2.) Marine transport	0.65
3.) LNG plant operating costs	0.40
4.) LNG plant capital recovery costs	0.93
5.) Pipeline cost of service	1.14
Producer netback	**0.22**

A. LNG economic analysis

Using the above factors with "corrected" (and most definitely CORRECT) information produces considerably different and *far more positive* results for the Producer (and State) netback for the Alaska LNG project.

1.) CIF Japan price

P&G's projected prices for LNG appear to be low.

The $3.34/mmbtu is the "lower tier price" per P&G. The table entitled "FORECAST DELIVERED LNG PRICE TO JAPAN, EXISTING CONTRACT INDEXATION (2000$)" (page VII-10) shows the following (note: JCC is the abbreviation for "Japan Crude Cocktail"):

Year	2000	2005	2010	2015	2020	
JCC, $/bbl	26.79	20.95	19.40	19.18	19.15	
LNG $/mmbtu	3.82	3.37	3.32	3.31	3.30	
BTU parity $/mmbtu	4.58	3.58	3.32	3.28	3.28	at 5.85 mmbtu/bbl

The JCC $/bbl are lower than the crude oil forecast of the US Department of Energy, EIA published in their AEO 2001 report. Perhaps some further review of world oil price forecasts would be beneficial.

Data from the Sumitomo Corporation shows that LNG price exceeded JCC price (on a $/mmbtu basis) from 1987 through the beginning of 1999. The P&G chart on page VII-10 shows that they analyzed LNG prices during the year of 1999 during which world energy prices increased dramatically. Their analysis thus reflects atypical conditions.

P&G correctly notes that LNG prices are generally indexed to oil price. However, only some of the contracts index immediately with changing oil prices. Those contracts with a delayed indexing would tend to slow the rate at which LNG prices would catch up with a change in oil price. P&G does not address this lag in LNG price indexing, thus one would expect the LNG price determined per their analysis for 1999 to be too low.

The above data shows that the $3.34/mmbtu "lower tier price" used by P&G is actually closer to the oil btu parity price. Based upon P&G's oil price forecast, an LNG price more representative of current and historical LNG pricing would be $3.72/mmbtu (112% of Btu parity $3.32/mmbtu). P&G uses the $3.34/mmbtu "lower tier price" as the base price for reporting the economics for an LNG project. The low sensitivity LNG price (pages VII-24 and VII-25) is 90% of their "lower tier price".

P&G (page VII-12) develops an "upper tier price" that they report in their report (page VII-13). The high sensitivity price (pages VII-24 and VII-25) is the average of the "lower" and "upper" tier price ($3.61/mmbtu).

The following ranks the respective LNG prices in $/mmbtu.

P&G low sensitivity price	$3.00
P&G lower tier price	$3.34
P&G economic report for LNG	**$3.34**
BTU parity with P&G oil price	$3.34
P&G higher sensitivity price	$3.61
Est. LNG price historical per Sumitomo	**$3.74**
P&G upper tier price	$3.89

Adjusting the P&G economic analysis to reflect the historical relationship between delivered LNG prices to Japan and JCC and using P&G value for JCC produces the following result:

	$/mmbtu	change
CIF Japan price	**3.72**	**+0.38**
Marine transport	0.65	
LNG plant operating costs	0.40	
LNG plant capital recovery costs	0.93	
Pipeline cost of service	1.14	
Producer netback	**0.60**	**+0.38**

2.) Marine transport

P&G assumes use of 137,500 CM tankers at $200 million each (page VII-20). P&G assumes one tanker per 1 MTA of LNG production. These assumptions are essentially the same as YPC.

3.) LNG plant operating costs

The P&G includes fuel in their plant operating costs. They give credit for colder ambient air in Alaska and reduce the fuel from 10% typical of an equatorial plant to 8% (Page VII-18). They did not go far enough however to reflect the benefits of high pressure low temperature feed to the plant. The following is a summary of fuel for various plants:

Typical equatorial	10-11%
P&G Alaska	8%
YPC with 2200 psi pipeline (Bechtel 1991)	6%
YPC with 2600 psi pipeline (KBR 2000)	4%

The YPC data is based upon heat and material balances provided by Air Products and Chemicals Inc. with minor engineering adjustments by Bechtel and Kellogg, Brown & Root. YPC's numbers are sound.

YPC designed the pipeline using our thermal-hydraulic simulation software and chose a high operating pressure that, for a number of reasons, minimized frost heave and thaw settlement concerns. Since we condition the gas on the North Slope there is no need to drop the pressure from the pipeline to liquefaction. Liquefaction efficiency and thus fuel vary with the inlet pressure to the plant. We took advantage of the higher pressure and optimized the LNG plant to improve the thermal efficiency.

I believe P&G used a 2200 psi pipeline design. They should reduce their fuel consumption to at least 6% in order to be consistent with their premises for the pipeline. YPC would use 4% fuel consistent with our design.

The premise used by virtually every party looking at a North Slope-sourced LNG project is that a single owner will purchase gas at the North Slope and sell LNG FOB Valdez. Incremental economics regarding fuel consumption are thus based upon North Slope price. Typically, operating costs for the project are reported as non-fuel values with fuel costs are determined as the difference in BTUs sold versus purchased.

P&G says that fuel is a "major" expense. We don't have line item details of their operating costs. Assuming that "major" translates to "more than half", let's assume that fuel is 60% of the P&G operating costs of $0.40/mmbtu. Reducing the fuel from 8% to 6% would reduce the operating expense by $0.06/mmbtu [$0.40*60%*(8-6)/8].

Adjusting the P&G economic analysis to reflect 6% fuel produces the following result:

	$/mmbtu	change
CIF Japan price	**3.72**	**+0.38**
Marine transport	0.65	**0.0**
LNG plant operating costs	**0.34**	**-0.06**
LNG plant capital recovery costs	0.93	
Pipeline cost of service	1.14	
Producer netback	**0.66**	**+0.44**

4.) LNG plant capital recovery costs

In the year 2000, YPC developed capital costs for the LNG plant and marine terminal based upon our new high pressure design. The excavation and plot plan were developed for YPC by Michael Baker, Jr. The heat and material balances were developed by APCI. CBI provided a design and cost for the LNG tanks. Moffatt & Nichol developed the design and cost estimate for all marine facilities. KBR developed the design of the liquefaction plant (based upon the APCI balances), utilities and other attendant facilities based upon their database of costs for other base load LNG facilities. KBR rolled all of the costs together in a turnkey estimate of a 2 train (9.2 MTA), 3 train (13.8 MTA) and 4 train (18.4 MTA) facility. The KBR estimate includes contingency for a 75% probability of cost under run. YPC added costs for owner management of the project.

The cost of a YPC's 9.2 MTA and 13.8 MTA liquefaction plant and marine terminal scenarios in US2000$ are $2.3 and $3.1 billion respectively. P&G's estimate for a 14 MTA facility is $5.3 billion.

YPC estimate for a 14 MTA facility is 42% less than P&G's estimate. Again it must be noted that P&G's design is based upon a fuel consumption twice that of YPC's (8% vs. 4%). One would expect the P&G design to cost more since there is twice as much fuel consuming equipment.

The following reflects a somewhat arbitrary adjustment of the P&G capital costs for the LNG plant referenced to YPC's costs using a ratio of 6% fuel to 4% fuel (42% * (1-0.33) = 28% less):

	$/mmbtu	change
CIF Japan price	**3.72**	**+0.38**
Marine transport	0.65	**0.0**
LNG plant operating costs	**0.34**	**-0.06**
LNG plant capital recovery costs	**0.67**	**-0.26**
Pipeline cost of service	1.14	
Producer netback	**0.92**	**+0.70**

5.) Pipeline cost of service

On page V-21, the following COS in $/mmbtu are reported for a pipeline from Prudhoe to the south shore (Valdez):

BSCFD	COS	
0.8	0.8	1.27
1.0	1.0	1.14
1.6	1.6	0.84
2.0	2.0	0.76
3.0	3.0	0.72

The pipeline cost of service reported in the economics is for 1.0 BSCFD, however, the LNG plant COS reported is for 2.0 BSCFD (approximately 14 MTA). P&G notes that the flow ramps up from 1 to 2 BSCFD. Using the COS for a 1 BSCFD scenario for a project ramping to 2 BSCFD is very conservative.

P&G does not have a pipeline COS for a ramp-up scenario. Perhaps some value between the COS for a 1 and 2 BSCFD scenario should be used in the economics. The following reflect the P&G economics adjusted (somewhat arbitrarily) for a pipeline COS ramped from 1 to 2 BSCFD [0.95 = (1.14 + 0.76)/2]:

	$/mmbtu	change
CIF Japan price	**3.72**	**+0.38**
Marine transport	0.65	0.0
LNG plant operating costs	**0.34**	**-0.06**
LNG plant capital recovery costs	**0.67**	**-0.26**
Pipeline cost of service	**0.95**	**-0.19**
Producer netback	**1.11**	**+0.89**

6.) Alaska income tax

P&G assumes a 9.4% income tax rate for Alaska. The oil companies use worldwide accounting that reduces their effective Alaska income tax rate to about 3.6% in 1999. Assuming international oil company ownership of all or part of the facilities, the tax of an Alaskan project appears overstated by 5.8%. Obviously, this would not apply to a Canadian project.

B. Summary on economics for the LNG alternative

P&G's approach was to apply a consistent set of criteria to various gas project options to generate comparative economics. It appears that their economic comparison was done to assess the relative merits of the project as opposed to endorsing the viability of any one project.

The above analysis shows that combining the P&G analytical approach with YPC cost estimates and view of market pricing would result in a LNG project netback price in excess of **$1.00/mmbtu**. ***This netback is higher than any of the pipeline options to the lower 48 states***. This value exceeds the value YPC considers as a probable wellhead value and is somewhat suspect.

The assumptions used by P&G differ significantly from those used by YPC for the TAGS project. It is possible for people to have different opinions. P&G should consider reviewing their assumptions regarding LNG for the following reasons:

1 – Their capital cost estimate for the LNG plant and marine terminal is significantly larger than estimates produced by the licensor of the process technology used in over 80% of the worldwide base load capacity (APCI) in conjunction with an EPC firm that designs and builds LNG plants (KBR).

2 – P&G did not complete a cost of service for a pipeline ramping up to a design volume of 2 BSCFD (14 MTA). Use of the COS for a 1 BSCFD is a very conservative assumption. Any gas project from Alaska, whether overland or LNG, will have to ramp-up to the market entry volume within 2 years. P&G assumes quick or instantaneous ramp-up of the overland pipeline options (i.e., 4 BSCFD scenarios). On page II-1 P&G acknowledges that unless the LNG project is "piggy-backed" with another project, the LNG project must be massive in order to reduce the unit gas transportation costs. Uniform application of P&G's premises does not support use of a COS for a 1 BSCFD line for the LNG option.

3 – P&G's use of an LNG price at BTU parity with oil is not supported by historical data regarding LNG imported to Japan. Recognizing that people can differ regarding speculating about the future, it still seems reasonable to set the base economics at the historical condition (i.e., 112% of BTU parity with oil) then complete a sensitivity analyses above and below the base. P&G's price in the higher sensitivity case is less than the historical base condition experienced in the LNG market. It seems overly pessimistic to run all economics below the historical average condition especially since worldwide gas demand appears to be dramatically increasing (i.e., low cost of gas turbine combined cycle plants, quick installation time of these plants and environmental benefits regarding energy produced per molecule of CO2 released).

C. Piggy-backing LNG with GTL

P&G recently issued work regarding piggy-backing an LNG project with a GTL project located on the south shore of Alaska. Unfortunately, this scenario is not included in their report of Alaskan gas pipeline options. Piggy-backing LNG with GTL will not only reduce the unit transportation costs, but will increase the throughput per unit of installed capital for the LNG. The liquefaction plant can be designed for an extended end flash with the flash gas going to the feed of the GTL plant. This will reduce the specific horsepower (Hp per unit of LNG produced) and increase the efficiency of use of capital expenditure.

D. Asia Pacific LNG Supply and Demand

P&G shows that there is sufficient incremental demand for a 14 MTA LNG project from Alaska. However, the P&G values for incremental demand are less than those of YPC, Standard & Poors DRI, and Tokyo Gas.

Our Gas, Our Future

Dear Gas Policy Council Member: April 3, 2001

We appreciate your willingness to devote your time and energy to the issue of our huge North Slope gas deposits. You have chosen well: This is one of the most important issues Alaskans will ever confront.

As we see it, your primary challenge is to decide which is the best option for Alaska's gas. Here, our State Constitution is helpful: "Alaska's resources must be utilized, developed, and conserved for the maximum benefit of Alaska's people." (Article VIII, Sec. 2.) Fortunately, there also seems to be a consensus on the evaluation criteria: revenues for Alaska, gas for Alaskans, and jobs for Alaskans. More good news: There's probably no need to make a tradeoff between maximizing one of these outcomes at the expense of another.

Our Gas, Our Future thought the attached analysis detailing impediments to overland pipelines might prove of interest. Since the attached document was completed, several announcements have made piping gas to the U.S. all the more unlikely: Phillips and Chevron intend to put a combined 9 million tons of Australian LNG into California. BP intends to liquefy Egyptian natural gas, possibly for export to the U.S. East Coast. Then there is word of a major new gas find in Wyoming. Yesterday, BP announced plans to build three LNG import terminals in the U.S. and Shell announced plans to put Asian LNG (possibly from Sakhalin which they are jointly developing with Exxon) into California and Western Mexico. These are our markets! In other words, the U.S. market looks more and more like a box canyon where hopes for a gas project will die a long and agonizing death.

The Governor asked you to complete your work by November. These recent announcements suggest that November may be too late; today's markets evaporate tomorrow. This is as true in Asia, where some 9 projects are vying for the market, as it is in the U.S. And this "you snooze, you lose" situation is precisely why the Council must unshackle itself from constraints encoded in its name and determine what's best for Alaska, post-haste. Fortunately, this is well-trod ground. For starters, we'd recommend Backbone's January 2001 report, "Alaska's Gas, Alaska's Future."

Should you have any questions or comments, please do not hesitate to contact us. Our Gas, Our Future stands ready to assist the Gas Policy Council in its deliberations in any way we can, because our gas is our future.

Sincerely,

Scott R. Heyworth, Director

PO Box 100531 Anchorage, AK 99510 ◆907 277-9981 ◆info@alaskagaspipeline.org www.alaskagaspipeline.org

Impediments to an ALCAN Gas Pipeline

I. Alaskan Issues

Alaska's Constitution requires Alaska's resources to be developed for the maximum benefit of Alaska's people. In the case of North Slope natural gas, this means developing it in such a way that maximizes revenues for the state and Permanent Fund, that makes gas available to the maximum number of Alaskans, and provides the maximum number of jobs for Alaskans. The group Backbone's recent study strongly suggests that the LNG export option meets all three of these criterion, while the Alcan and over-the-top proposals clearly do not. Instate gas use is especially important, given Cook Inlet's impending shortage. According to a report by ISER, UAA's Institute of Social and Economic Research, absent a new source of inexpensive clean burning natural gas soon, Southcentral Alaska's economy will be crippled.

North Slope natural gas is Alaska's last, big, untapped available hydrocarbon asset. Delivered to Japan or the lower 48, our North Slope gas is worth $100-200 billion. Most of that value will be derived from transportation. Therefore, if Alaska wants to maximize revenue from the gas, it will have to own the transportation system. This will be difficult or impossible with a project running through Canada. State ownership is only an option with an all Alaskan project like the LNG project. State ownership could pay huge dividends to Alaskans, the gas owners, because public ownership enables the LNG project to avoid federal corporate income taxes. This tax holiday could save $1Billion per year, money that could help fuel state government and the Permanent Fund throughout the 21st century.

II. Producer Issues

The motives of the producers and their commitment to marketing North Slope gas are questionable. One would assume that if the producers were really serious about an Alcan project, they'd work closely with the existing permit holder, Foothills. Instead the producers ignore Foothills, and worse, threaten the company with bankruptcy. The producers announced a $75 million gas project study that sounds impressive but may be little more than a public relations exercise. This was the case with their similarly ballyhooed and priced LNG options study begun with much fanfare in 1998 and never finished.

Many observers believe that the producers will gin up figures showing huge cost savings for the North Slope offshore option over the Alcan. The thinking is that the producers will then use these figures in an attempt to extract fiscal concessions from the state and U.S. and Canadian governments. Is this just paranoia? No, it's standard operating procedure; and the companies have suggested that this is their plan.

Though largely unknown until recently, it is now common knowledge the 1991 Prudhoe Bay Issues Resolution between the units leaseholders (primarily Arco, BP, and Exxon) essentially prohibited gas sales prior to 2005. The impediments included a trigger mechanism whereby a gas sale would allow BP to call in billions of dollars of paper debt from Arco and Exxon for gas borrowed for infield use (fuel and enhanced oil recovery). Also the 1991 agreement guaranteed BP's right to veto gas sales prior to 2005. Finally, a gas sale would trigger a reallocation of operating costs at Prudhoe Bay directly onto Arco and Exxon, the largest gas owners, precisely when their capital costs had just gone up.

According to the Knowles Administration, the unitization of Prudhoe Bay aligned oil and gas ownership and eliminated impediments to gas sales. Unfortunately, these agreements have not been

finalized and are not yet public. So, there may well be institutional impediments to gas sales. Indeed, some observers believe Phillips Petroleum's repeated referrals to gas sales in the year 2007 suggest strongly that the new agreement establishes new impediments.

So what drives the producers' so-called study? Greed and fear. As for the greed,... Gas handling facilities at Prudhoe Bay are currently at capacity, therefore limiting oil production. The producers would like to remove this limitation, but investing in more gas handling capacity for a rapidly declining field makes no economic sense. As for the fear,... A bigger driving force behind the producer's theoretical enthusiasm for gas is the increasingly chilly political climate in Alaska. Alaskans and their elected representatives are tired of being manipulated and short-changed by the oil companies. Recent evidence of this falling-out is everywhere. It includes talk of:

- Eliminating the ELF tax
- Establishing a reserves tax on gas to provide the companies with an incentive to start marketing the gas; House Bill 190 introduced March 19 by Rep. Whitaker R-Fairbanks.
- Canceling of gas leases for non-performance, and
- State ownership of the gas transportation system.

As if the above weren't worry enough, the producers are struggling to keep Alaskan gas out of the Asian market until they have placed their Russian and Indonesian gas there first. With lower 48 gas prices at an all-time high and dissatisfaction in Alaska growing by leaps and bounds, the producers know they have to look really, really, really, really serious about marketing Alaska's gas or there nearly free ride will end abruptly. All evidence suggests they may be right.

Still more revealing is the recent announcement by Phillips that while saying for years that there is no market for LNG gas from Alaska (a distance of 2000 miles to our West Coast) Phillips is entering an agreement with El Paso Gas to ship 5 million tons per year to our West Coast from their holdings in Australia (a distance of 7,000 miles!). If Alaska had a 5 million ton contract with El Paso to our own West Coast and a 4 million ton contract with any Asian country, that total of 9 million tons per year immediately makes an LNG project to Tidewater in Valdez ***viable immediately.***

III. Practical, Technical, and Legal Impediments

There are other impediments to an Alcan project, starting with the size necessary to make it economic. U.S. and Canadian laws and treaty specify a maximum daily volume of 2.5 Bcf. Current calculations suggest, however, that, in order to be economic, the Alcan project must move at least 4.0 Bcf of natural gas per day. If true, this would dictate raising the allowable daily volume to at least 4.0 Bcf/day. While simple from a design point of view, these changes will be extremely difficult to bring off politically.

To begin to understand the political obstacles, one needs to recognize that 4.0 Bcf/day is a huge volume of gas, roughly equivalent to 20% of the current lower 48 U.S. demand. Even if it were economical to build the pipelines necessary to move this gas to the U.S. markets, the huge volume of new supply would depress the cost of natural gas in the U.S. But there is a practical problem as well: 4.0 Bcf/day exhausts proven North Slope gas reserves in 24 years. If the producers were allowed to ship the 6.0 Bcf per day that they'd like because the economics are better, they would exhaust proven North Slope reserves in a mere 18 years.

IV. Canadian Issues

Assuming that the supply and cost obstacles could be overcome, the Alcan gas line faces other obstacles as it moves south. The Southern part of the Alcan system, a y-line from Caroline, Alberta

west to California and east to Chicago has long since been built and is filled with Canadian gas. Existing U.S. Canada treaties provide that Alaska gas has preference over Canadian gas in the pre-build. It's unlikely, however, that Canadian gas producers and their elected champions will voluntarily remove their Canadian gas from the line--as required by law--so that Alaskan gas can displace them from the market place. Alcan project advocates argue that the newly completed Alliance pipeline has 2 Bcf of excess capacity. That may be true today, but it almost certainly won't be true in 18 to 24 months when a slug of new Canadian gas starts moving to market.

This is where economic and political obstacles combine. The 4.0 Bcf would displace more than 80% of the combined increment of new Canadian and new lower 48 gas expected to move into the market in the next ten years. Self-interest will force Canadian and Lower 48 gas producers and their elected representatives to block any efforts to change existing Canadian and U.S. law and treaties. Meanwhile, a huge new field (estimated reserves of 50-100TCF, roughly the size of total estimated North Slope reserves) is expected to start moving some 3.0 BCF flow into the U.S. Northeast in the next three to four years, several years at the very least before an Alcan project could be built.

In this regard, it's worth noting that the last time Alaska tried to move its gas down the Alcan, Canadian producers helped kill the project by lowering their prices. Furthermore, supplies closer to market (lower 48, Nova Scotia, Alberta, and even the Mackenzie R. fields) will always be cheaper to place in the market than gas from Alaska's North Slope because transportation costs will always be lower. In other words, gas more proximal to lower '48 markets will always be able to undersell gas from Alaska's North Slope.

V. Other Lower 48 issues

New gas from the lower 48 and more proximal areas of Canada and Mexico will soften the U.S. domestic market, causing prices to plunge. In the lower 48, natural gas is a commodity, traded on the spot market, with short-term contracts. This contrasts with the situation in Japan, which has no indigenous hydrocarbons and secures its energy future with long-term contracts, running 20 to 30 years. The lack of long-term contracts in the U.S. market makes the $10-12 billion required for a pipeline to Caroline Alberta-to say nothing of an additional 1500 miles to a market--a risky investment. The investment becomes even riskier given that the U.S. government expects the current Canadian and U.S. drilling frenzy to satisfy demand in the lower 48 for the next 20 years. Current federal supply estimates do not even include the large amounts of new gas available from the Gulf of Mexico.

VI. Conclusion

Given all of the above, it's not surprising that the producers and Alaska have not built a gas pipeline in the last 25 years. Fortunately, Alaska appears to have another better option: the all-purpose, all-Alaskan, LNG export project. **The question before the Gas Policy Council is: Which option is best for Alaska? To answer that question, the Council must thoroughly and fairly examine all the options.**

Scott Heyworth

Alaska Highway Natural Gas Policy Council
Workshop II Agenda

Thursday, April 5, 2001
Anchorage Sheraton Hotel – 10:00 a.m. to 5:30 p.m.

I. Call to order/opening remarks, 10:00–10:30

II. Presentation from Alaska Gasline Port Authority, 10:30-11:15

III. Presentation from Foothills Pipe Lines Ltd., 11:15-12:00

IV. Lunch break, 12:00 –12:30

V. Presentation from LNG Sponsor Group, 12:30-1:15

VI. Presentation from Yukon Pacific Corporation, 1:15-2:00

VII. Council Business, 2:00-2:30

VIII. Subcommittee Session I, 2:45-4:00
- A. State's Royalty Share – Bill Corbus, chair
- B. Access to the gas/In-state gas consumption– Ken Thompson, chair
- C. Linking other future opportunities/markets – Carl Marrs, chair

IX. Subcommittee Session II, 4:15-5:30
- A. Alaska Hire/Buy/Build – Mike Navarre, chair
- B. Federal/International Action – Charlie Cole, chair
- C. Environmental Considerations – Peg Tileston, chair

Memo To: Environment Committee Gasline Policy Council Esther Wunnicke, Grace Schaible, Lee Gorsuch, Brian Davies, Bill Britt, Michele Brown and Frank Rue
CC: Jim Sampson, Frank Brown, Ken Freeman
Date: April 4, 2001
RE: Thoughts in preparation for the committee meeting tomorrow, April 5 from 4:30 -5:30 pm

Thank you for agreeing to serve on the Environment Committee. The ideas presented in this memo are preliminary and their purpose is to stimulate your thinking on what we should do and how we should go about doing it. I hope they will "kick start" our discussion tomorrow so that we can at least develop an outline for our work.

Scope of work

Identify and evaluate all possible environmental aspects of natural gas commercialization, including upstream (before gas enters pipeline); pipeline; and downstream (after gas leaves pipeline) activities; prior to, during and after construction. Also identify and evaluated environmental advantages and disadvantages of the use of natural gas within Alaska.

Produce by October 1 a committee report for inclusion in the Council's report. Please be thinking about the form the committee's report should take.

Process

Collect and disseminate information among committee members. Individually, as a committee, or as subcommittees, meet with individuals and organizations that have information and concerns about environmental aspects of various natural gas proposals.

I hope we can function by consensus – working through any difference of opinions to present a final report that is unified. If that is not possible, then a majority/minority position would be appropriate.

It has been suggested that a co-chairman of the Council and a member of each committee attend the public hearings that are scheduled. Please be thinking about which hearing(s) that you might be able to attend.

Questions

What have we learned for permitting, construction and operation of other pipeline projects?
What type of oversight entity is appropriate? Joint Fish & Wildlife Team (JFWF)? Other?
Does DEC, F&G and DNR have adequate personnel to respond to environmental permit requests and concerns? Can the state compete in the job market?

Areas of environmental considerations (starter list – please add your thoughts)

Hydrology
Ground & surface water use
Flow reductions
Surface drainage pattern changes
Wetlands disruptions, impairment and loss
Stream crossings including affect of "cold pipe" crossings in non-permafrost areas
Water quality
Air quality
Erosion
Vegetation changes
Oil & hazardous substance spills
Gravel sources
Noise
Impact of changing from natural gas to coal in Anchorage bowl
Impact of changing from diesel to natural gas in Fairbanks and other locations in Interior Alaska
Effect on habitat
Fish, wildlife and avia-fauna disturbance/displacement

I look forward to our meeting. I hope Michele and Frank can join via teleconference -- Ken Freeman said teleconferencing will be available. Grace will you be anyplace near a phone? I will check with Ken to find out if you call in through a conference operator of if we call you.

If you have any questions or concerns about any of this please contact me.

Peg Tileston
907-561-0540; 907-563-2747 FAX
pegt@alaska.net

Alaska Highway Natural Gas Policy Council
COMMITTEE STRUCTURE

The Alaska Highway Natural Gas Policy Council's Mission:
To promote an Alaska Highway Natural Gas Pipeline project to the lower 48 that also enables creation of a natural gas business in Alaska.

Alaska Hire/Buy/Build – Mike Navarre, chair
Jerry Hood, Rhonda Boyles, Rosemarie Maher, Jake Adams, Peg Tileston
- Use of the Alaska labor pool by contractors and subcontractors
- Use of Alaska businesses
- Training and readiness of Alaskans for jobs on a gas project
- Socio-economic impacts

State's Royalty Share – Bill Corbus, chair
Dave Rose, Ron Duncan, Grace Schaible, Mike Navarre, Ed Rasmuson, Mike O'Connor, Ken Thompson
- Best uses of the state's royalty share: in-kind vs. in-value
- Ensure fair return to the state
- Costs and benefits of the state taking delivery of royalty share
- State promotion and facilitation of project financing – state ownership
- Review other states policies for best practices

Federal/International Action – Charlie Cole, chair
Esther Wunnicke, Bob Penney, Jon Rubini, Jeff Feldman, George Wuerch
- Federal permitting/access
- Federal agency lead
- Canadian permitting/access
- Other contractual considerations
- Domestic markets – Competing sources/sharing of the market
- Canadian national and territorial relations

Access to the gas/In-state gas consumption– Ken Thompson, chair
Rosemarie Maher, Rhonda Boyles, Al Adams, Brian Davies, Jim Jansen, Jerry Hood, Bob Penney
- Demand for in-state natural gas
- Promotion or attraction of investment for in-state distribution and value-added processing
- Best practices valuation/net-back pricing methodology
- Ensuring access to natural gas for local communities
- Benefits of natural gas development to rural Alaska

Linking other future opportunities/markets: GTL, LNG, NGL – Carl Marrs, chair
Jack Roderick, Lee Gorsuch, Jeff Feldman, George Ahmaogak, Ken Thompson
- Options for projects utilizing gas-to-liquids and liquid natural gas
- Best use of natural gas liquids
- Asian/West Coast markets
- Allowing for expanded uses

Environmental Considerations– Peg Tileston, chair
Brian Davies, Esther Wunnicke, Lee Gorsuch, Grace Schaible
- Environmental impacts and necessary protection measures
- Doing it right

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Vegetation changes
Oil & hazardous substance spills
Gravel sources
Noise
Impact of changing from natural gas to coal in Anchorage bowl
Impact of changing from diesel to natural gas in Fairbanks and other locations in Interior Alaska
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If you have any questions or concerns about any of this please contact me.

Peg Tileston
907-561-0540; 907-563-2747 FAX
pegt@alaska.net

Administrative Order No. 188

I, Tony Knowles, Governor of the State of Alaska, under the authority of art. III, secs. 1 and 24 of the Alaska Constitution, establish the Governor's Alaska Highway Natural Gas Policy Council (council).

Purpose

1. Alaska North Slope gas development and transportation to market is of vital public interest. It is in the best interest of the people of Alaska that a North Slope natural gas commercialization project advance, to the maximum extent allowed by law, Alaska hire and use of Alaska businesses; Alaskan access to gas; and a fair share of revenues for Alaskans. This project should improve the standard of living for Alaskans by providing feedstock for new industries, community access to gas, and gas for future commercialization projects that may become feasible as market conditions improve. It is essential that Alaskans have a voice in determining how the state will achieve these goals.

2. As Governor, I join the many Alaskans in believing that the only viable and environmentally responsible project is a natural gas pipeline from Prudhoe Bay to Fairbanks, and then along the Alaska Highway through the Yukon Territory and Alberta to connect with distribution systems in America. This route was approved by Congress in 1977 and is the subject of an international treaty with Canada.

3. The purpose of the council is to engage Alaskans representing a broad spectrum of Alaska interests, experience, and geography to advise the Governor and the Alaska Highway Gas Pipeline Cabinet in determining how the state can best promote the Alaska Highway North Slope natural gas pipeline project and maximize benefits for Alaskans.

Duties

1. The council shall hold statewide meetings to obtain the public's views on how the state can best promote a gas commercialization project and maximize benefits for Alaskans. During the meetings, the council shall present a summary of project options and general topics for discussion.

2. Before the statewide meetings, the council shall meet to plan its work schedule and prepare the presentation for the meetings.

3. No later than November 30, 2001, the council shall present a summary of public comments, consensus recommendations, and other information gathered to the Governor, the Alaska Highway Gas Pipeline Cabinet, and the public.

4. The council shall deliberate and make recommendations on topics related to natural gas commercialization, including

a. the benefits of natural gas development to Alaska communities, including those located in rural areas of Alaska;

b. the best uses of the state's royalty share of the gas and promotion or attraction of investment for in-state and value-added processing;

c. the costs and benefits of the state taking delivery of its royalty share of the gas in Alaska versus allowing a project developer to include the gas in its delivery flow to the Lower 48 states;

d. options for projects utilizing gas-to-liquids, liquified natural gas, and natural gas liquids;

e. demand for in-state natural gas consumption and its effects on a gas project;

f. environmental impacts and necessary protection measures;

g. training and readiness of Alaskans for jobs on a gas project, use of the Alaska labor pool by contractors and subcontractors, and use of Alaska businesses; and

h. state promotion and facilitation of project financing, including potential ownership by the state of some or all of a project.

Membership and General Provisions

The council shall be comprised of Alaskans representing a diversity of interests, experience, and geography and appointed by the Governor to serve at the pleasure of the Governor. Members of the Alaska Highway Gas Pipeline Cabinet shall serve as non-voting, ex-officio members of the council.

The Office of the Governor and other state agencies shall provide professional and administrative staff assistance to support the activities of the council. The Department of Law shall provide legal assistance to the council.

To reduce costs, the council shall use teleconferencing or other electronic means to the extent practicable in order to gain the widest public participation at minimum cost.

The council shall establish procedures for voting and meetings. Council members who are not state employees serve without compensation and are entitled to per diem and travel expenses in the same manner permitted for members of other state boards and commissions. Per diem and travel expenses for members of the council who are appointed as a member of a state agency are the responsibility of that state agency. The Governor shall designate two members of the council as co-chairs. Meetings of the council shall be conducted and notices of such meetings provided in accordance with AS 44.62.310 (Open Meetings Law).

Amendments and Revocations

This Order amends Administrative Order No. 187 to change the name of the Gas Pipelines Cabinet to the Alaska Highway Gas Pipeline Cabinet.

This Order revokes Administrative Order 152.

This Order takes effect immediately.

Dated at Anchorage, Alaska, this 24th day of January, 2001.

State of Alaska

Office of the Governor

Tony Knowles
Governor
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Juneau, Alaska 99811-0001

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FOR IMMEDIATE RELEASE: January 8, 2001 01-006

ALASKA HIGHWAY GASLINE TOPS KNOWLES' SESSION AGENDA

Legislation, Administrative Order, Budget Request to Jump Start Gasline Project

Continuing his commitment to push development of an Alaska natural gas pipeline, Gov. Tony Knowles welcomed the opening of the 22nd Legislature today with legislation to facilitate development of a natural gas pipeline and an Administrative Order establishing a streamlined, one-stop state structure for gasline permitting and oversight. Saying "my way IS the highway," Knowles is also seeking $4 million to jump start construction of a pipeline that follows the Alaska Highway by beginning work on needed permits and rights-of-way.

"Alaska's natural gas can be the foundation of a 21st century economy of high tech resource development, high tech manufacturing, and new business growth and quality of life based on affordable clean energy," Knowles said. "With known and estimated reserves of up to 100 trillion cubic feet, natural gas can fuel our economy for the next 50 to 70 years, but to start this mammoth undertaking, we need a single point of contact.

"The Administrative Order that I signed today creates a natural gas policy cabinet and a State Pipeline Coordinator to coordinate state permits, authorizations, and oversee construction of a pipeline to transport natural gas from the Alaska North Slope to market," Knowles said. "Our objective is to implement the 'one-stop shopping' approach to maximize efficiency in processing required approvals and permits and optimize state pipeline expertise and performance."

In addition to creating the pipeline coordinators office, Knowles' order establishes a natural gas policy cabinet, which includes the commissioners of each state agency involved the development of a gasline project. This includes the Departments of Natural Resources, Environmental Conservation, Fish and Game, Revenue, Transportation and Public Facilities, Labor and Workforce Development, and Community and Economic Development, as well as the director of the Division of Governmental Coordination, the director of the Governor's office in Washington D.C., and the Attorney General.

Under the order, each agency involved in pipeline permitting and authorization will appoint a liaison officer to be the pipeline coordinator's office to represent the agency in matters relating to permitting, authorization, and oversight of the project.

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Liaison officers will process gasline permits and authorizations as required by their agency; assist as necessary with authorizations by other agencies; manage and perform work necessary to oversee construction of a gasline; and provide other necessary assistance to the coordinator's office in their areas of expertise.

"The order establishes a fully integrated state organization that utilizes existing government structure and processes to the maximum extent possible, minimizes impacts to existing agency functions, and promotes internal alignment of state agencies," Knowles added. The order is for administrative purposes only and does not modify the statutory and regulatory authorities of designated agencies. The Pipeline Coordinator will submit periodic progress reports to the governor and the Gas Pipeline Cabinet that summarize goals and objectives and accomplishments against those goals and objectives.

Knowles also introduced legislation today that amends the "Stranded Gas" legislation that was passed in 1998 to facilitate natural gas commercialization to include an Alaska Highway natural gas pipeline or a gas-to-liquids (GTL) project. The earlier bill allowed the state to negotiate the fiscal terms of a gasline including a contract for payments in lieu of taxes, but specifically applied to a liquefied natural gas project. The most promising market for Alaska gas today is through a pipeline to the midwestern states. Other companies, meanwhile, are exploring new GTL technology. Knowles' bill would expand the provisions in the stranded gas bill to any viable project.

Knowles' announcements today are his latest steps to facilitate development of a pipeline to carry Alaska's 36 trillion cubic feet of known gas reserves to market. Since taking office in 1994, Knowles has brought in experts to review the state's position in the world gas market and analyze steps the state could take to improve the economics of gas development. Knowles touted Alaska gas during trade missions to Japan, Korea, and China, and as the nation's gas supply dwindled and prices rose sharply, he helped organize a summit in Ohio to explore domestic markets for Alaska gas.

Dedicating the remainder of his term to starting work on a gas project, Knowles established the state's principles for development, saying it must provide jobs for Alaskans, use Alaska businesses, and allow in-state access to the gas. In November, Knowles announced his preference of a pipeline route that follows the Alaska Highway, saying use of this established transportation corridor would be the fastest and cheapest way to bring Alaska gas to market. Just last week, Knowles announced the hiring of former Resource Development Council director Ken Freeman as his new business liaison, with special duties related to the gasline project.

"Once again, Alaska finds itself well positioned to meet America's growing thirst for energy," Knowles said. "Our challenge is to advance the interests of Alaskans as we work with industry and the marketplace. This legislation and creation of the State Pipeline Coordinator's Office to lead gasline development are important and necessary steps to facilitate this development for Alaska's future."

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Broadcasters note: Radio actualities will be available shortly after the news conference at 800-478-5669, or 465-5213 in Juneau.

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FOR IMMEDIATE RELEASE: January 26, 2001 01-027

KNOWLES ANNOUNCES CO-CHAIRS OF NEW ALASKA HIGHWAY NATURAL GAS POLICY COUNCIL

Prominent Alaskans to Help State Direction on Gas Development; International Energy Firm to Advise State and Alaskans

ANCHORAGE--Continuing his push to develop an Alaska Highway natural gas pipeline, Gov. Tony Knowles today announced two initiatives to further commercialization of Alaska's North Slope gas. By state Administrative Order, the governor created the Governor's Alaska Highway Natural Gas Policy Council to be chaired by two prominent Alaskans – retired ARCO Alaska Senior Vice President Frank Brown of Anchorage and former Fairbanks North Star Borough Mayor Jim Sampson of Fairbanks.

Knowles also announced that his administration has contracted with one of the world's top international oil and gas experts, Cambridge Energy Research Associates, to provide Alaskans expertise and analyses of various aspects of gas development.

"When it comes to natural gas, after two decades of false starts and broken dreams, the economic and political stars are finally aligned in Alaska's favor," Knowles said. "Despite our distance from domestic markets, our natural gas is more economic now than ever. The Governor's Alaska Highway Natural Gas Policy Council will engage the public as it analyzes the many issues related to gas development and makes recommendations to Alaskans."

The governor asked the council to begin its work soon and report back with recommendations by November 30, so their work can be incorporated into gas line legislation and project development. Knowles noted that his new special assistant for economic development, Ken Freeman, will provide staff assistance to the council.

Cambridge Energy also will assist the council and Alaskans in analyzing the many aspects of gas development. "Led by Pulitzer Prize-winner author Daniel Yergin, who won the honor for his thorough history of world oil development, Cambridge Energy can provide the objective market analysis we need to make the important public policy decisions facing Alaska," Knowles said.

The governor also used his remarks to the Alliance to praise developments in the oil patch.

Citing a recent analysis of the impact of the oil industry on Alaska's economy, Knowles noted that more than one in ten private sector jobs in the state are the result of this industry, which also has the highest average wage and the largest private sector payroll in Alaska. The investment the oil and gas industry makes in Alaska each year is roughly equal to the state's annual general fund spending.

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"Alaska's major producers, especially BP and Phillips, are working hard to keep those good news numbers coming by aggressively exploring for oil and gas on the North Slope," he said. "By investing about 25 percent more in capital spending, Phillips has targeted a 14 percent oil production increase over the next 5 years; BP 17 percent.

"Other companies such as Alberta Energy, Unocal, Marathon and others, are equally bullish on the Slope and in Cook Inlet. Last fall's North Slope area-wide sale set a record for state oil and gas lands leased for exploration, more than 713,000 acres," Knowles said. "In Cook Inlet, there's a renewed interest in exploration of natural gas and Forest Oil set the first new platform in Cook Inlet since 1986. The state is responding to all this interest with 16 area-wide lease sales in the next 5 years."

After Alaska's success in convincing the national administration to open the National Petroleum Reserve-Alaska to oil and gas exploration, Knowles said the challenge now is to persuade America and Congress to permit environmentally responsible development in the Arctic National Wildlife Refuge.

"We breathed a sigh of relief when the Clinton administration listened to Alaskans and declined to make ANWR a national monument," he said. "With a new national administration, we're better positioned for success in ANWR. But we shouldn't kid ourselves into believing we face a cakewalk.

"Our challenge is to demonstrate, using the latest technology and relying on the world's safest oil transportation system, that we can develop the oil beneath the refuge, while protecting the environment and fish and wildlife that we value so much and which are such an important symbol for so many Americans," the governor said.

Knowles has taken a number of steps to advance gas development, including visiting personally with the top officials of Alaska's oil and gas producing companies. He co-sponsored a natural gas summit in Columbus, Ohio attended by experts from more than 40 states.

Two weeks ago, he signed Administrative Order 187 creating a special Natural Gas Pipeline Cabinet and directing state agencies to work aggressively for timely one-stop permitting and right-of-way preparation. The Knowles administration has introduced legislation extending the state's ability to negotiate tax flexibility for natural gas projects, like an Alaska Highway gas line.

These initiatives are supported by a multi-million dollar budget request, which Knowles has asked the Legislature to act on quickly.

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FOR IMMEDIATE RELEASE: February 2, 2001 01-035

KNOWLES ADVANCES ALASKA HIGHWAY GASLINE WITH POLICY COUNCIL

Civic, Business Leaders Included in 28-Member Panel

Citing their breadth of experience and leadership in keeping Alaska's economy healthy, Gov. Tony Knowles today announced 26 members of the Governor's Alaska Highway Natural Gas Policy Council. The council will spend the next 10 months focusing on the best ways to advance construction of a natural gas pipeline down the Alaska Highway.

"This council is one of the smartest, most experienced, and highly dedicated group of Alaskans ever assembled for a single purpose: to help guide Alaska public policy as we build a natural gas pipeline," Knowles said. "I'm honored each of these Alaskans answered my call to public service for this important effort. I know Alaskans will be reassured that their views about this enormous project will be considered."

Knowles created the council January 26, when he signed an administrative order to "engage Alaskans representing a broad spectrum of Alaska interests, experience, and geography to advise the Governor and the Alaska Highway Gas Pipeline Cabinet in determining how the state can best promote the Alaska Highway North Slope natural gas pipeline project and maximize benefits for Alaskans."

The Governor last Friday announced the council's two co-chairmen: retired ARCO Alaska Senior Vice President Frank Brown of Anchorage and Jim Sampson, Executive Director of the AFL-CIO in Alaska and a former mayor of the Fairbanks North Star Borough. The 26 other members of the council appointed by the Governor today include:

- Former state representative and Kenai Peninsula Borough Mayor Mike Navarre;
- Anchorage Mayor George Wuerch;
- Former state Attorney General Grace Schaible of Fairbanks;
- Bill Corbus, president of Alaska Electric Light and Power Company of Juneau;
- Former state Attorney General Charlie Cole of Fairbanks;
- Former state Senator Al Adams of Kotzebue;
- Carl Marrs, president and CEO of Cook Inlet Region, Inc., of Anchorage;
- Rosemarie Maher, president and CEO of Doyon, Ltd., of Fairbanks;
- Former state Natural Resources Commissioner Esther Wunnicke of Anchorage and a member of the public policy group Alaska Common Ground;
- Former Anchorage Mayor Jack Roderick, a noted Alaska author and oil industry historian;
- Oil and gas consultant Brian Davies of Anchorage and former vice president for BP in Alaska;
- Jim Jansen, President of Lynden transportation company in Anchorage;

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- Former Permanent Fund Executive Director Dave Rose, currently president of Alaska Permanent Capital Management;
- Ed Rasmuson, chairman of the National Bank of Alaska;
- Lee Gorsuch, chancellor of the University of Alaska Anchorage;
- Anchorage businessman Bob Penney, a member of the North Pacific Fisheries Management Council;
- Fairbanks North Star Borough Mayor Rhonda Boyles;
- Ron Duncan, president of GCI;
- Former ARCO Alaska President Ken Thompson, currently CEO of Pacific Rim Leadership Development of Anchorage;
- Peg Tileston of Anchorage, an environmental citizen activist and board chair of Alaska Common Ground, a non-partisan public policy group;
- Jake Adams, president of the Arctic Slope Regional Corporation
- North Slope Borough Mayor George Ahmaogak,
- Anchorage attorney Jeff Feldman;
- Jon Rubini, an Anchorage real estate businessman with statewide investments;
- Jerry Hood, chief executive officer of Alaska Teamsters Union local 959; and
- Mike O'Connor, president of Peak Oil Field Services Company.

"Commercialization of North Slope natural gas via the gasline project is the biggest economic opportunity to come to Alaska in years," Knowles said. "Taking full advantage of this opportunity won't be easy, though, and that's why we need a broad based, diverse group of Alaskans to work through the many issues that have to be addressed. I'm confident that this group will ensue public participation and produce recommendations that will protect the public's interests and make Alaskans proud as the gasline moves forward."

The Governor asked the council to hold statewide meetings to obtain the views of Alaskans on how the state can best promote a gas commercialization project and maximize benefits for Alaskans. He asked it to report back with recommendations by November 30, so their work can be incorporated into gas line legislation and project development. Among the issues the council will consider are:

- Benefits of natural gas development to Alaska communities, including those located in rural areas of Alaska;
- Best uses of the state's royalty share of the gas and promotion or attraction of investment for in-state and value-added processing;
- Costs and benefits of the state taking delivery of its royalty share of the gas in Alaska versus allowing a project developer to include the gas in its delivery flow to the Lower 48 states;
- Options for projects utilizing gas-to-liquids, liquified natural gas, and natural gas liquids;
- Demand for in-state natural gas consumption and its effects on a gas project;
- Environmental impacts and necessary protection measures;
- Training and readiness of Alaskans for jobs on a gas project, use of the Alaska labor pool by contractors and subcontractors, and use of Alaska businesses; and
- State promotion and facilitation of project financing, including potential ownership by the state of some or all of a project.

Two weeks ago, Knowles signed an administrative order that created a special Alaska Highway Natural Gas Pipeline Cabinet and directing state agencies to work aggressively for timely one-stop permitting and right-of-way preparation. Members of the Gas Pipeline Cabinet will serve as ex officio members of the council.

Knowles also recently introduced legislation that amends the "stranded gas" legislation that was passed in 1998 to facilitate natural gas commercialization to include an Alaska Highway natural gas pipeline or a gas-to-liquids (GTL) project.

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FOR IMMEDIATE RELEASE: February 27, 2001 01-063

NATION'S GOVERNORS BACK ALASKA HIGHWAY GASLINE

Knowles Sponsored Resolution Adopted by National Governors' Association

Noting that America is dependent on reliable, reasonably priced energy supplies to support its economy and the demand for natural gas is growing faster than any other energy source, the National Governors' Association (NGA) today unanimously passed a resolution in support of responsible development of Alaska natural gas. The resolution also supports development of an Alaska Highway Natural Gas pipeline to carry that gas to domestic markets.

"This is the first national forum that is bi-partisan and represents all 50 states, that is solidly behind not just the transportation of Alaska natural gas but selecting the route that's in the national interest," said Gov. Tony Knowles, who sponsored the resolution. "This is an important step forward and will answer questions about the broad base of support that we have, particularly in that it designated the Alaska Highway as the preferred route."

The resolution concludes: "The governors endorse, pending completion of appropriate environmental review, a project to bring Alaska gas to market via a pipeline from the North Slope along the Alcan Highway through Canada to the North American distribution system. Any such project must ensure full pipeline safety to protect the public and environment."

The governors also urged the federal government to endorse policies that increase the availability of North American natural gas at reasonable prices to residential, commercial, industrial, and electric generation consumers. The resolution calls on federal and state governments to work together to allow for appropriate access to their public-owned lands for natural gas exploration, production or transmission, while protecting environmentally sensitive areas.

The resolution notes that the largest single untapped supply of natural gas available to North American is located in Alaska, where there are proven reserves of 35 trillion cubic feet of gas and estimated reserves of more than 100 trillion cubic feet. In support of the Alaska Highway route, the resolution notes the agreement in the 1970's between the United States and Canada to use the Alaska Highway route to transport Alaska natural

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gas to the existing North American distribution system. Key rights-of-way and regulatory approvals for the project are still valid.

The resolution states that an Alaska Highway pipeline would parallel an existing highway corridor and not cross any national conservation system units. Such a project would be the biggest private construction project in North American history with the potential to meet a significant portion of the projected energy needs of United States for years to come.

"Alaskans understand that if we are to meet the American market demand, where the need is the greatest and it is economically in our advantage, then the Alaska Highway is the right route," Knowles said. "Construction of the Alaska Highway natural gas pipeline also opens other opportunities for the use of our gas, whether Gas-to-Liquids or Liquefied Natural Gas. This pipeline does not oppose other alternatives, but in fact helps them."

The NGA resolution is the latest effort made by Knowles to spur development of Alaska's Natural Gas. Since taking office he has tapped national and international experts to review ways to commercialize this undeveloped resource and touted Alaska natural gas on trade missions to Asia and the lower 48 states. The NGA resolution follows a similar resolution passed last December by the Western Governors' Association.

Knowles recently formed the Gas Advisory Council, comprised of 28 prominent Alaskans, to examine how the state can best maximize the benefits of an Alaska Highway Gas Pipeline project. The first meeting of the council will take place this Thursday, March 1, from 10:30 to 2 at the Anchorage Sheraton. Knowles and Lt. Gov. Fran Ulmer will attend the meeting, which is open to the public. In the coming months, the council will seek public comment on such things as Alaska hire, ensuring access to the gas for Alaskans, and determining the best use of the state's royalty share.

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Broadcasters: radio actualities of Gov. Knowles discussing the NGA resolution are available on the Governor's Information Line at 800-478-5669, or 465-5213 in Juneau.

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FOR IMMEDIATE RELEASE: February 28, 2001 01-066

ALASKA HIGHWAY NATURAL GAS COUNCIL TO MEET THURSDAY

Knowles, Ulmer to Address Council's First Meeting at Anchorage Sheraton

The Alaska Highway Natural Gas Policy Council will conduct its first meeting Thursday, March 1 from 10:30 a.m. to 2:00 p.m. at the Anchorage Sheraton Hotel. Gov. Tony Knowles will address the opening session of the council and convey his vision for commercializing Alaska's North Slope gas and maximizing the benefits of a gas pipeline for Alaskans.

Knowles formed the council by administrative order last month to examine how the state can maximize the benefits of an Alaska Highway gas pipeline project. Comprised of 28 prominent Alaskans, the council will also seek public comment on such things as Alaska hire, ensuring access to the gas for Alaskans, and determining the best use of the state's royalty share. A written report will be submitted to the Governor and members of his gas cabinet by November 30.

The first meeting of the council will serve as an organizational session and plan for upcoming public hearings. The agenda will begin with remarks from Knowles, Lt. Gov. Fran Ulmer, and Department of Natural Resources Commissioner Pat Pourchot. Representatives of Cambridge Energy Research Associates will also be in attendance to discuss gas supply and demand in domestic and international markets.

The council is led by retired ARCO Alaska Senior Vice President Frank Brown of Anchorage, and former Fairbanks North Star Borough Mayor Jim Sampson. Members of Knowles' special Alaska Highway Natural Gas Pipeline Cabinet serve as ex-officio members of the Policy Council and will attend Thursday's meeting.

The meeting is open to the public and the press. Members of the public can also listen to the meeting via teleconference at Legislative Information Offices statewide.

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FOR IMMEDIATE RELEASE: March 1, 2001 01-068

KNOWLES OPENS MEETING OF ALASKA HIGHWAY GAS COUNCIL

Charges Panel with Tackling Important Public Policy Questions

Saying the social and economic benefits of the development of Alaska's vast natural gas resources are enormous, Gov. Tony Knowles today welcomed members of his Alaska Highway Natural Gas Policy Council at their first meeting. Knowles charged the 28-member panel of community, business, and labor leaders with tackling the important public policy questions that need to be answered before development can begin.

"I created this council for one important reason: to ensure that the interests of Alaskans are protected as we develop our North Slope natural gas," Knowles said. "This means making sure that Alaskans are hired to build and operate the gas pipeline and that Alaska businesses and products are used. It means making sure that Alaska communities have access to gas. And it means ensuring that Alaskans receive a fair share of the revenues generated on this resource which belongs to all of us."

Knowles appointed 28 Alaskans to the Council representing a wide range of interests. He named former ARCO Alaska Executive Frank Brown of Anchorage and former Fairbanks Mayor Jim Sampson to be co-chairs. Members of the governor's Natural Gas Cabinet will serve as ex officio members of the council, along with Lt. Gov. Fran Ulmer.

"Many of us in this room were involved in development of the Alaska oil pipeline and rarely does a generation get the opportunity to be involved in two projects of that magnitude," Knowles said. "What a privilege and opportunity it is for all of us to be involved with it."

In his Administrative Order creating the council, Knowles outlines several broad topics for consideration, ranging from direct state participation in a gas development project to environmental impacts. Six specific committees of the council will look at: Alaska hire and the use of Alaska businesses; best uses for the state's royalty share; in-state access to the gas; needed federal and international action; future markets opportunities such as linked LNG and GTL facilities; and environmental considerations.

Knowles noted that many more issues will likely be raised between today and the November 30 deadline he set for the council's report.

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"I ask you to visit Alaska communities, listen to Alaskans, engage the assistance of experts and ask tough questions of me, my administration, and sponsors of the various proposals for using our gas," Knowles said. "Our state has a lot of experts when it comes to natural gas development. Probably about 630,000 of them – and that's the way it should be. A natural gas project of this magnitude becomes available only very rarely – so it's incumbent on us to make sure it's done right."

An estimated 100 trillion cubic feet or more of natural gas is believed to be held beneath Alaska's North Slope. Knowles named his policy group the "Alaska Highway Natural Gas Policy Council," believing, as most Alaskans do, that the best way to develop our gas is via a pipeline along the Alaska Highway to domestic energy markets in the Lower 48.

"This is based on three facts: first, the consensus of the energy world is that the only market today for financing a pipeline and the best economic return to Alaska is in the United States," Knowles said. "Second, Alaska must act with a high sense of urgency in supplying this market. The energy gap created by this opportunity will be filled, and should be filled by Alaska gas. Third, a project of this size and scope must have national and Canadian support.

"There's a single hard, cold reality when it comes to our gas development: it won't happen unless it's commercially viable," Knowles added. "As many of you know, we've been dreaming and scheming about Alaska gas development for a generation. Yet it hasn't happened because it hasn't met the key market test. An Alaska Highway gasline does not exclude other projects. In fact, the consensus of experts is that it makes other types of gas projects, including a future LNG line, more economic."

Knowles said the Alaska Highway route also brings gas far closer to markets in Southcentral should Cook Inlet reserves ever prove inadequate to meet demand. The highway route even compliments development of Canadian gas in the Mackenzie Valley.

"Our mission is to promote the Alaska Highway Natural Gas Pipeline project to North America that enables creation of a natural gas industry in Alaska," Knowles concluded. "My charge to you is to help synthesize the views and suggestions of Alaskans and help resolve the many policy issues tied to gas development."

Noting the need to begin work now on reviewing and permitting this project, Knowles also asked for the council's support in making sure the Legislature provides adequate resources for the job.

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SCOMM

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Alaska Highway
Natural Gas Policy Council

Senate President Rick Halford

Alaska Highway Natural Gas Policy Council
TIMELINE

(All dates/locations subject to change)

March 1 – **Full council meeting** kick-off in Anchorage

March 23 – **Full council meeting**/workshop in Anchorage

April 5 – **Full council meeting**/workshop in Anchorage
immediately followed by subcommittee meetings

April 18 – Public hearing in Fairbanks

May 17 – Public hearing in Kenai

May 24 – **Full council meeting**/public hearing in Anchorage

June 14 – Public hearing in Tok/Delta

July 19 – **Full council meeting**/public hearing in Barrow
(members not in Barrow can participate via videoconference from Anchorage)

August 2 – Public hearing in Southeast

August 23 – Public hearing in Valdez

September 17 – **Full council meeting** in Anchorage

November 8 – **Final full council meeting** in Anchorage

Other important dates:

October 1 – Written reports due from subcommittees

October 30 – First draft of final report complete

November 30 – Final report presented to Governor Knowles

Revised 4/16/01

Alaska Highway Natural Gas Policy Council
COMMITTEE STRUCTURE

Council Mission: To promote an Alaska Highway Natural Gas Pipeline project to the lower 48 that also enables creation of a natural gas business in Alaska.

Alaska Hire/Buy/Build – Mike Navarre, chair
Jerry Hood, Rhonda Boyles, Rosemarie Maher, Jake Adams, Peg Tileston
- Use of the Alaska labor pool by contractors and subcontractors
- Use of Alaska businesses
- Training and readiness of Alaskans for jobs on a gas project
- Socio-economic impacts

State's Royalty Share – Bill Corbus, chair
Dave Rose, Ron Duncan, Grace Schaible, Mike Navarre, Ed Rasmuson, Mike O'Connor, Ken Thompson
- Best uses of the state's royalty share: in-kind vs. in-value
- Ensure fair return to the state
- Costs and benefits of the state taking delivery of royalty share
- State promotion and facilitation of project financing – state ownership
- Review other states' policies for best practices
- Evaluation of state tax structure

Federal/International Action – Charlie Cole, chair
Esther Wunnicke, Bob Penney, Jon Rubini, Jeff Feldman, George Wuerch
- Federal permitting/access
- Federal agency lead
- Canadian permitting/access
- Other contractual considerations
- Domestic markets – Competing sources/sharing of the market
- Canadian national and territorial relations

Access to the gas/In-state gas consumption– Ken Thompson, chair
Rosemarie Maher, Rhonda Boyles, Al Adams, Brian Davies, Jim Jansen, Jerry Hood, Bob Penney
- Demand for in-state natural gas
- Promotion or attraction of investment for in-state distribution and value-added processing
- Best practices valuation/net-back pricing methodology
- Ensuring access to natural gas for local communities
- Benefits of natural gas development to rural Alaska

Linking other future opportunities/markets: GTL, LNG, NGL – Carl Marrs, chair
Jack Roderick, Lee Gorsuch, Jeff Feldman, George Ahmaogak, Ken Thompson
- Options for projects utilizing gas-to-liquids and liquid natural gas
- Best use of natural gas liquids
- Asian/West Coast markets
- Allowing for expanded uses

Environmental Considerations– Peg Tileston, chair
Brian Davies, Esther Wunnicke, Lee Gorsuch, Grace Schaible
- Environmental impacts and necessary protection measures
- Doing it right

The Governor's Alaska Highway Natural Gas Policy Council Members

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Mike	O'Connor	Peak Oilfield Services	2525 C Street, Suite 201	Anchorage	99503	263-7000	263-7070	mikeoconnor@peakalaska.com
Bob	Penney	PENCO AK	3620 Penland Parkway	Anchorage	99508-2099	276-2222	278-0896	rcpenny@aol.com
Edward	Rasmuson	National Bank of Alaska	P.O. Box 100600	Anchorage	99503	265-2927	265-2068	pat.hostetter@nbak.com
Jack	Roderick		1620 Hidden Lane	Anchorage	99501	272-8089	272-8089	roderick@alaska.net
Dave	Rose	Alaska Permanent Capital Managem	900 West 5th Avenue, Suite 601	Anchorage	99501	272-7575	272-7574	apcm@alaska.net
Jon	Rubini		1007 W Ave., 3rd Suite 100	Anchorage	99501	222-7112	222-7197	rubij@foster.com
Jim	Sampson		1000 Bennett Road	Fairbanks	99712	456-4584	452-6285	jimsamp@mosquitonet.com
Grace	Schaible		P.O. Box 61560	Fairbanks	99706	452-1136	452-7136	gbschaib@ptialaska.net
Ken	Thompson	Pacific Rim Leadership Developmen	3601 C St. Suite 1400	Anchorage	99503	770-1600	770-1626	ken@pacrimldr.com
Peg	Tileston		4780 Cambridge Way	Anchorage	99503-7012	561-0540	563-2747	pegt@alaska.net
George	Wuerch	Municipality of Anchorage	P.O. Box 196650	Anchorage	99519-6650	343-4431	343-4499	wwmayor@ci.anchorage.ak.us
Esther	Wunnicke		1406 Sunrise Dr.	Anchorage	99508	279-4996	258-1559	wunn@alaska.net
Ken	Freeman	Office of the Governor	550 W 7th Aveune, Suite 1700	Anchorage	99501	269-7450	269-7461	Ken_Freeman@gov.state.ak.us

Alaska Highway Natural Gas Policy Council

AGENDA

Organizational Meeting – Thursday, March 1, 2001
Anchorage Sheraton Hotel – 10:30 a.m. to 2:00 p.m.

I. Welcoming remarks from Council Co-Chairs Jim Sampson/Frank Brown

II. Opening remarks from Governor Tony Knowles

III. Opening remarks from Lt. Governor Fran Ulmer

IV. Presentation from Department of Natural Resources Commissioner Pat Pourchot (see April 18th meeting)

V. Presentation from Cambridge Energy Research Associates

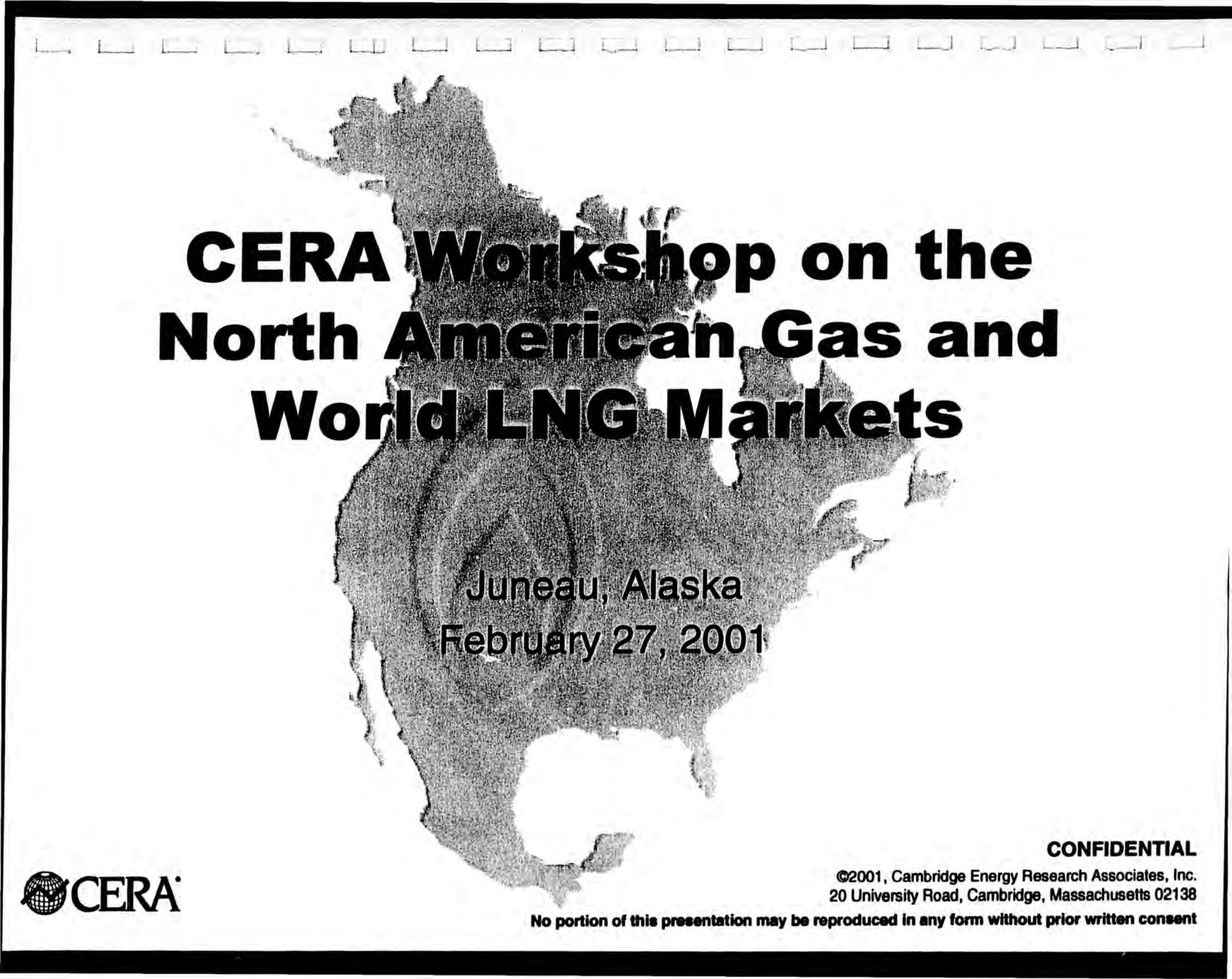
VI. Ten-minute break

VII. Working lunch and council member self-introductions

VIII. Establish organizational structure

IX. Establish timeline and public hearing schedule

X. Closing remarks from Council Co-Chairs Jim Sampson/Frank Brown



CERA Workshop on the North American Gas and World LNG Markets

Juneau, Alaska
February 27, 2001

CERA

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North American Gas Market Overview

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Winter 2000/01: A Market Exposed

Supply Response



- Little help this winter
- Canada: Still struggling to grow
- LNG: limited new gas

Storage



- October 31:record low in the United States
- Early winter: held in reserve?
- March 31: how low can it go?

Weather



- Potential demand rebound of 3–4 Bcf per day
- The 900 Bcf wild card

Power Market Development



- Building marginal winter demand
- Competition for space in the pipes

New Infrastructure



- Alliance; but little gas to follow
- M&N fills, no help to NY
- Rockies projects proliferate

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Source: Cambridge Energy Research Associates.

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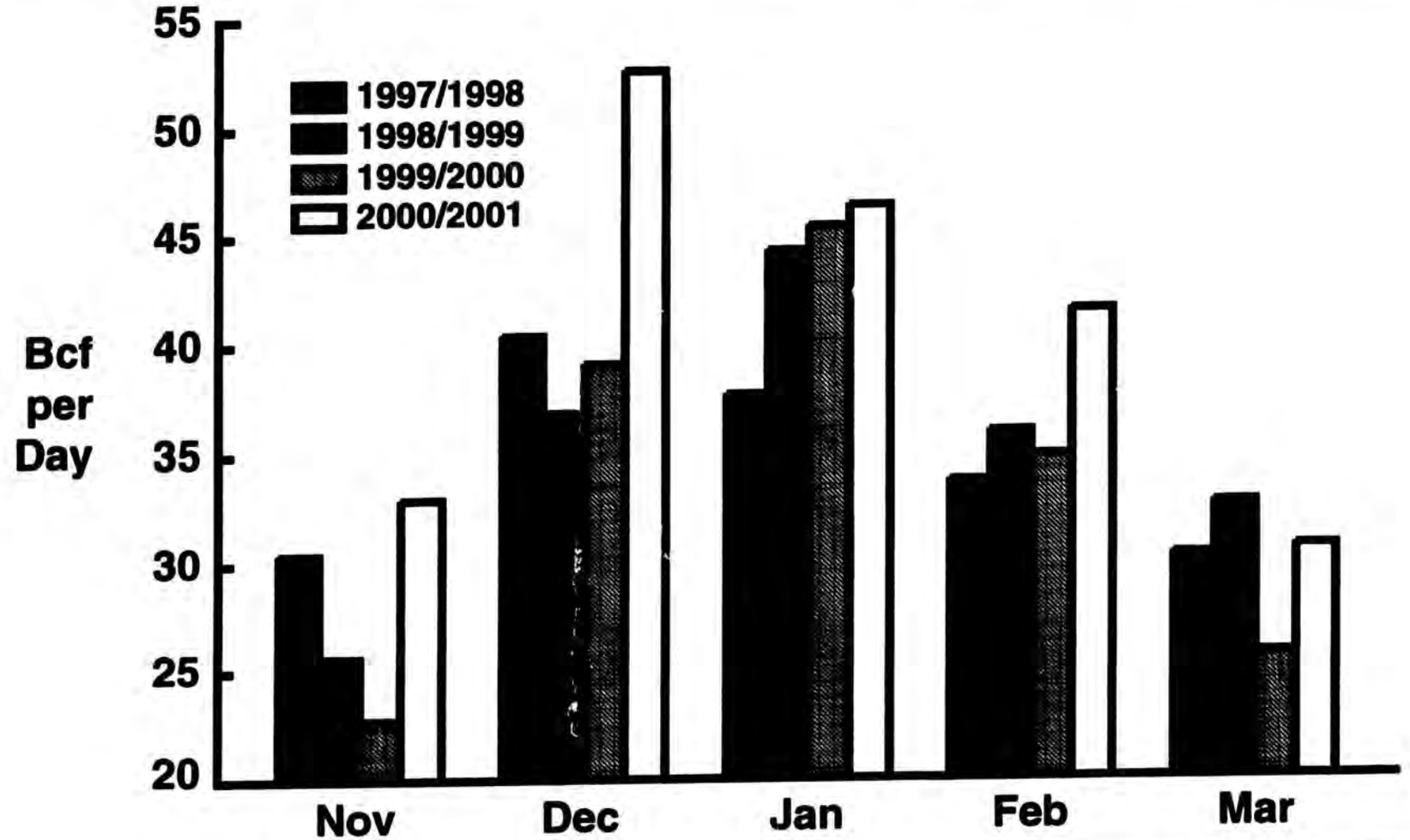
After the Spike - Winter Gas Heating Demand



Source: Cambridge Energy Research Associates
Notes: Includes residential and commercial demand. Winter of 2000/2001 assumes 15-year normal weather

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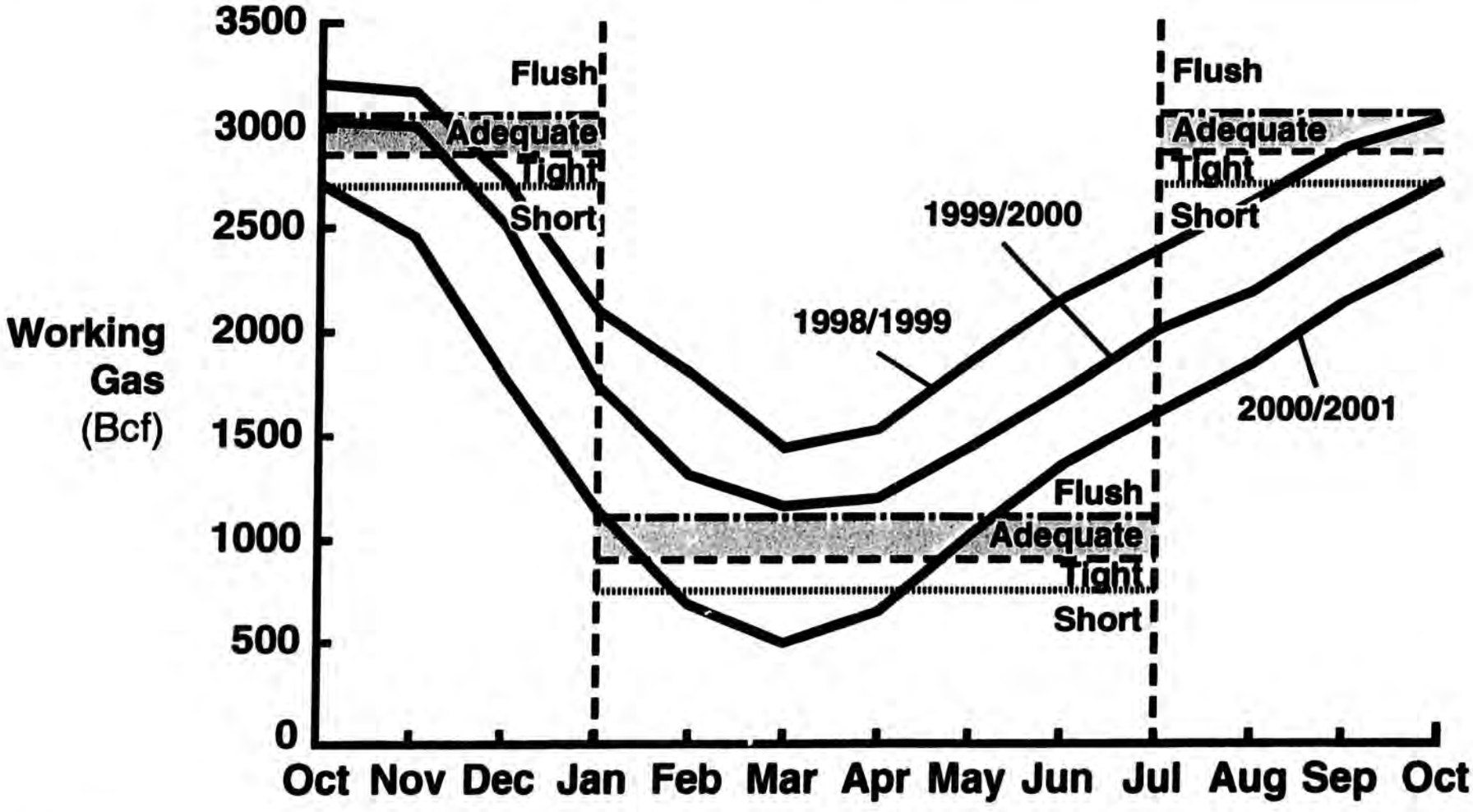
The Storage Cushion Deflates: Supply Declines Drive Down Inventories



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Source: Cambridge Energy Research Associates.

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2001 and Beyond: Supply Recovery, Demand Pressure

Supply Response



- Increased rig activity drives L-48 rebound of 0.8 to 1.0 Bcf per day
- Deep water ramps up
- Canadian supply builds
- LNG: limited new gas until 2003

Storage



- Recovery from historic lows
- Driving price volatility
- Injection pressure—again

Power Generation



- Ongoing development > 10,000 MW per year
- Competition with injections
- Demand pressure >1 Bcf per day
- Link to economic growth

Infrastructure and Regulation



- Projects advance, but little built until 2002
- LNG: same
- New prices reawaken old questions
- A retail shakeout?

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Source: Cambridge Energy Research Associates.

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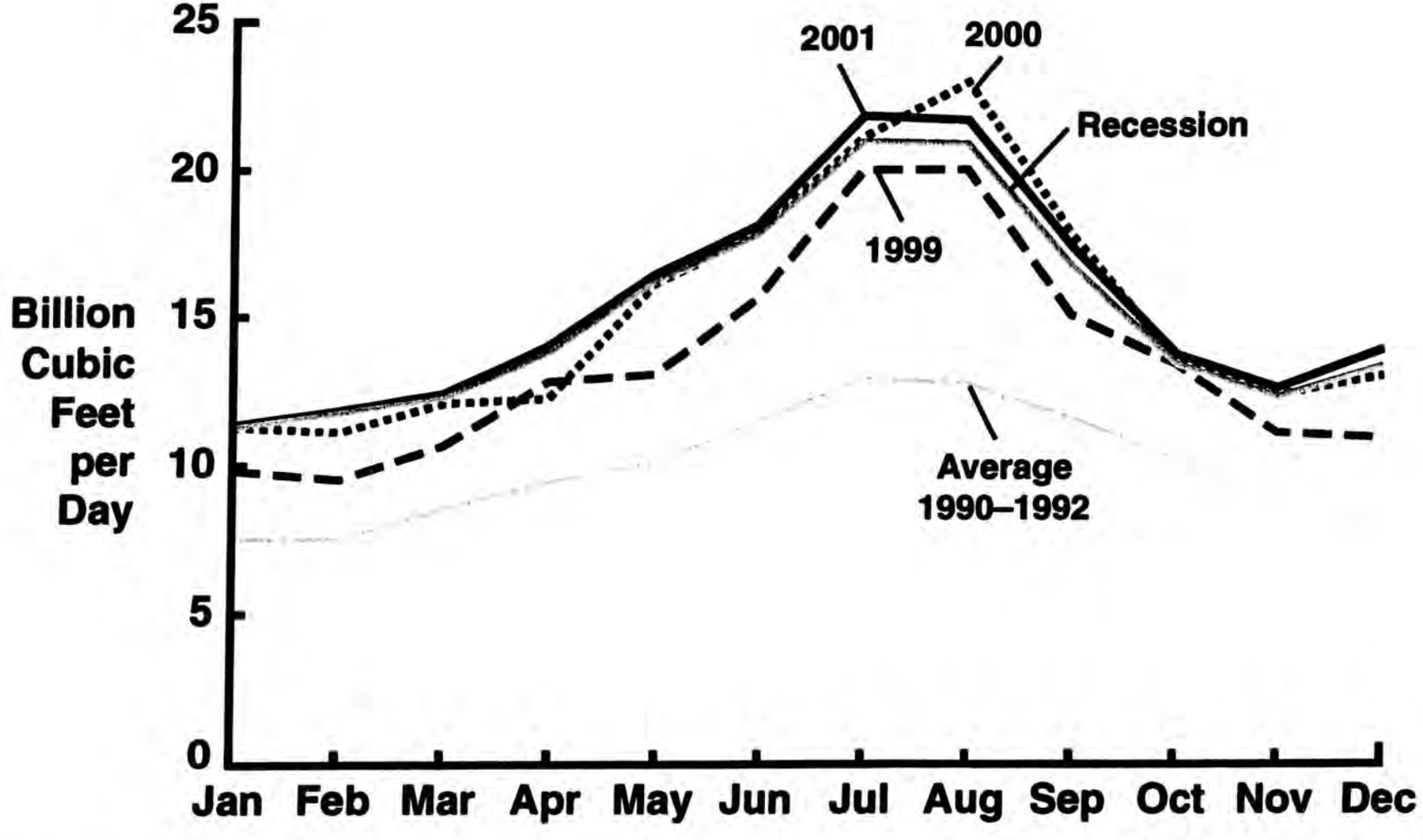
Recession versus Continued Growth: Gas Demand for Power Generation



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Source: Cambridge Energy Research Associates.

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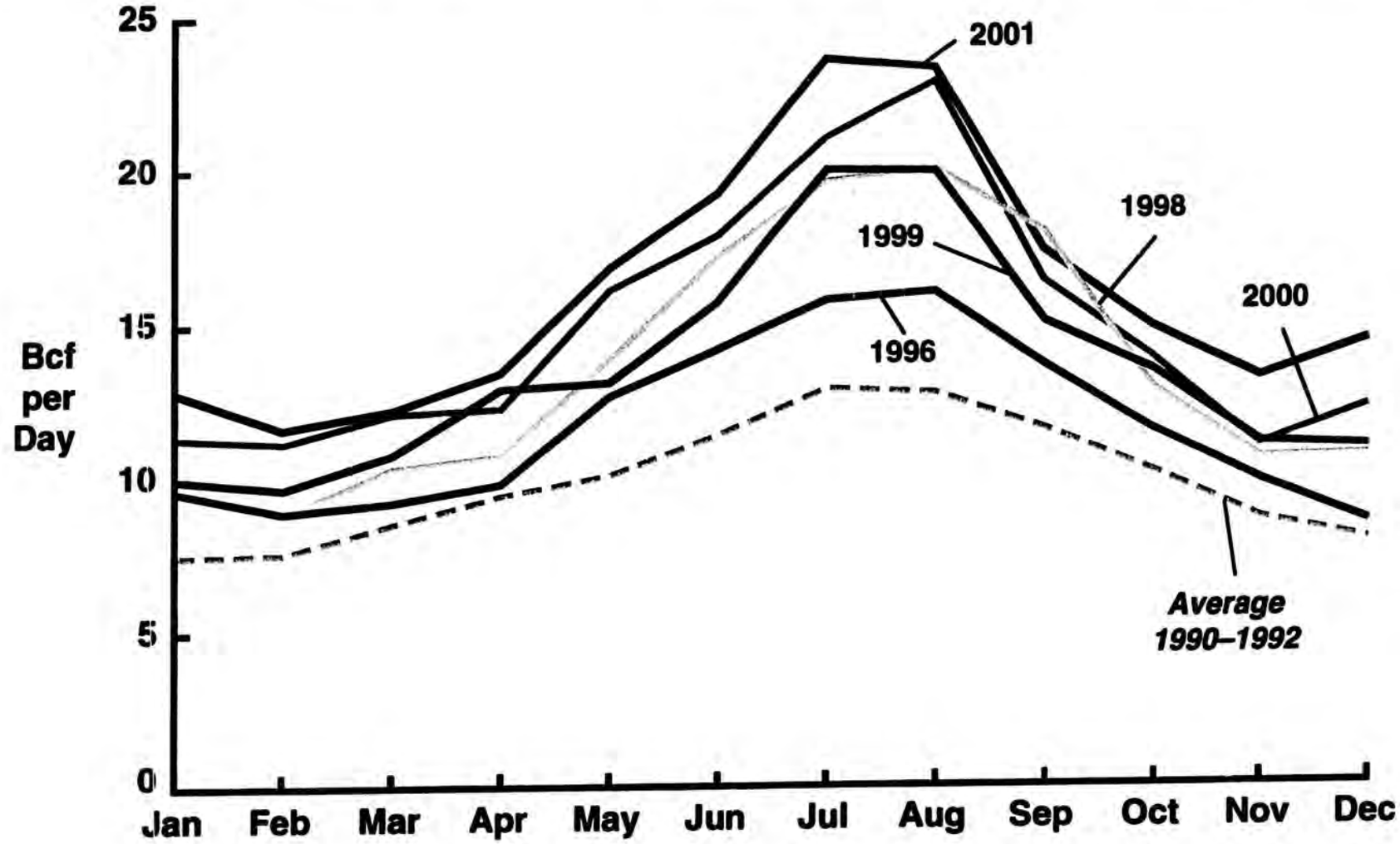
The US Summer Power Peak: Gas Demand for Power Generation



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Source: Cambridge Energy Research Associates.

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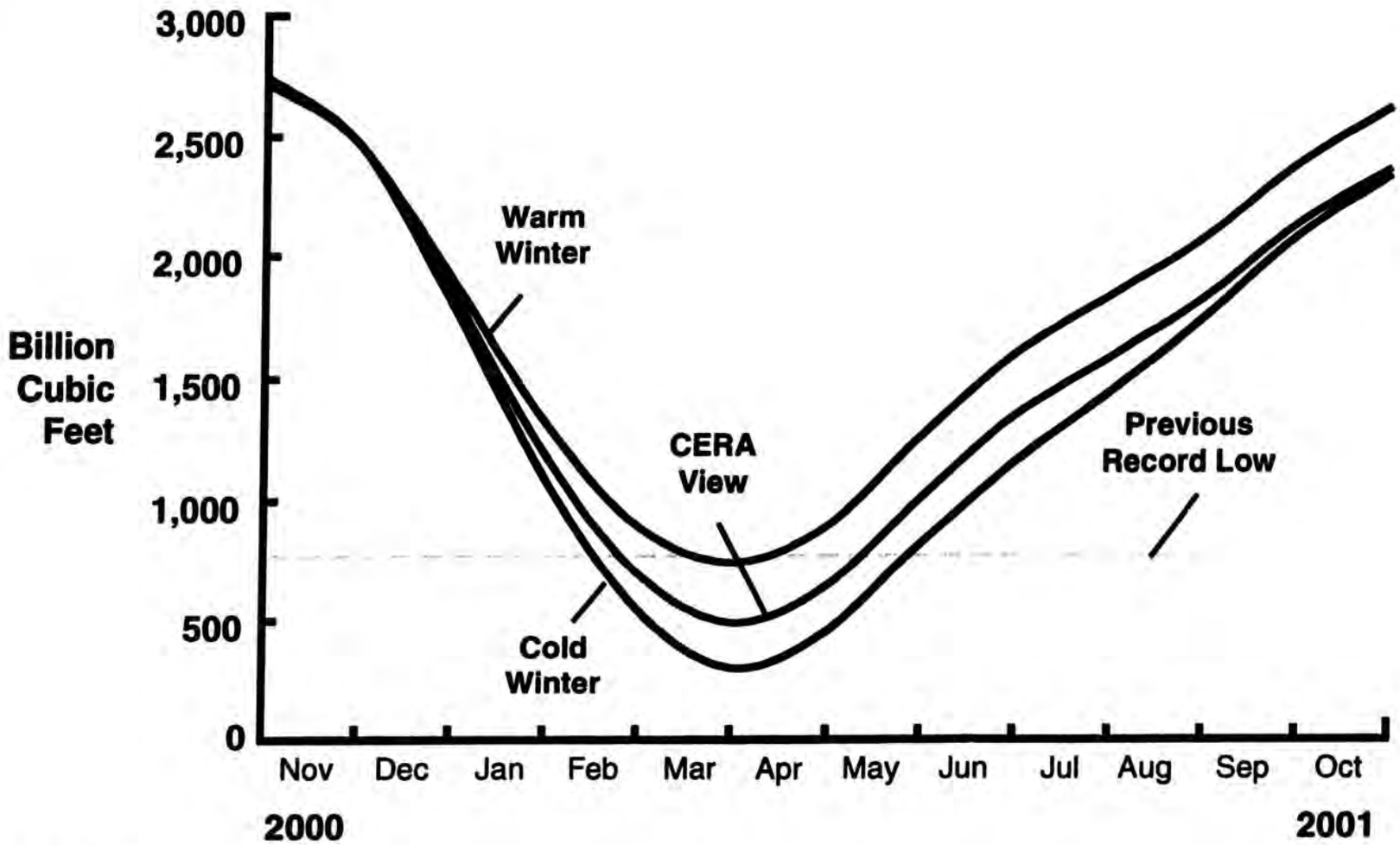
The Winter and Beyond— Depleted Storage in the United States Keeps the Pressure On



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Source: Cambridge Energy Research Associates.

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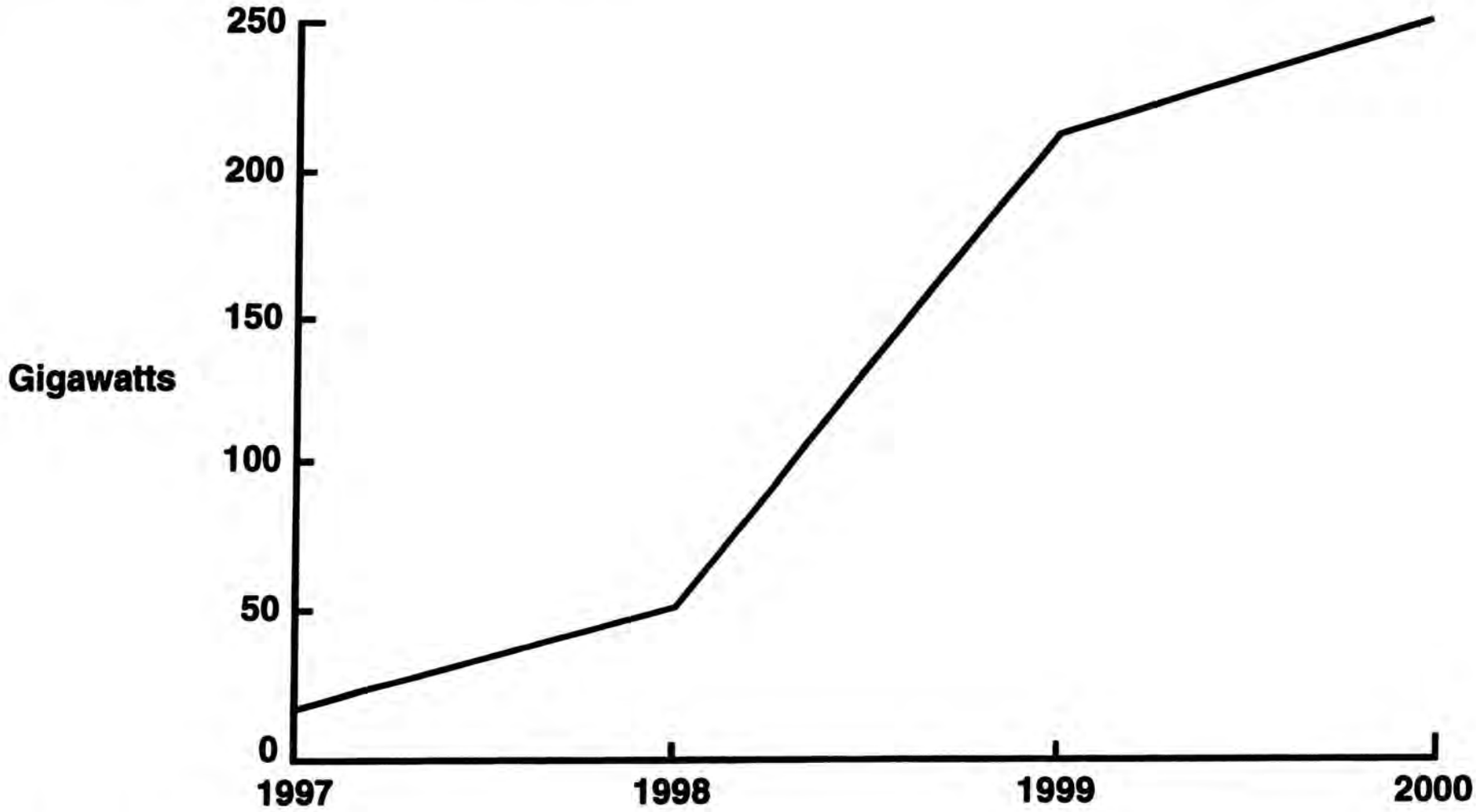
North American Generating Capacity under Development, 1997–2000



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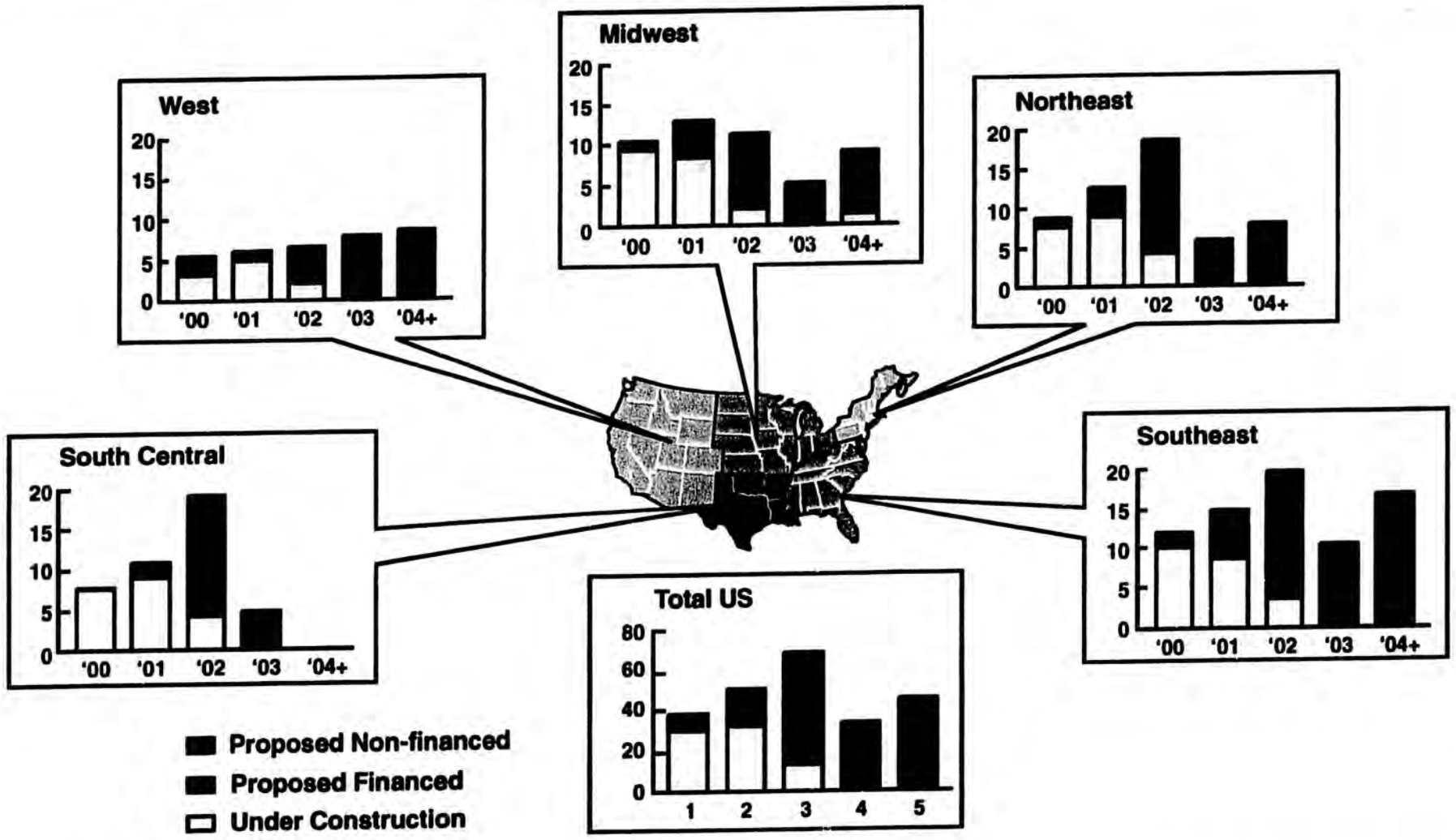
Source: Cambridge Energy Research Associates

Pressure in the Pipelines: The Potential Gas-fired Power Build by Region (gigawatts)



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Source: Cambridge Energy Research Associates.

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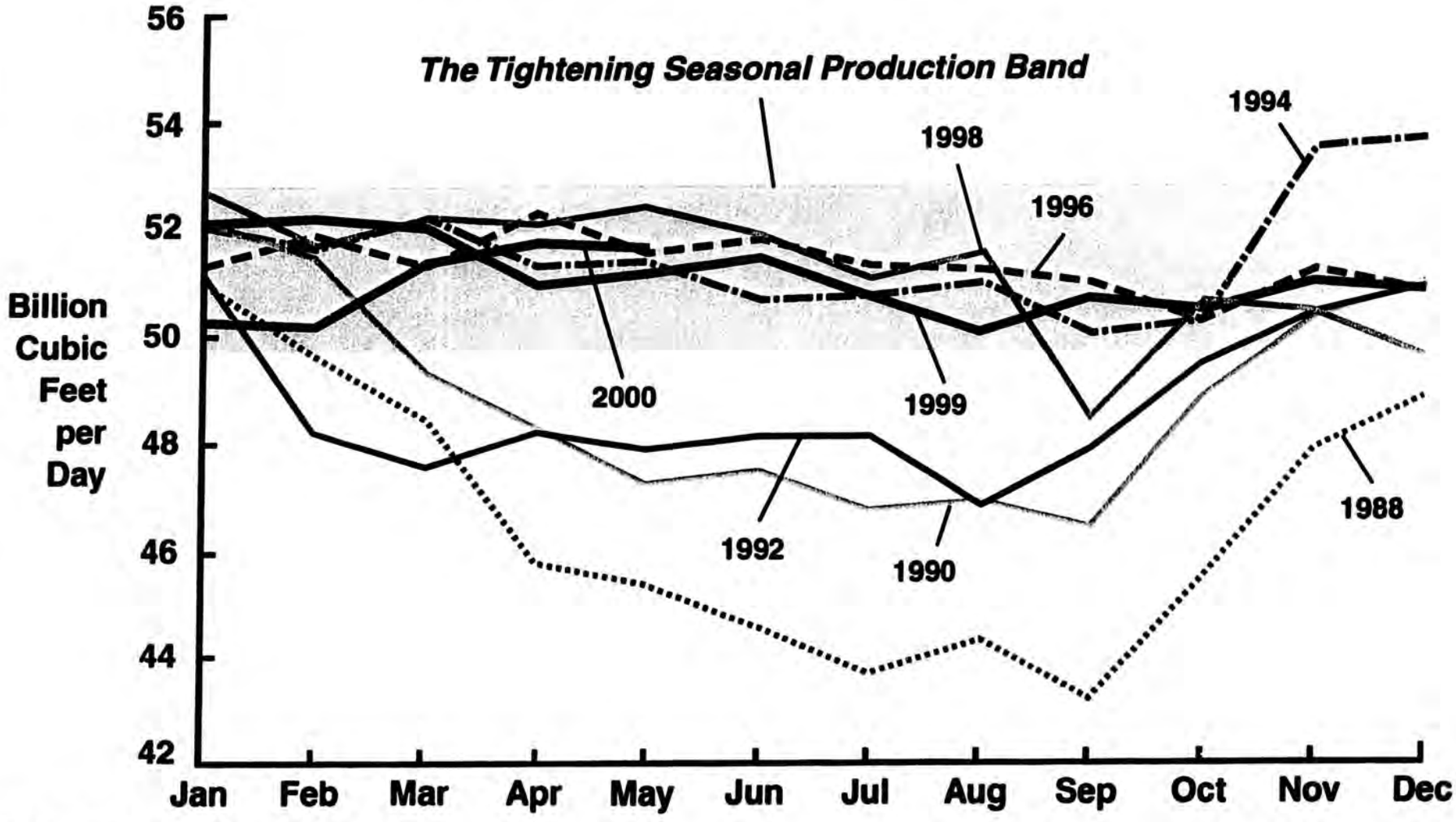
Flattening Seasonal US Production Constrains the Seasonal Supply Response



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Source: Cambridge Energy Research Associates.

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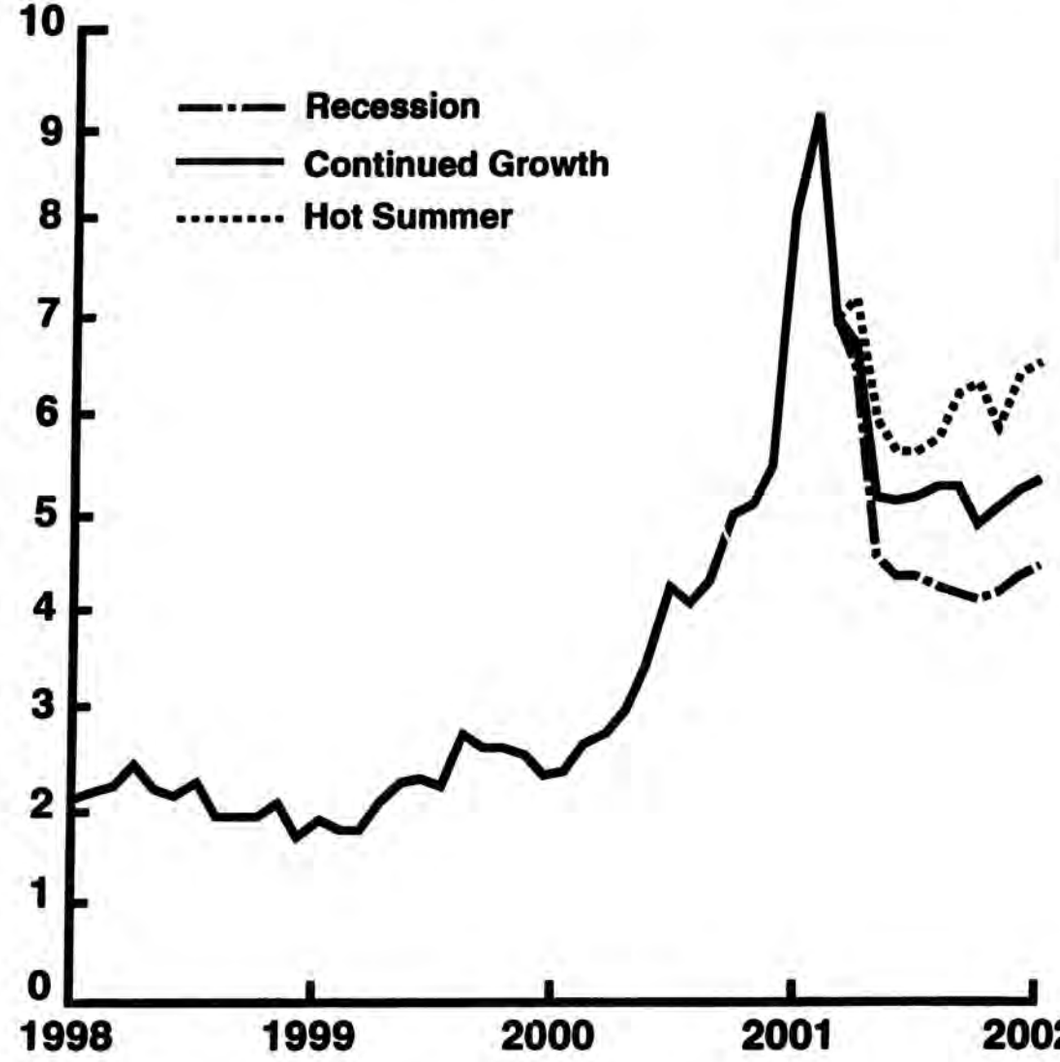
Henry Hub Price Projections



2001 Average		
Hot Summer:		
$4.23	$6.49	
Continued Growth:		
$4.23	$5.80	$3.91
Recession:		
$4.23	$5.15	

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Source: Cambridge Energy Research Associates.

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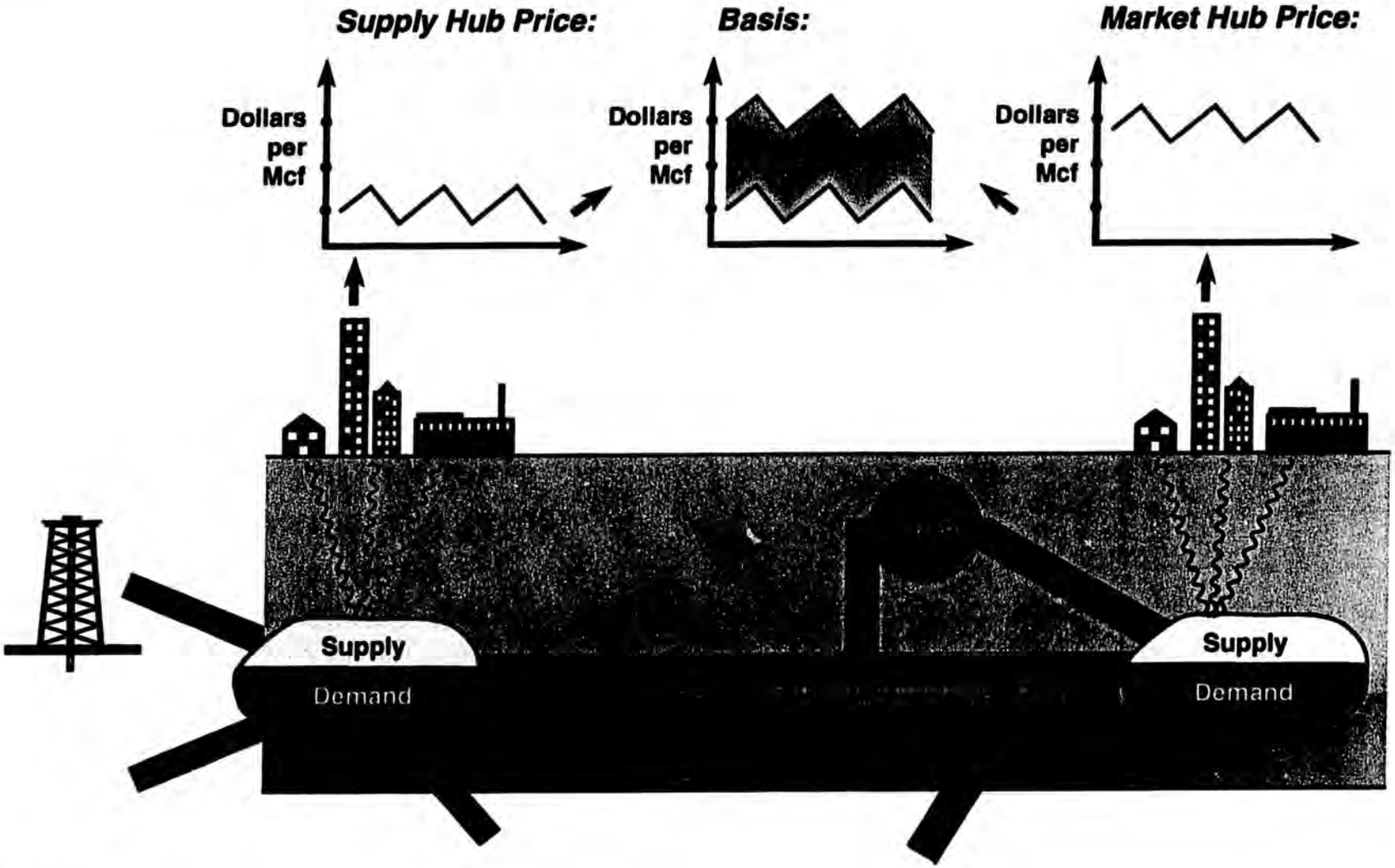
The Fundamental Drivers of Basis



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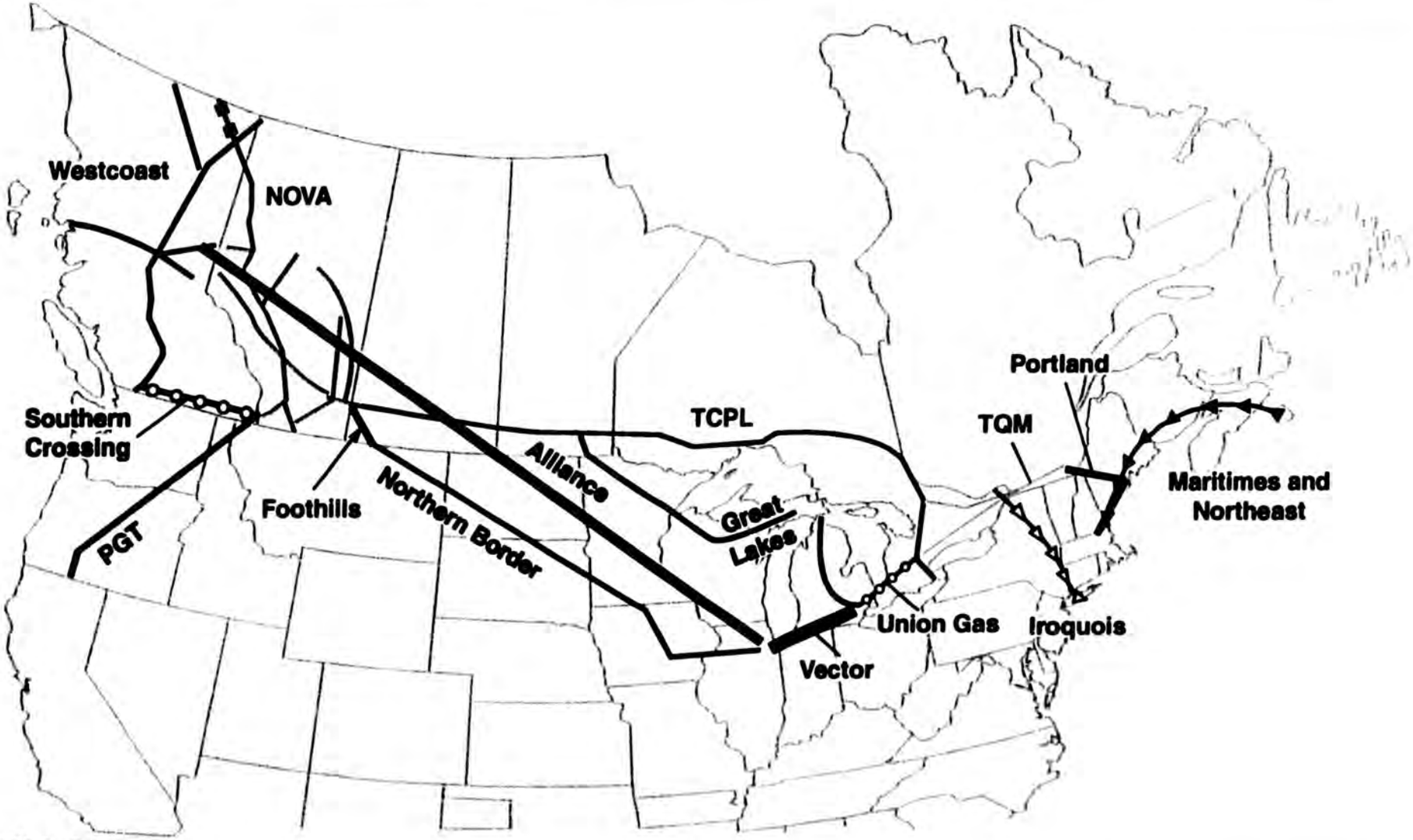
Source: Cambridge Energy Research Associates

Canadian Natural Gas Pipeline Infrastructure



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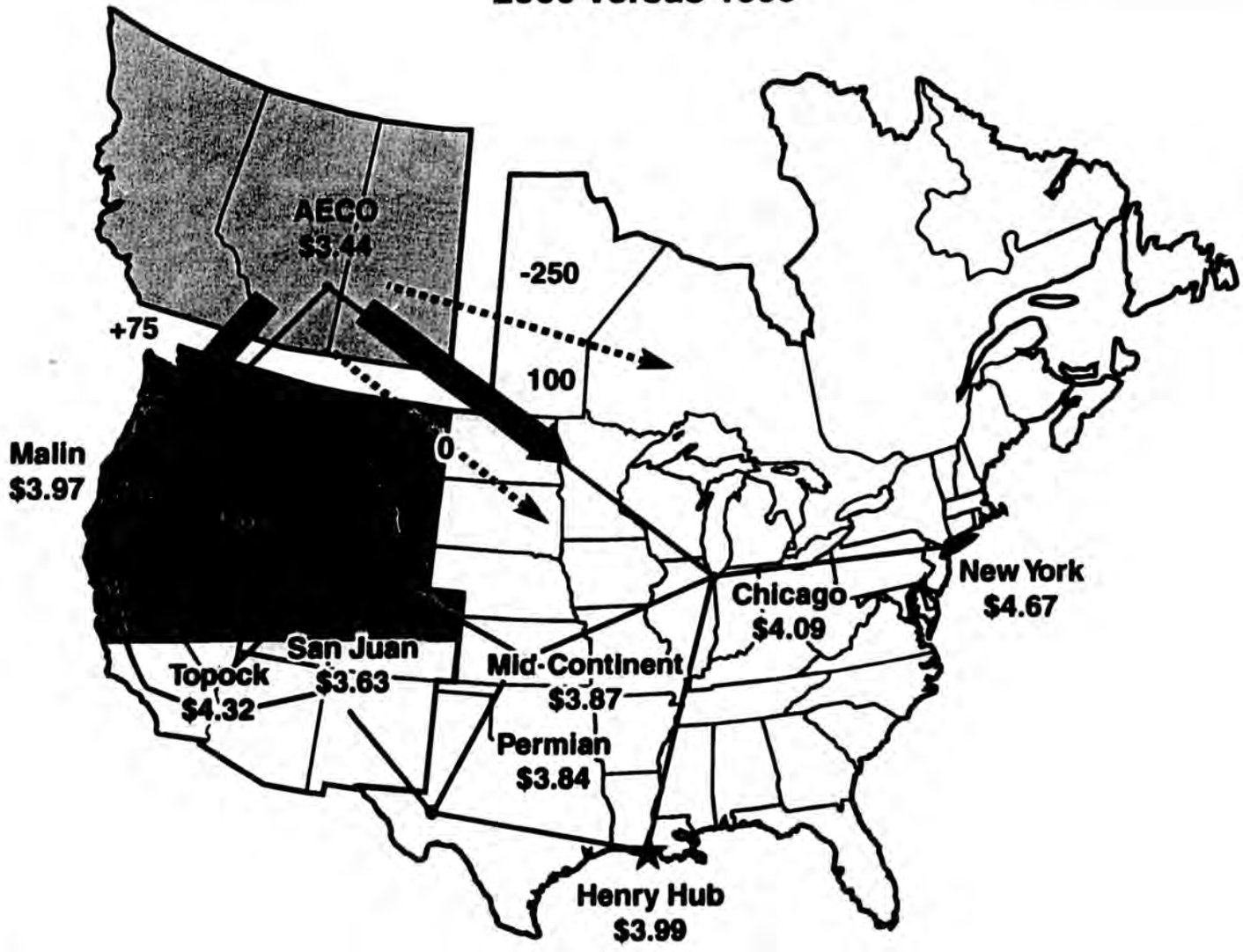
Source: Cambridge Energy Research Associates.

Changes in Export Flows
(MMcf per day; US dollars per MMBtu) (1 of 2)

2000 versus 1999



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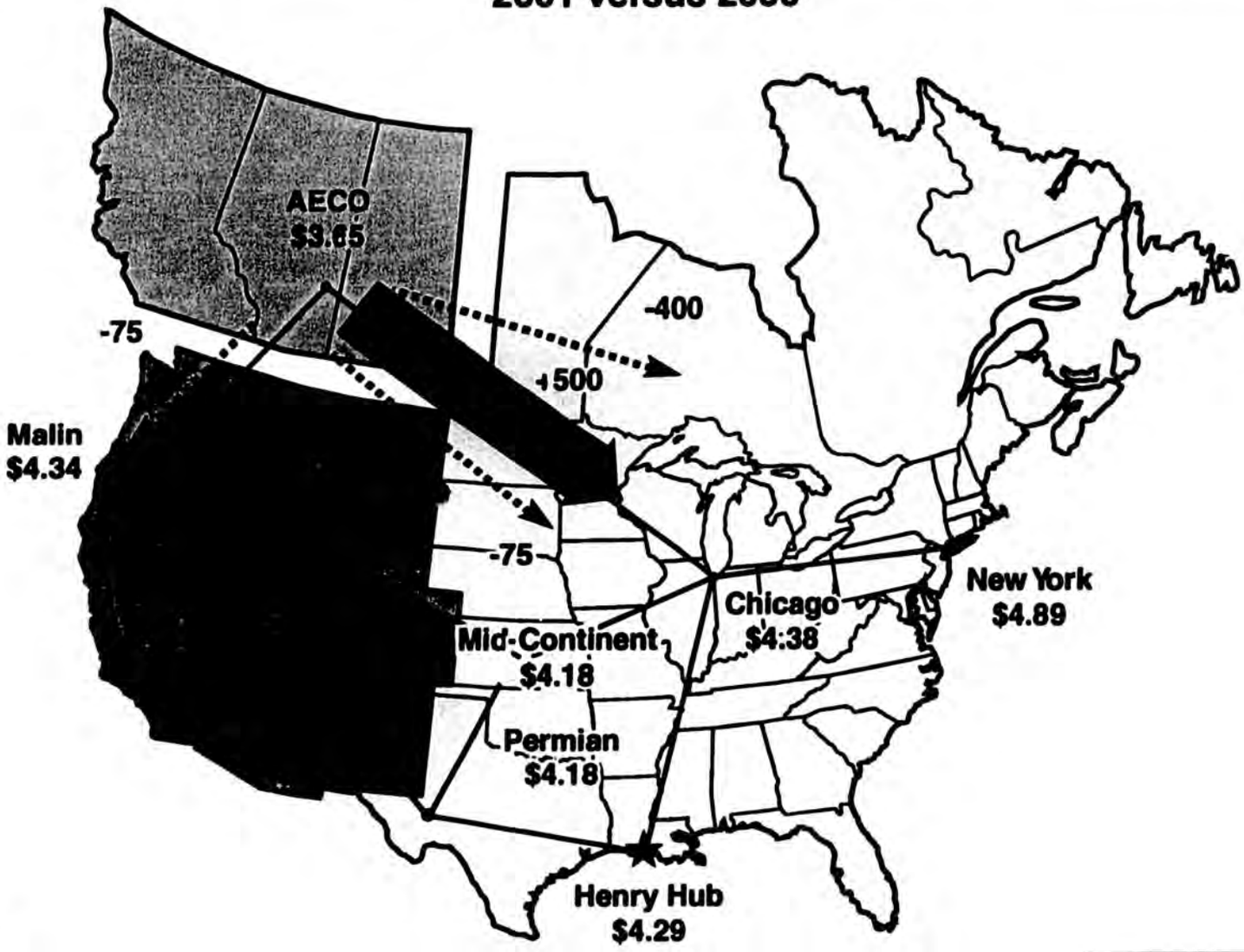
Changes in Export Flows
(MMcf per day; US dollars per MMBtu) (2 of 2)

2001 versus 2000



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Source: Cambridge Energy Research Associates

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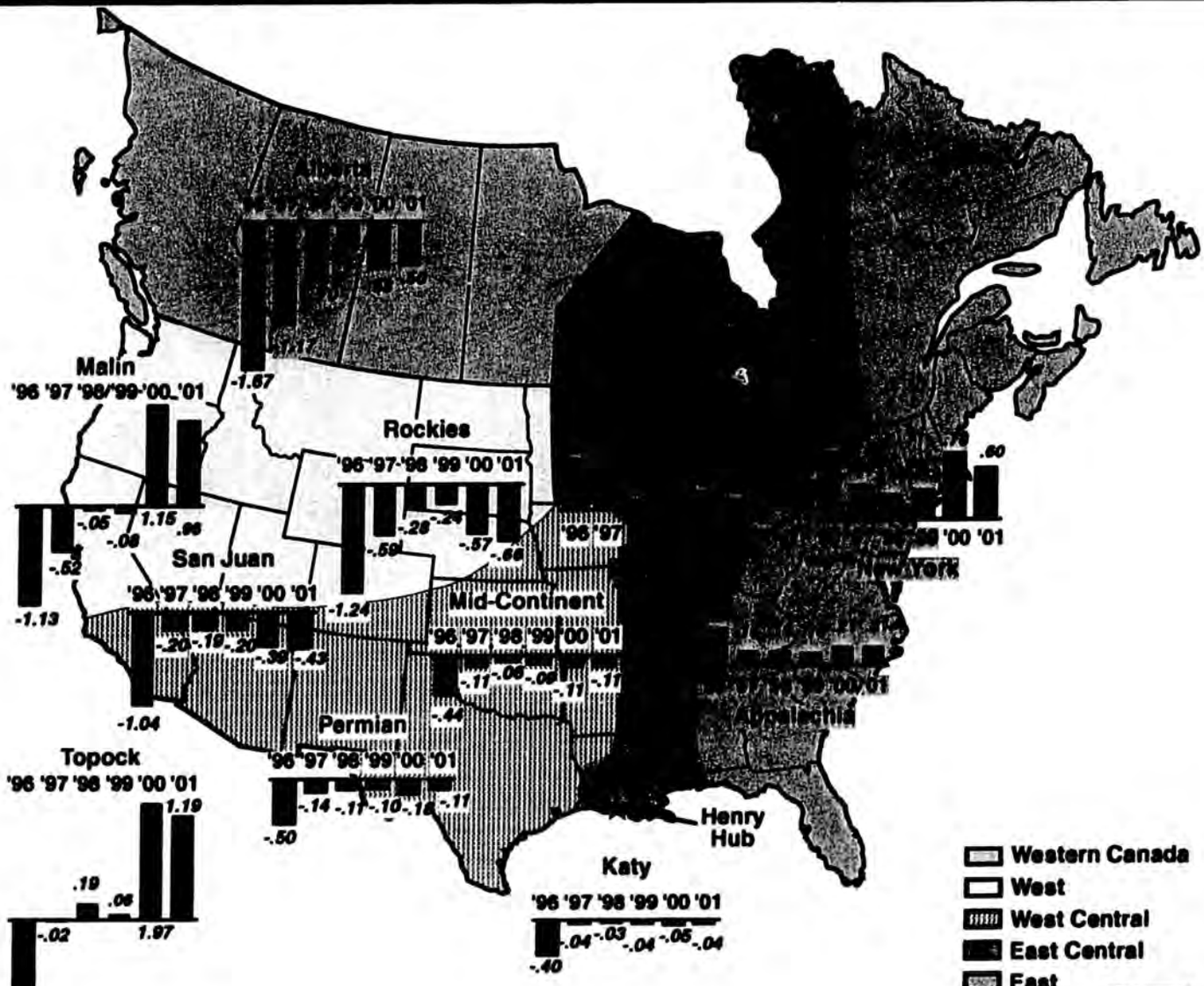
Natural Gas Key Regions of Basis Differentials: Price Differentials to Henry Hub (US dollars per MMBtu)



Source: Cambridge Energy Research Associates
Note: Supply Realignment case.

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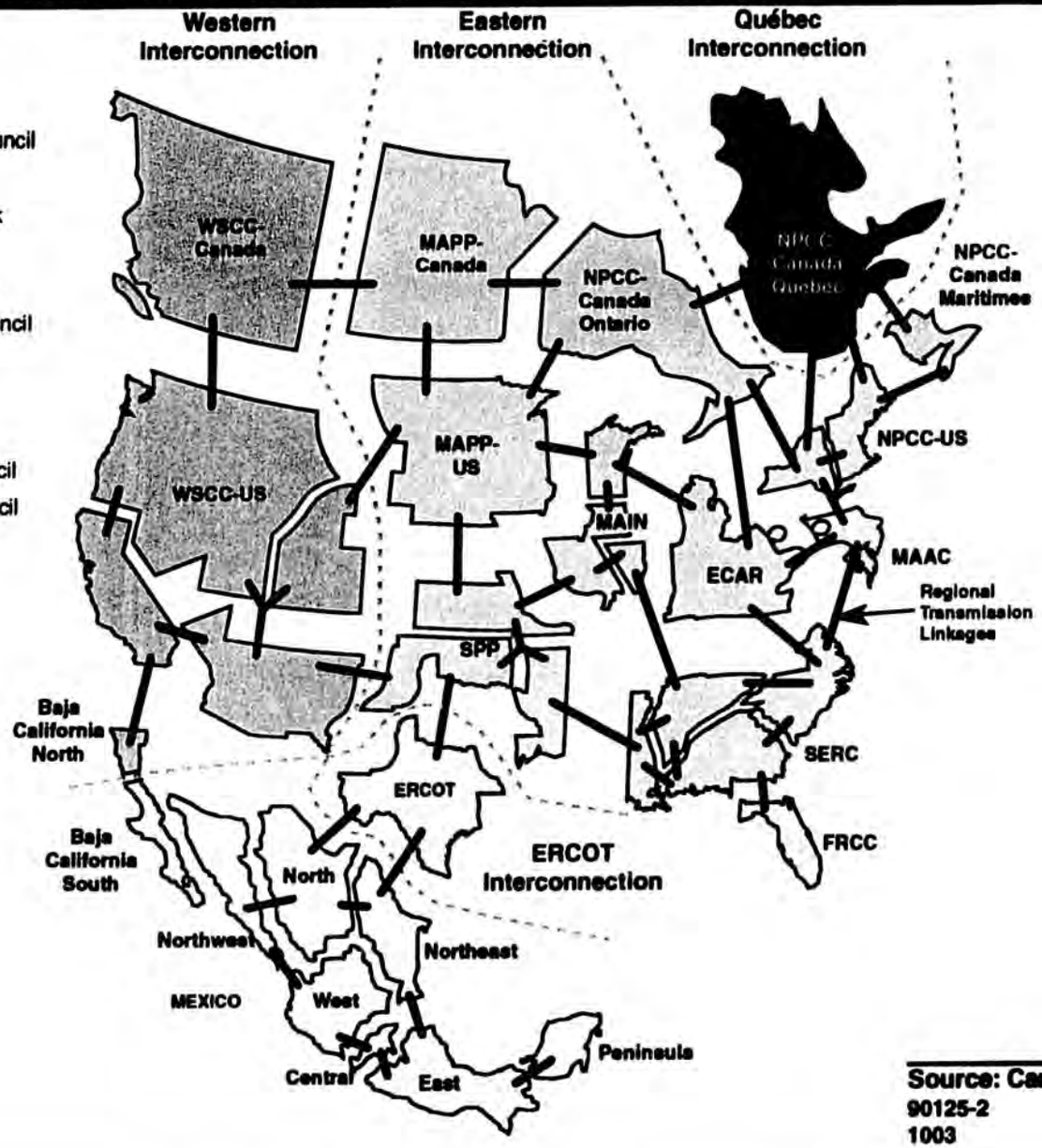
How Big Is the Market? Balkanization in Bulk Power Systems

SERC: Southeastern Electric Reliability Council
MAAC: Mid-Atlantic Area Council
MAIN: Mid-America Interconnected Network
SPP: Southwest Power Pool
ERCOT: Electric Reliability Council of Texas
WSCC: Western Systems Coordinating Council
ECAR: East Central Area Reliability Coordination Agreement
MAPP: Mid-Continent Area Power Pool
NPCC: Northeast Power Coordinating Council
FRCC: Florida Reliability Coordinating Council



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Source: Cambridge Energy Research Associates.
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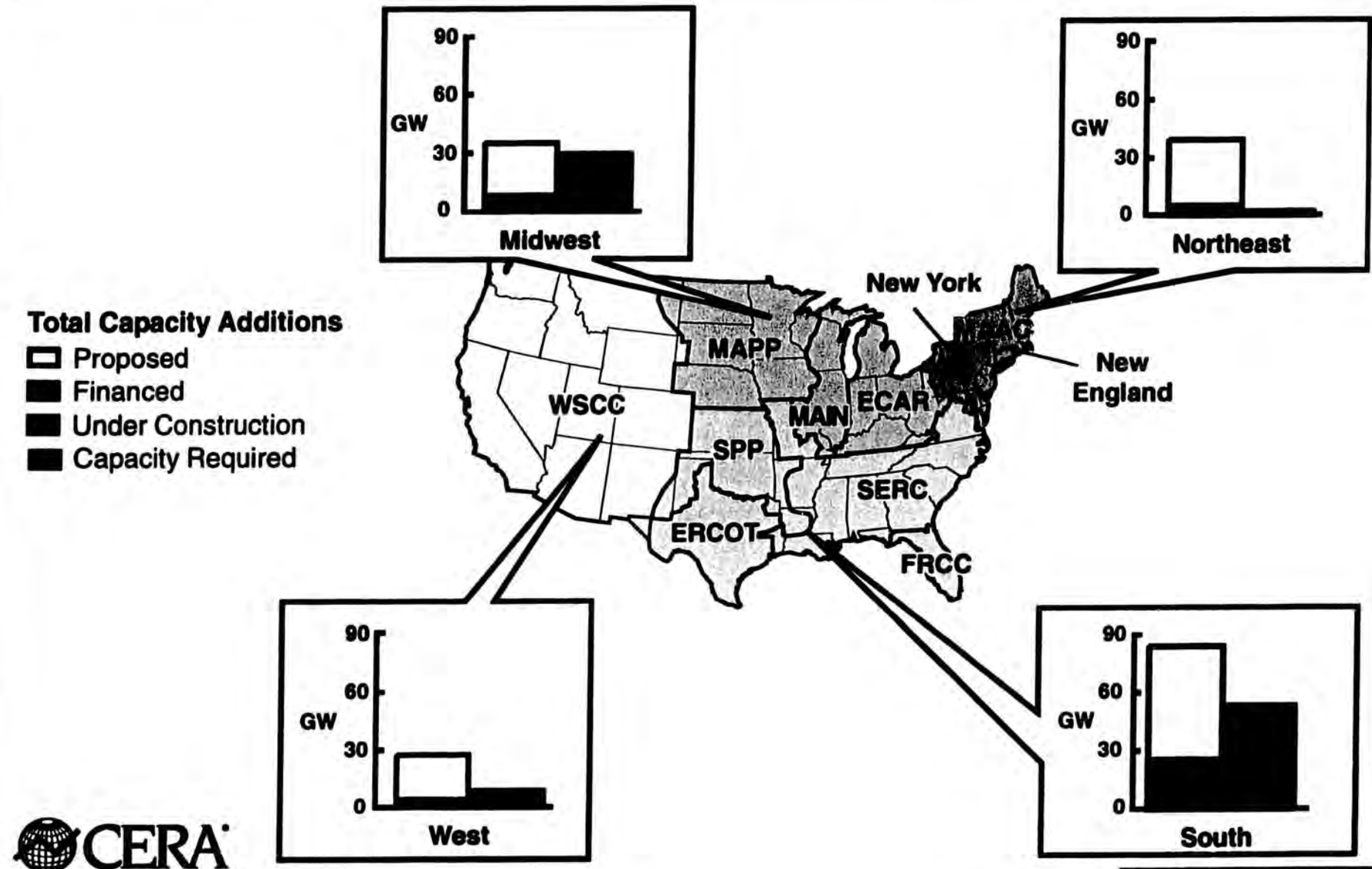
1003

New Electric Capacity Requirements versus Proposed Capacity Additions, 2000–2005



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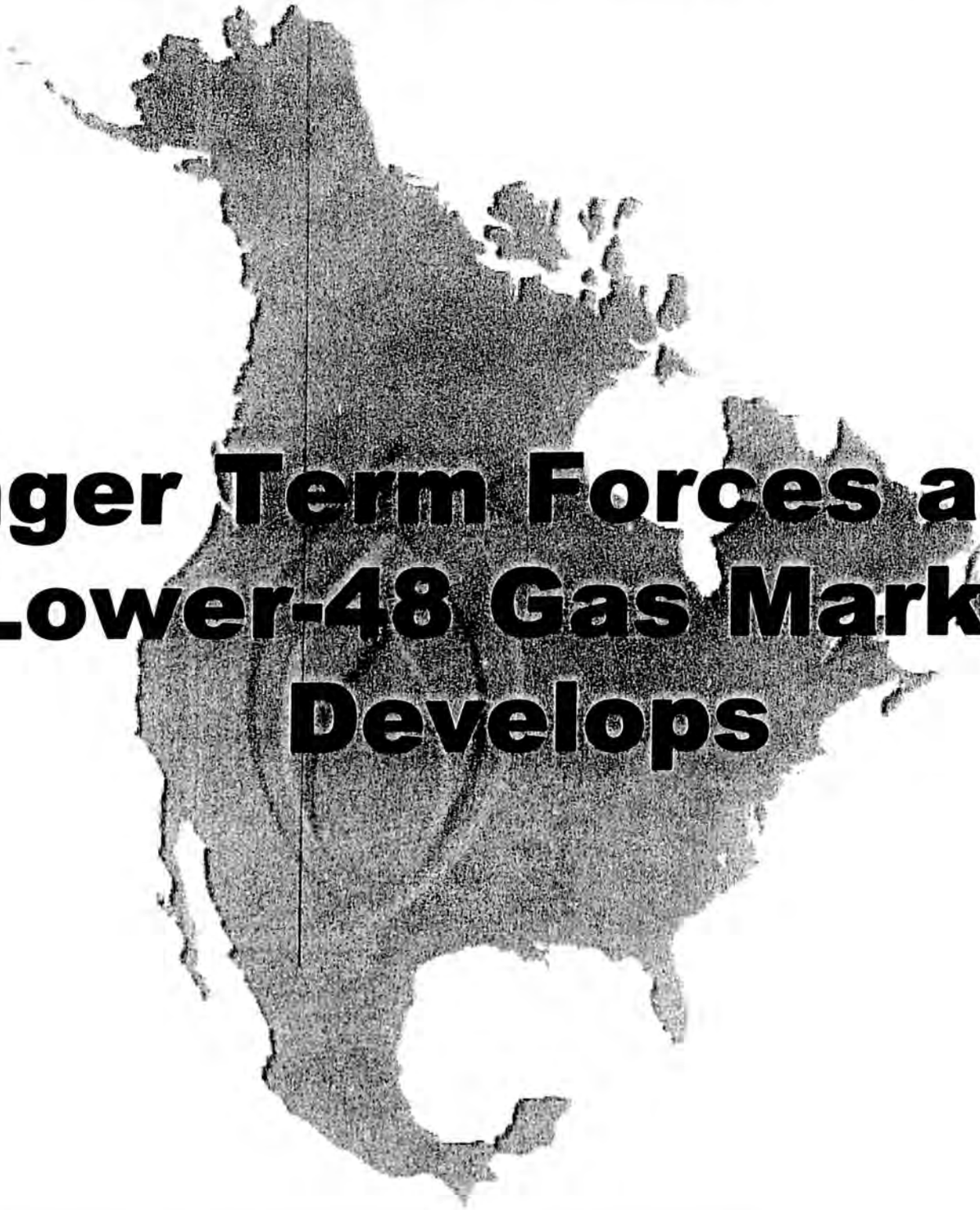
Source: Cambridge Energy Research Associates.



Longer Term Forces as the Lower-48 Gas Market Develops

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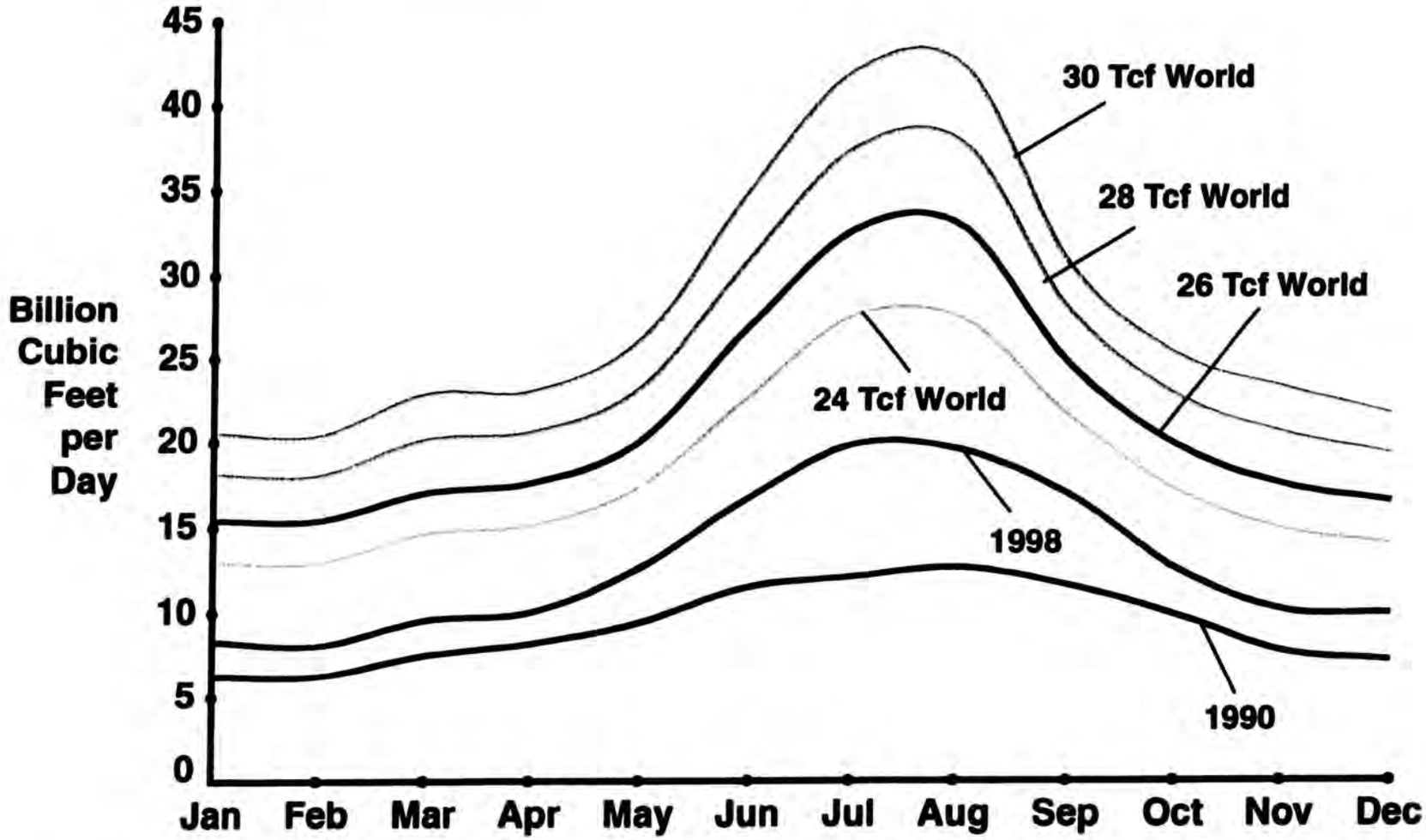
The Rise of the Summer Power Peak in the 30 Tcf World



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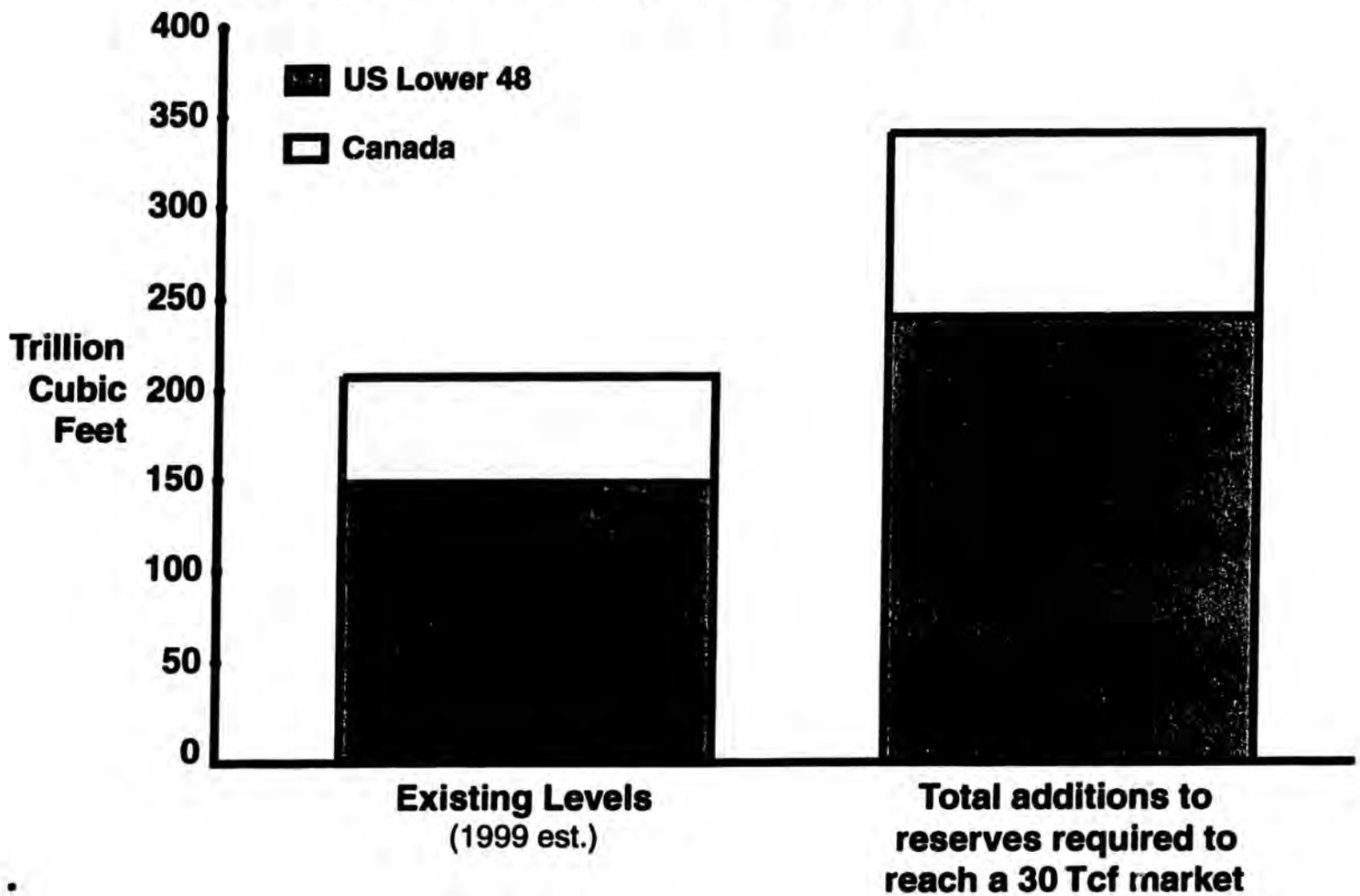
Source: Cambridge Energy Research Associates

The Challenge of Reaching 30 Tcf (1 of 2)

Reserve Additions Required, 2000 to 2010



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Source: Cambridge Energy Research Associates.

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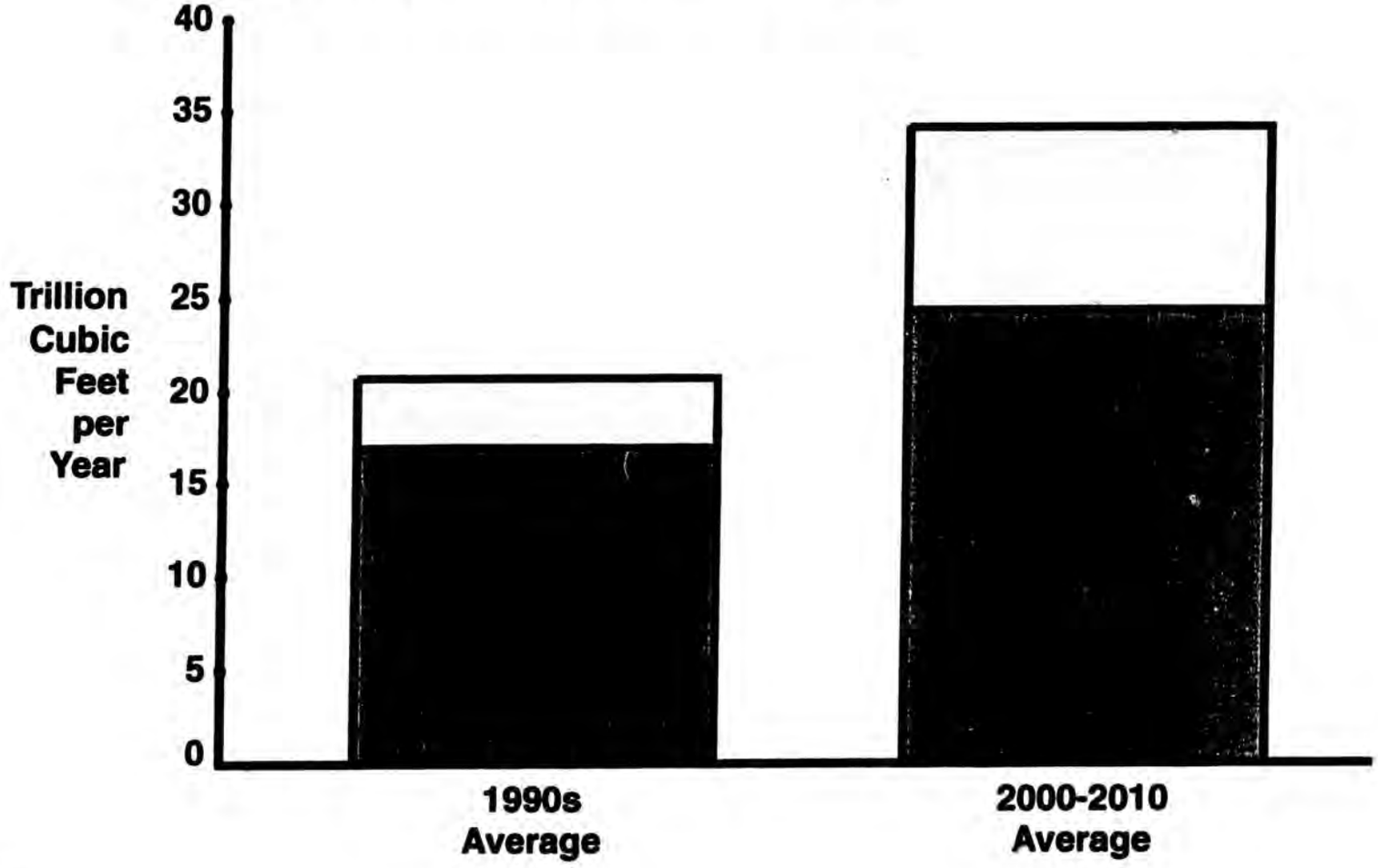
The Challenge of Reaching 30 Tcf (2 of 2)

Required Reserve Additions per Year



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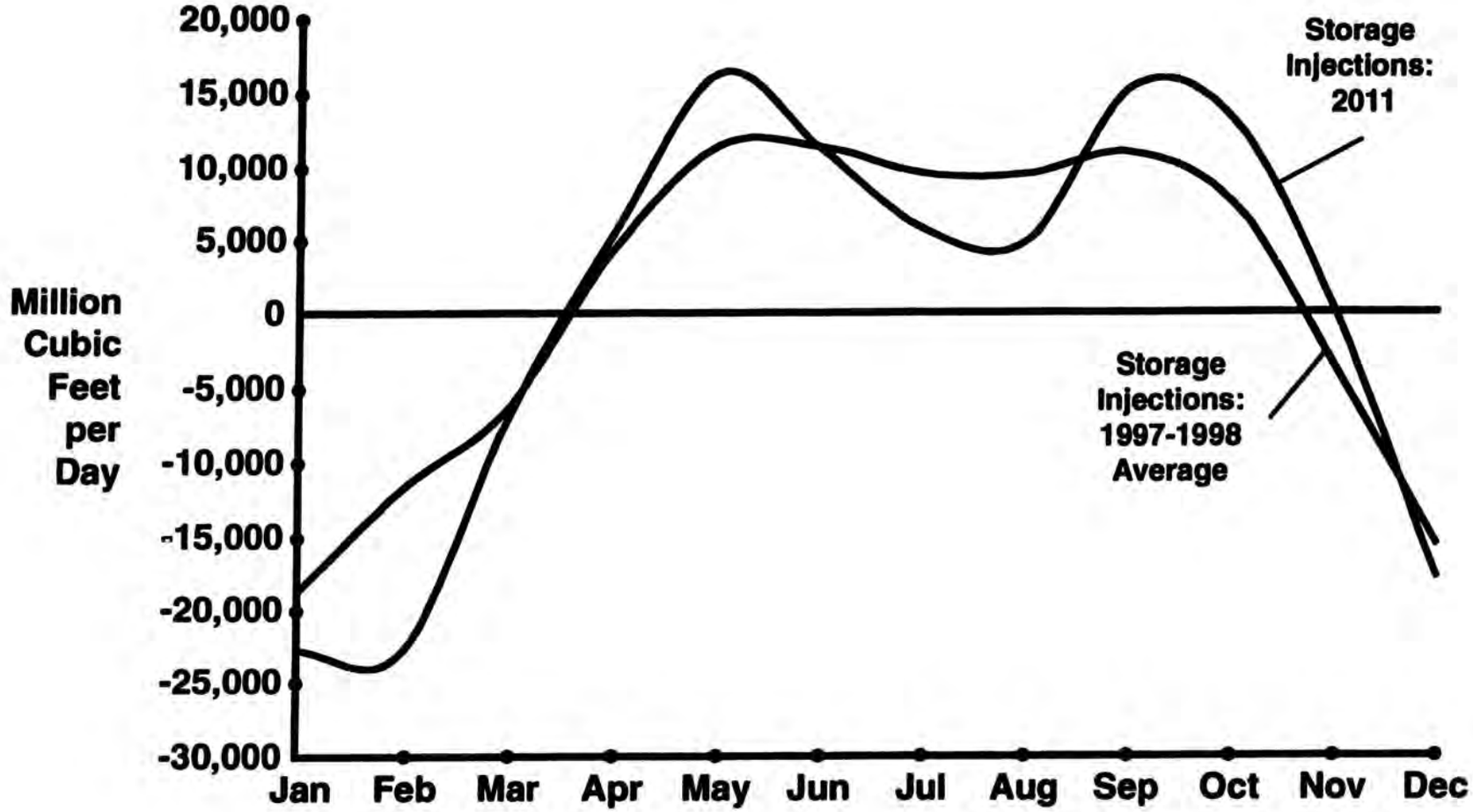
Source: Cambridge Energy Research Associates

Changing Storage Injection Patterns in a 30 Tcf World: US Lower-48



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Source: Cambridge Energy Research Associates.
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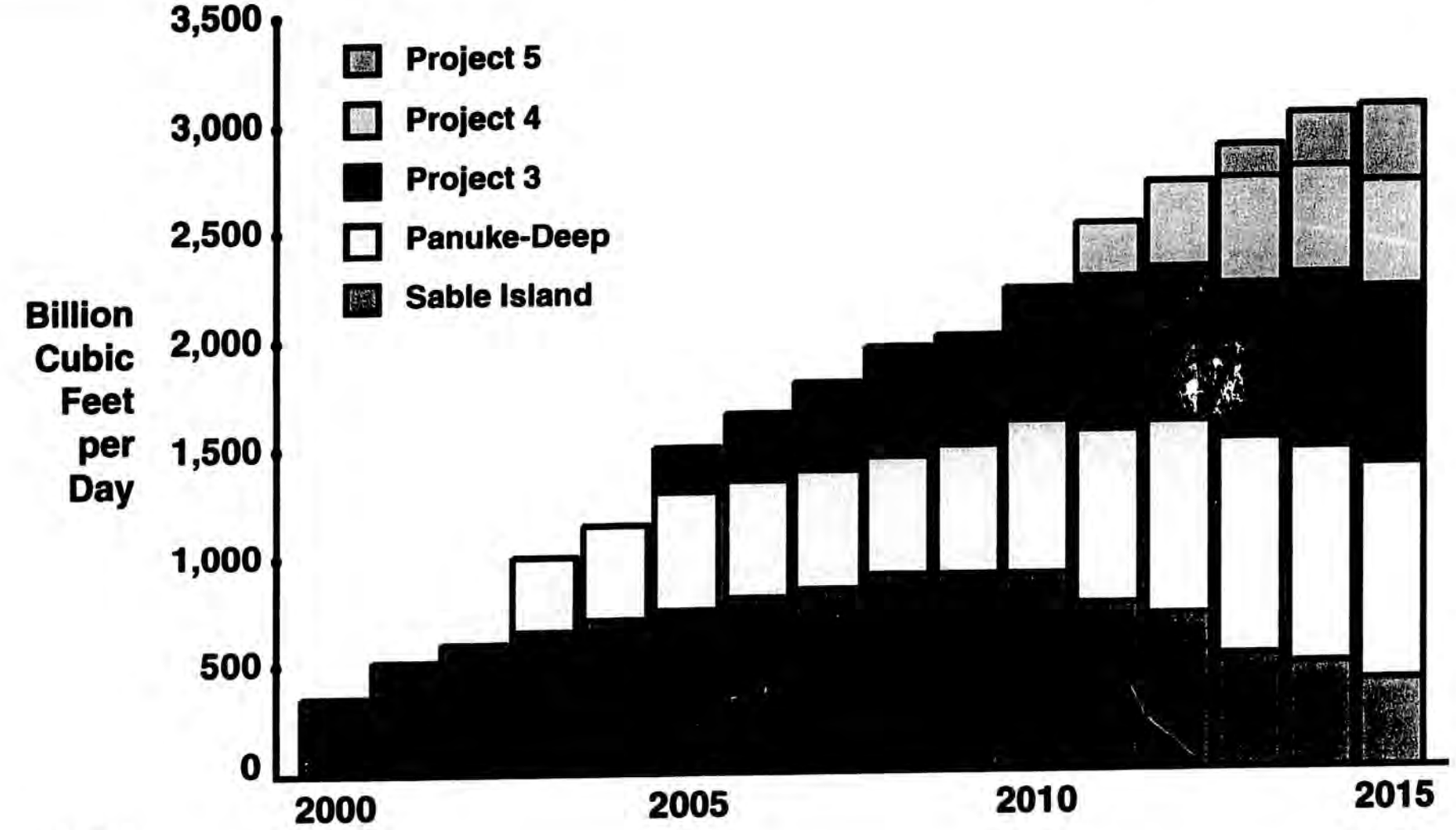
Scotian Shelf Supply Build



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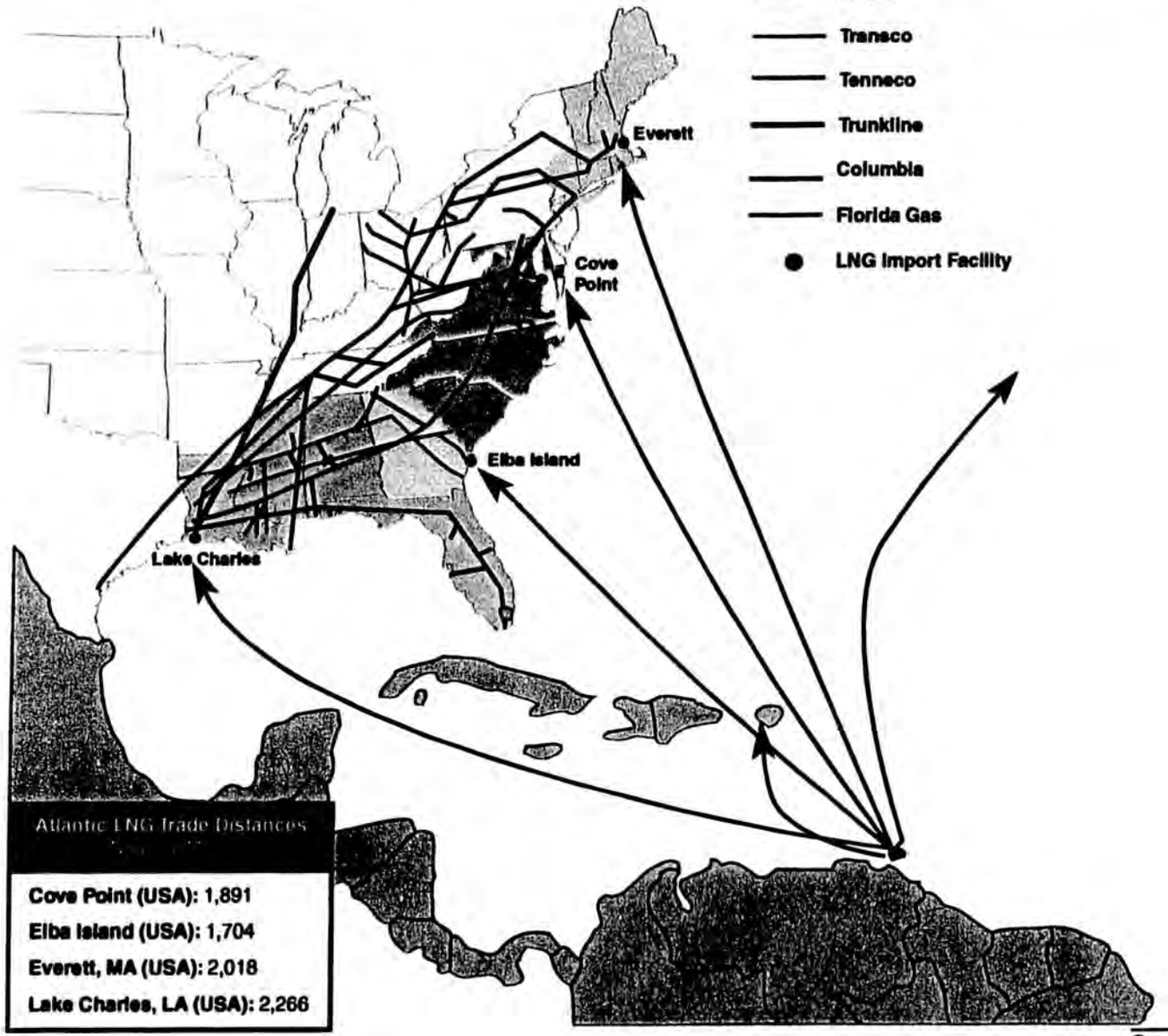
Source: Cambridge Energy Research Associates.

Potential US LNG Destinations for Atlantic LNG



Atlantic LNG Trade Distances

Cove Point (USA): 1,891
Elba Island (USA): 1,704
Everett, MA (USA): 2,018
Lake Charles, LA (USA): 2,266

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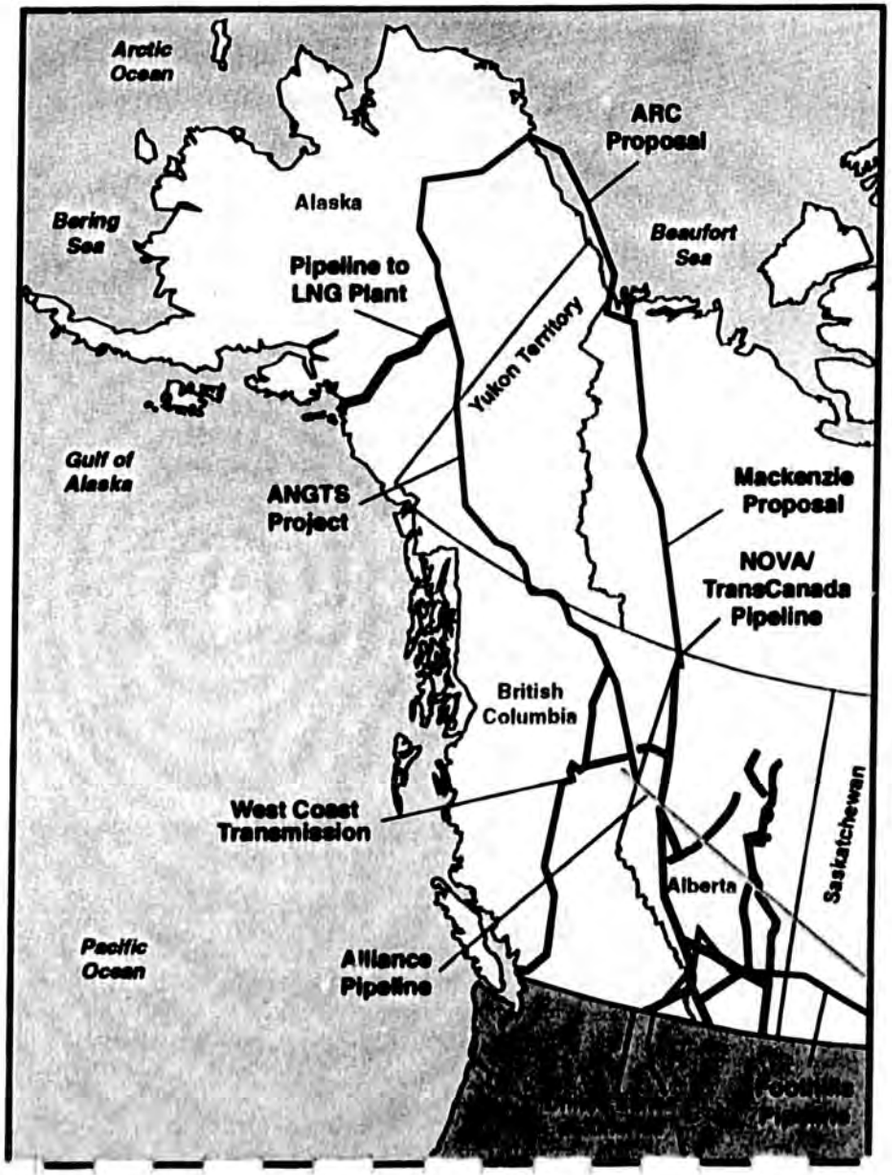
Source: Cambridge Energy Research Associates
00520-5

Arctic Gas Pipeline Alternatives



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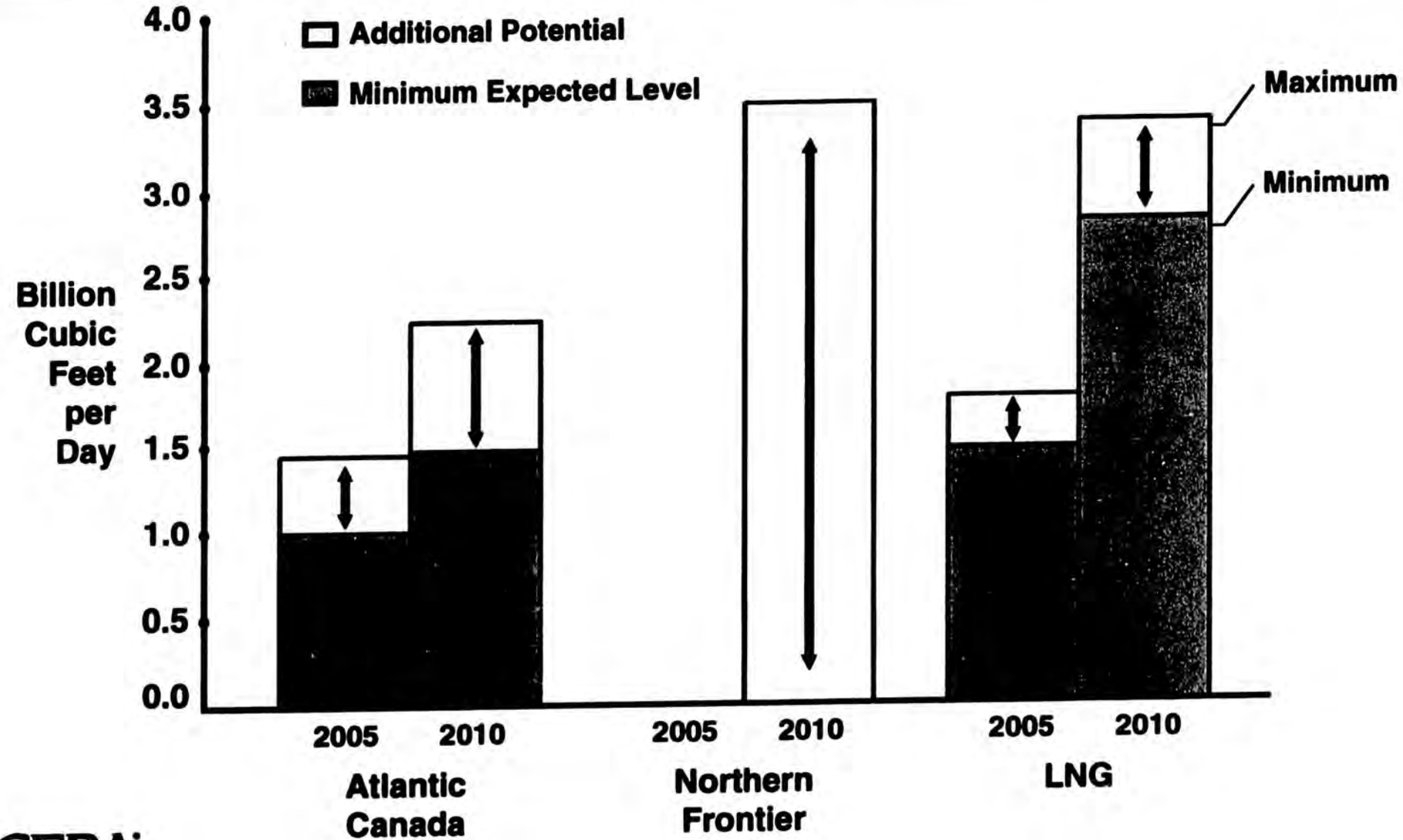
Source: Cambridge Energy Research Associates

The Range of Production Levels from Frontier Areas



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Source: Cambridge Energy Research Associates.

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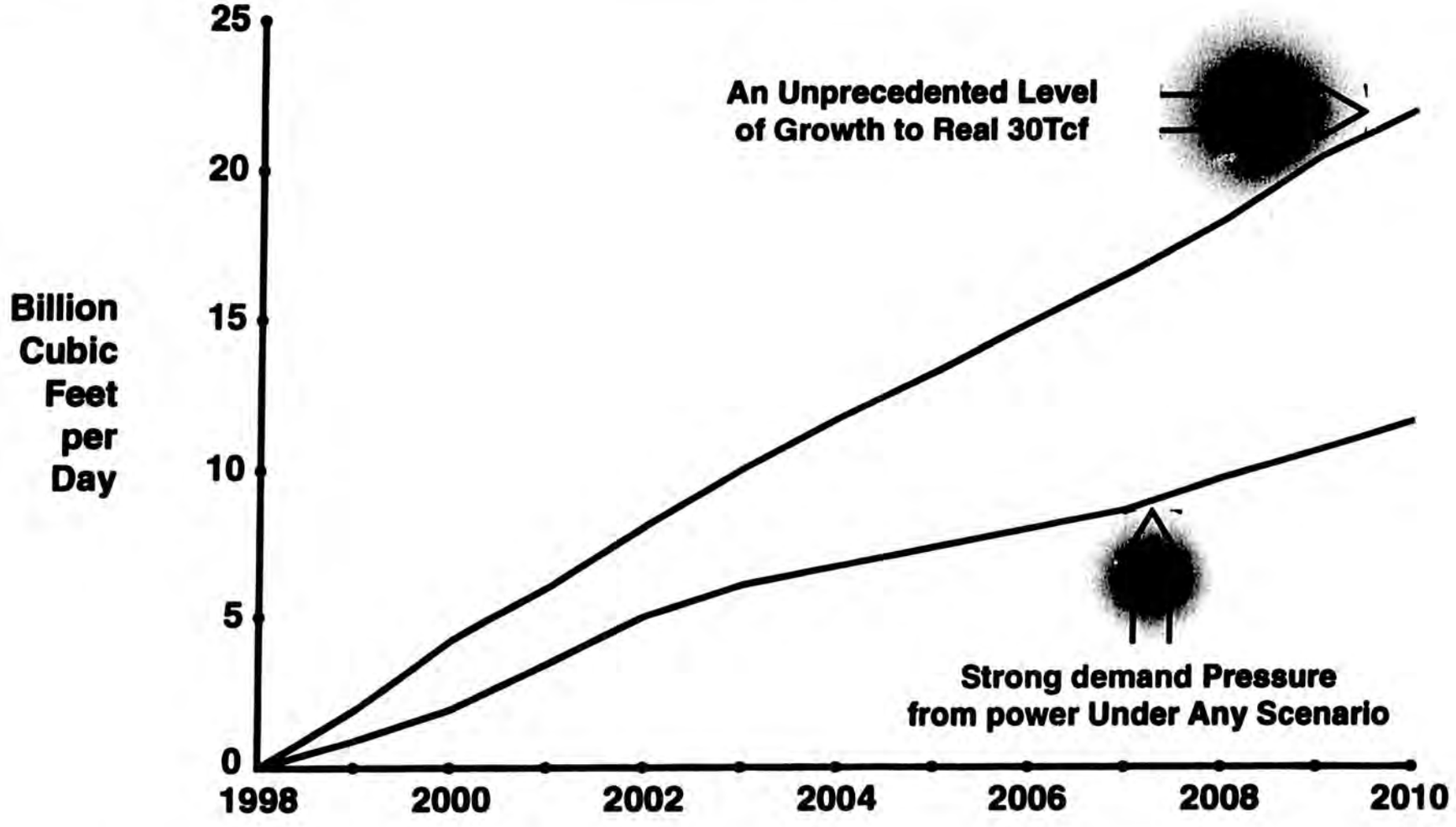
30 Tcf: More Plausible Than Probable—The Range of Natural Gas Demand Growth Relative to 1998



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Source: Cambridge Energy Research Associates

Northern Gas Pipeline Development Risks (1 of 2)



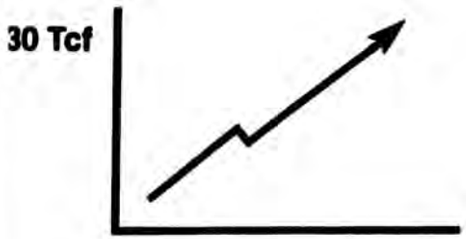
Gas Pricing

- Sustained Minimum $2.50 to $3.00 Needed



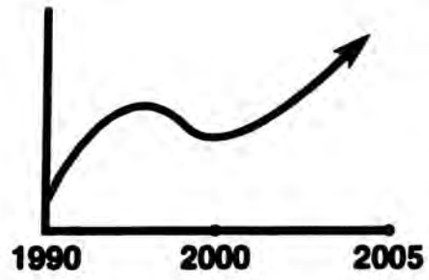
Political Intervention

- US and Canadian Government Positions on International Agreement
- Potential Delays Due Native Settlements Issue
- "In-fighting" Between Regional Governments



Market Growth

- Continued Economic Growth Essential
- Fits with a 30 Tcf World
- Contraction from high Prices Detrimental



Supply Growth

- Resurgence from Other Regions Detrimental
- Coalbed Methane from Western Canada Negative Factor



Downstream Capacity

- Excess Capacity Out of the West
- New Capacity all the way to Markets

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Source: Cambridge Energy Research Associates

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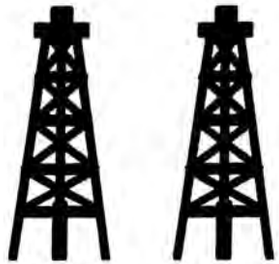
Northern Gas Pipeline Development Risks (2 of 2)



Construction Delays

- Weather
- Equipment
- Workers



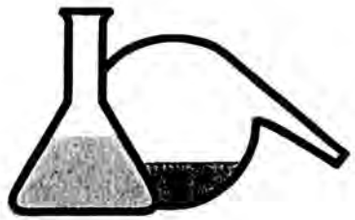
Resource Development

- Ultimate Capability
- New Sources



Risk Sharing

- Pipelines
- Producers
- Markets
- Financial Backing



Liquids

- Disposition
- Increase Economic Viability



Contracts

- Security
- Term Length
- Volume

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Source: Cambridge Energy Research Associates



LNG Market Potential: Key Drivers

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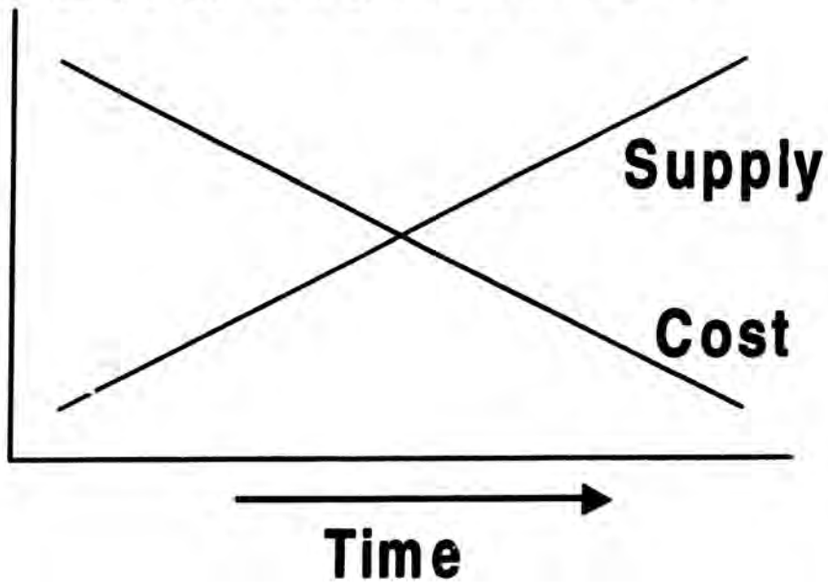
Why Now?

LNG Transitions



- **Fundamental changes are taking place in**
  - LNG costs
  - Available supplies
  - Industry structure
- **How will changes unfold in the future?**

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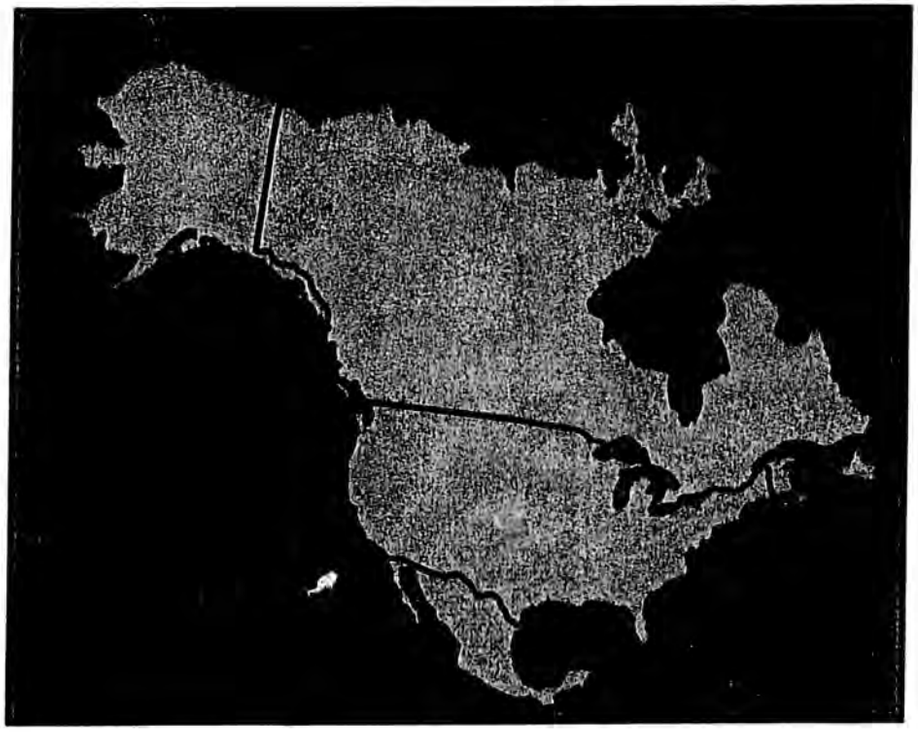
Why Now?



- **High US prices and tight North American supplies have reinvigorated US LNG imports, but will these conditions last?**

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Why Now?



- **Economic recovery and new markets mean strong growth in Asia, but how strong?**

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World LNG Facilities



- Existing LNG projects and those under expansion or initial development
- LNG projects possible by 2005–2010
- LNG projects approved, but not under development
- G Proposed GTL project
- Countries likely to require initial LNG imports

January 2001

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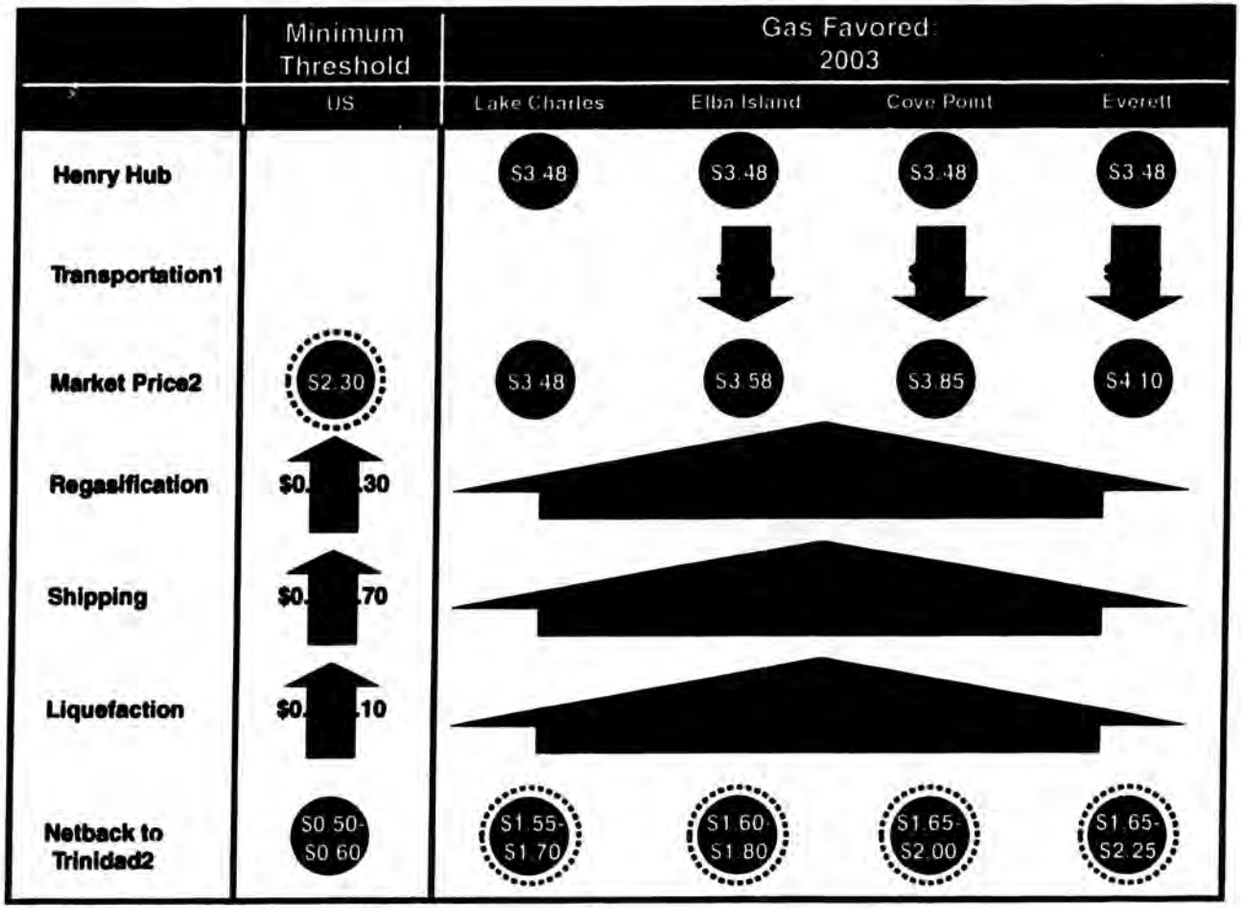
Supply Considerations

- Geography
- Supply Diversification/Security Concerns
- Associated Gas Pressures
- Liquids Revenue Stream
- Gas Monetization

The LNG Value Chain



Source: Cambridge Energy Research Associates.

Notes: 1. These figures represent annual average spot differentials between the Henry Hub and the respective citygates (Atlanta, Washington DC, and New England).

Notes: 2. All cost figures are CERA estimates. This schematic analysis omits any charges for transporting the regassified fuel to the relevant market hubs (this could range from $0.05 to $0.25 per MMBtu) as well as any marketing fees.

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US LNG Import Facilities

Cove Point, MD (Reopening 2002/03)	
Operator:	**Cove Point LNG** (Williams)
Vaporization Capacity	1 Bcf per day (750 allocated for imports)
Storage Capacity	5 Bcf (expanding to 7.5 Bcf)
Number of Tanks	4
Tanker Berths	2
Draft	11 meters
Pipeline Connections	Columbia Gas, Transcontinental

Everett, MA (Operating)	
Operator:	**Distrigas LNG** (Tractebel)
Vaporization Capacity	435 MMcf per day (expanding to 600 MMcf per day in mid-2001)
Trucking Capacity	100 MMcf per day
Storage Capacity	3.6 Bcf
Number of Tanks	2
Tanker Berths	1
Draft	11 meters
Pipeline Connections	Algonquin, Tennessee



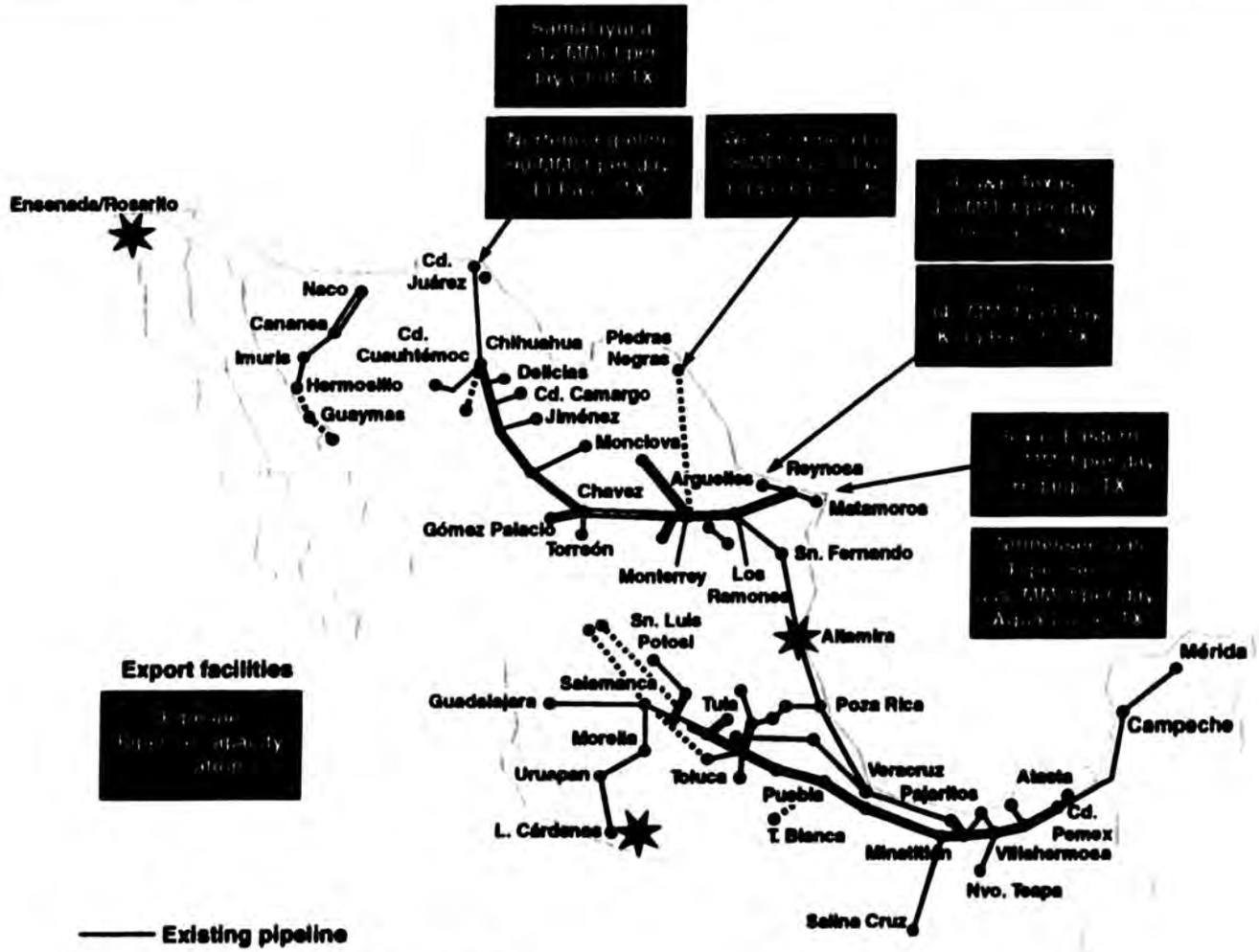
Lake Charles, LA (Operating)	
Operator:	**Trunkline LNG** (CMS)
Vaporization Capacity	700 MMcf perday (expanding to 1Bcf per day in mid-2001)
Storage Capacity	6.3 Bcf
Number of Tanks	3
Tanker Berths	1
Draft	12 meters
Pipeline Connections	Trunkline, Gulf Coast Pipes

Elba Island, GA (Reopening 2002/03)	
Operator:	**Southern LNG** (El Paso)
Vaporization Capacity	440 MMcf per day (maximum sendout is 675 MMcf per day)
Storage Capacity	4 Bcf
Number of Tanks	3
Tanker Berths	1
Draft	12 meters
Pipeline Connections	Southern Natural Gas

CERA

Source: Cambridge Energy Research Associates

Mexican Potential



CERA

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CERA

Alaska Highway Natural Gas Policy Council
Workshop Agenda

Friday, March 23, 2001
Anchorage Sheraton Hotel – 10:00 a.m. to 3:30 p.m.

I. Call to order/opening remarks, 10:00-10:30

II. Presentation from North American Natural Gas Pipeline Group, 10:30-11:30

III. Presentation on the Canadian perspective, 11:30-12:15
Jeff Smith, Senior Vice Pres., Public Affairs, Hill and Knowlton, Ottawa

IV. Break/sandwich buffet, 12:15-12:45

V. Presentation on the Federal perspective, 12:45-1:45
Bob Loeffler, Senior Partner, Morrison and Foerster, Washington, DC

VI. Presentation on the State agency perspective, 1:45-2:30
A. Bill Britt, Coordinator, Joint Pipeline Office
B. Mark Myers, Director, Division of Oil and Gas

VII. Ten minute break, 2:30-2:40

VIII. Council Business – Sampson/Brown, 2:40-3:30
A. Approve public hearing/meetings schedule
B. Discuss public hearing format
C. Discuss subcommittee work

North American Natural Gas Pipeline Group

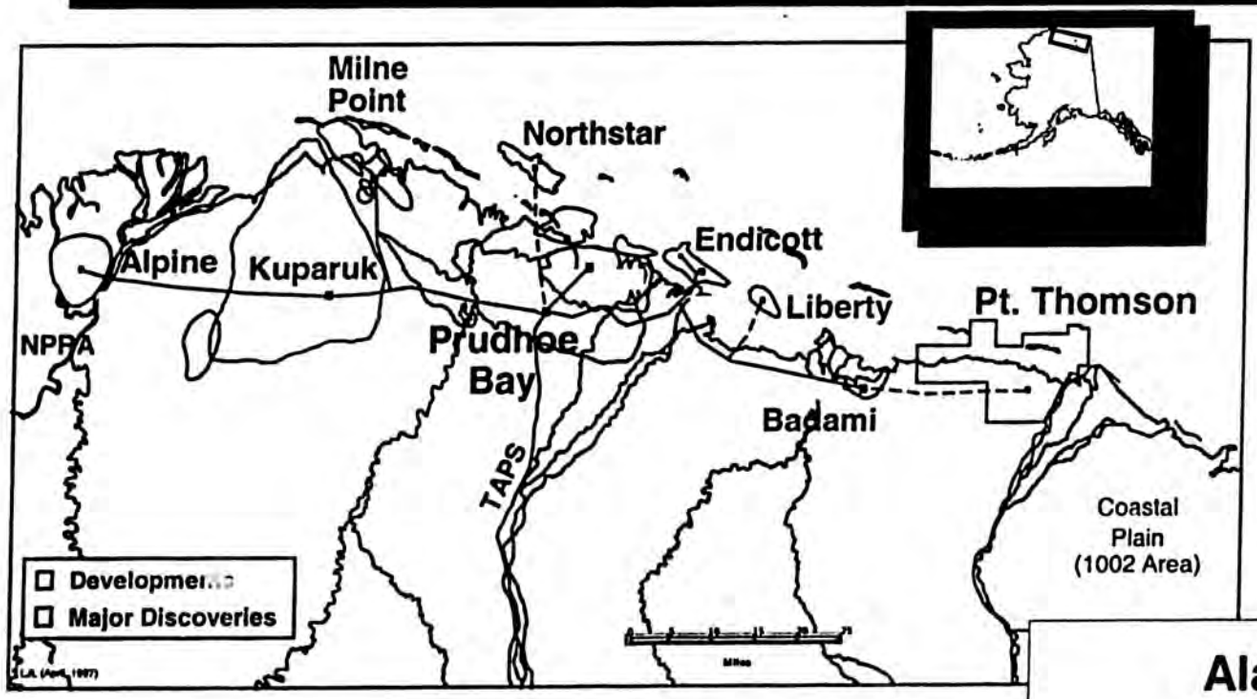
Joint Team Objectives

- Create an economic project (competitive cost of supply)
- Develop sufficient technical information to support FERC/NEB applications as soon as possible (target - year end 2001)
- Prepare for next phase of activity

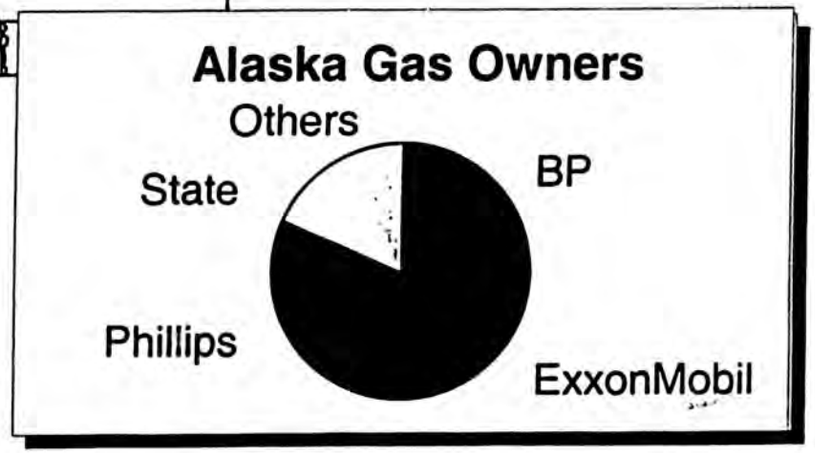
Safe and Environmentally Responsible

North American Natural Gas Pipeline Group

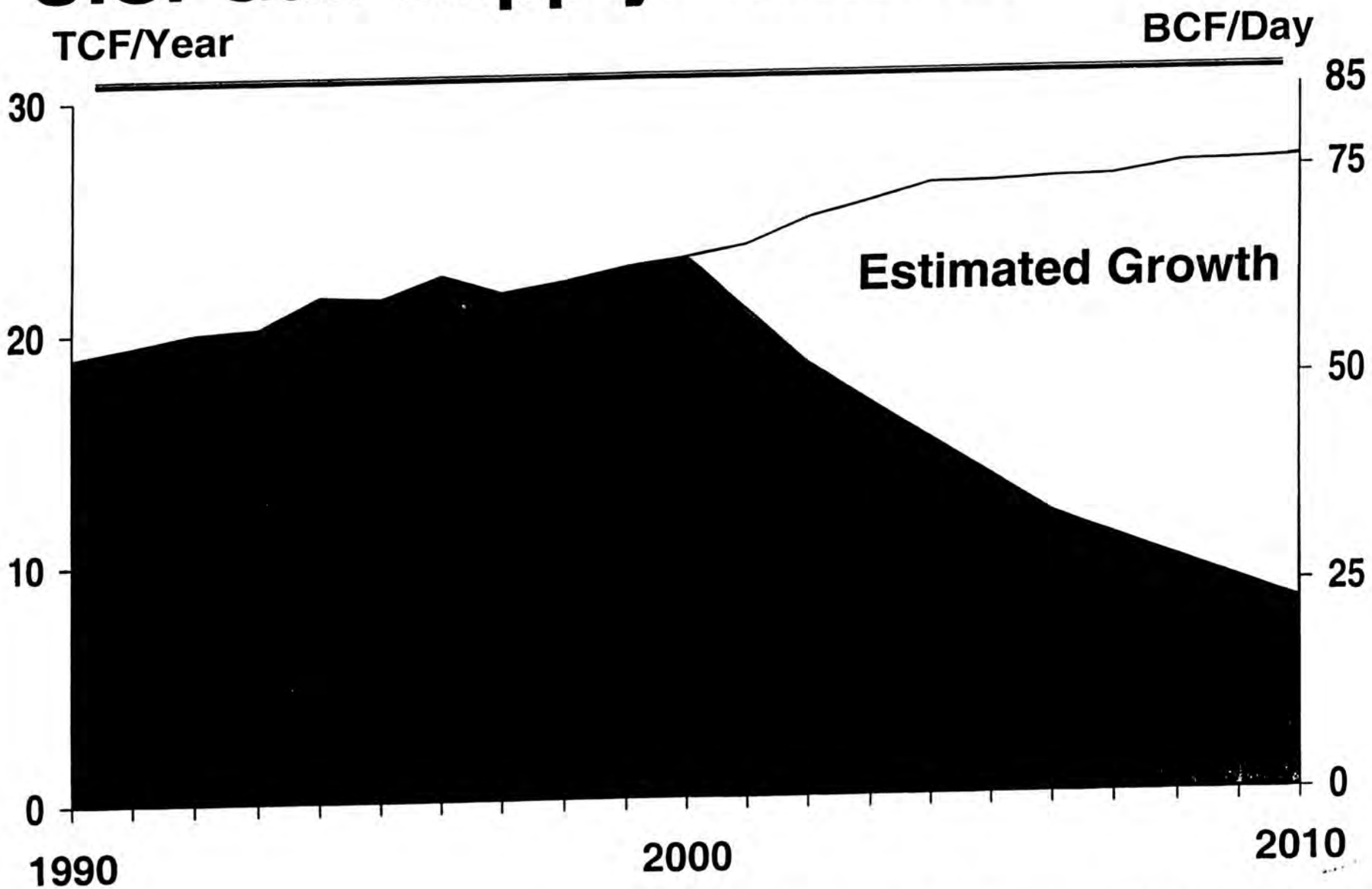
Alaska Gas Resources & Major Producers



- North Slope known resource ~ 35 Tcf
- Prudhoe Bay – 8 Bcf/d of production currently
- Reinjected into reservoir
- Ultimate resource estimates ~100 Tcf

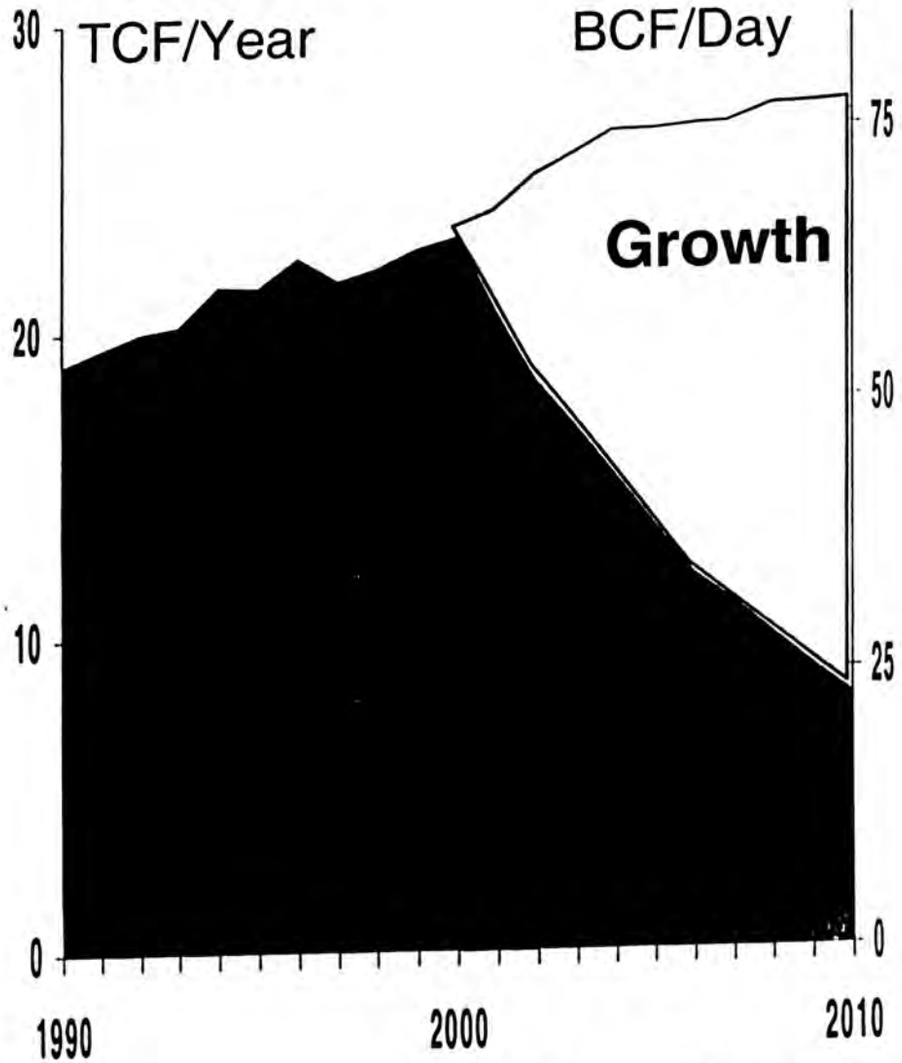


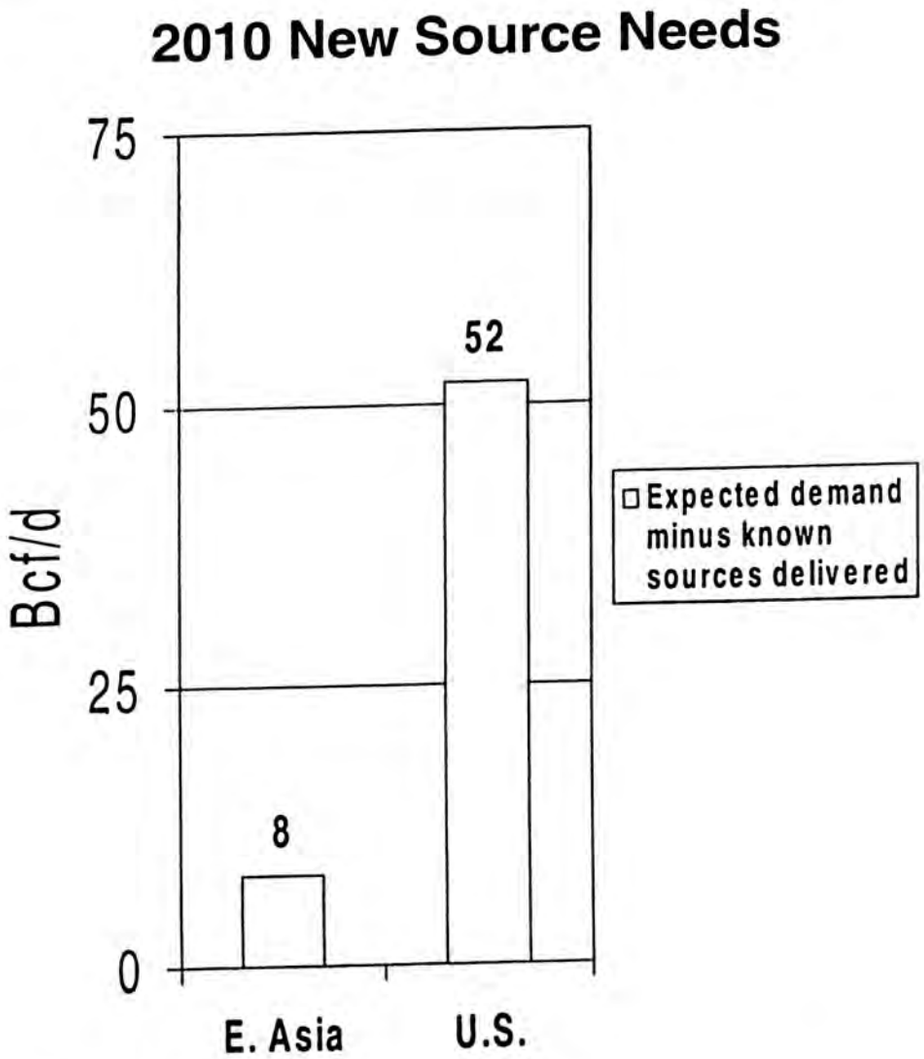
U.S. Gas Supply/Demand



Source: National Petroleum Council, December 1999

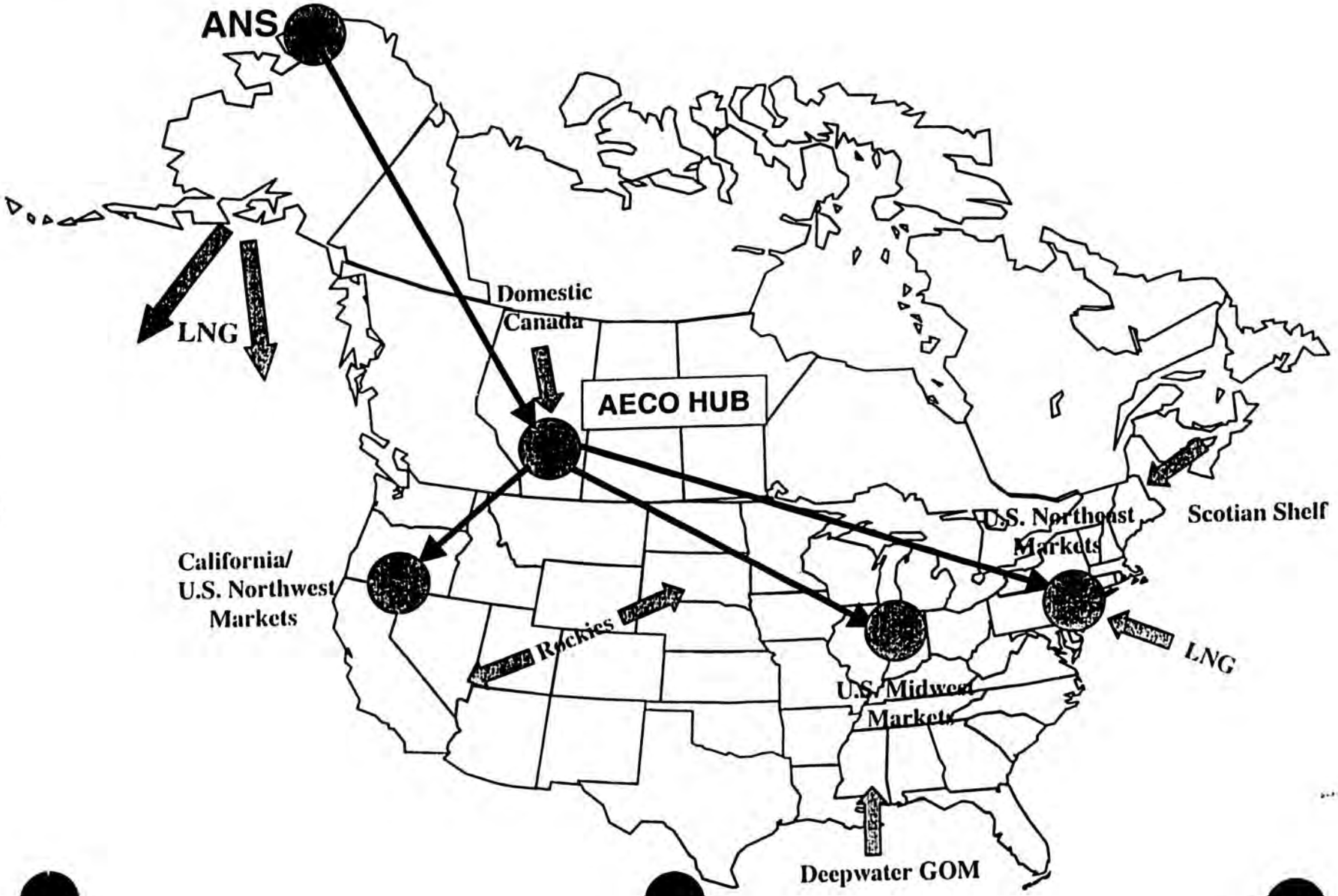
Supply/Demand - Asia Comparison



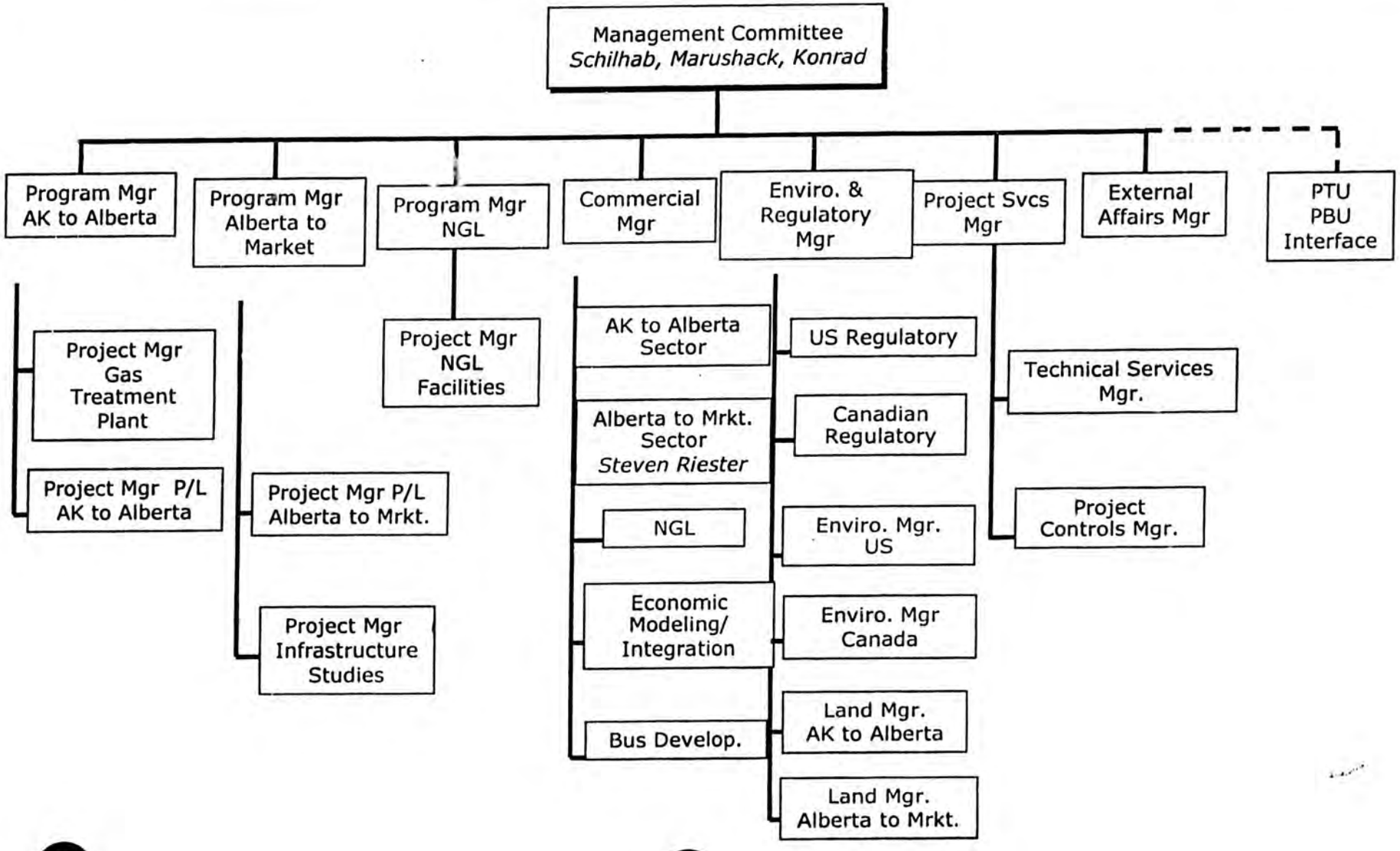


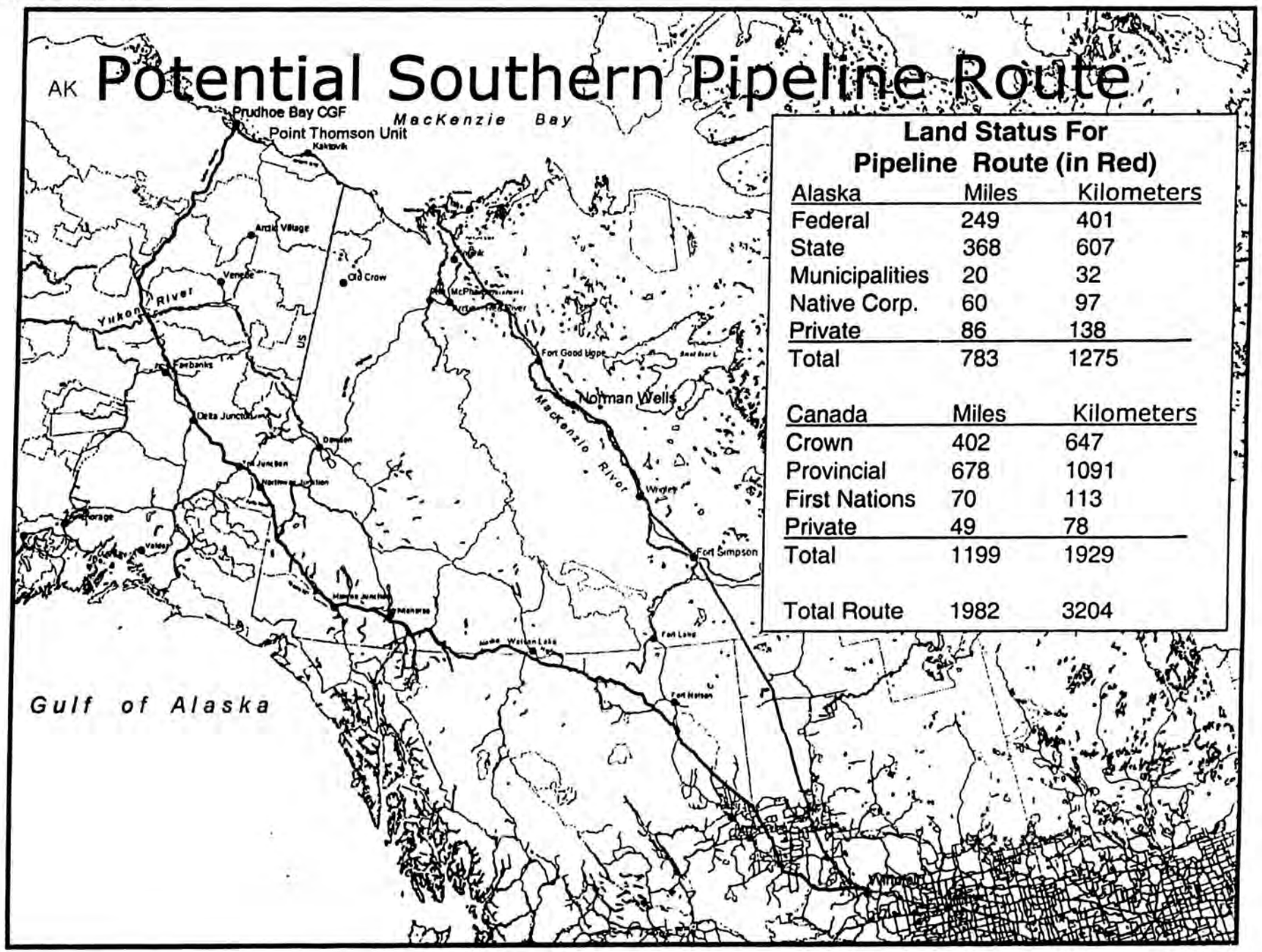
Source: NPC, December 1999 & Tokyo Gas, 2001

North American Gas Supplies/Markets



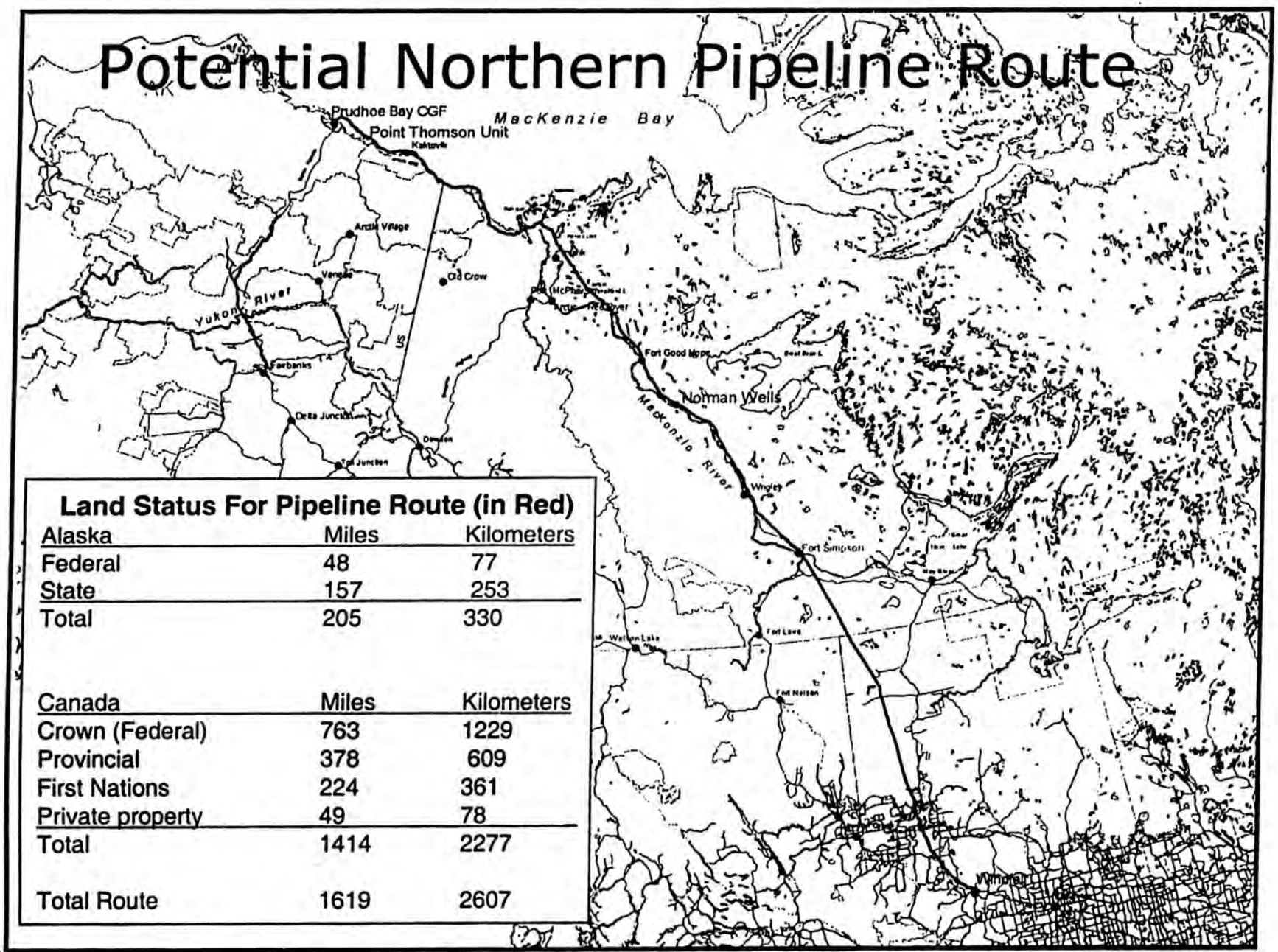
Joint Team Organizational Chart




AK
Potential Southern Pipeline Route
Prudhoe Bay CGF
Point Thomson Unit
MacKenzie Bay
Kaktovik
Arctic Village
Old Crow
Venetie
Yukon River
Fairbanks
Delta Junction
Dawson
Fort Junction
Norman Wells
MacKenzie River
Fort Good Hope
Fort Simpson
Fort Liard
Fort Nelson
Gulf of Alaska
Land Status For
Pipeline Route (in Red)
Alaska | Miles | Kilometers
Federal | 249 | 401
State | 368 | 607
Municipalities | 20 | 32
Native Corp. | 60 | 97
Private | 86 | 138
Total | 783 | 1275
Canada | Miles | Kilometers
Crown | 402 | 647
Provincial | 678 | 1091
First Nations | 70 | 113
Private | 49 | 78
Total | 1199 | 1929
Total Route | 1982 | 3204

North American Natural Gas Pipeline Group

Potential Northern Pipeline Route



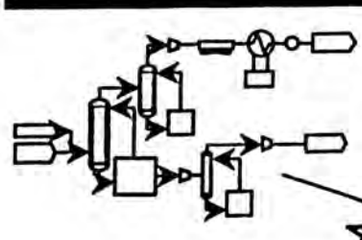
Land Status For Pipeline Route (in Red)

Alaska	Miles	Kilometers
Federal	48	77
State	157	253
Total	205	330

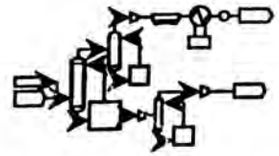
Canada	Miles	Kilometers
Crown (Federal)	763	1229
Provincial	378	609
First Nations	224	361
Private property	49	78
Total	1414	2277
Total Route	1619	2607

North American Natural Gas Pipeline Group

Major Scopes of Work (RFPs)



Gas Treatment Facility (Prudhoe Bay) :
Removal of Acid Gases - CO_2, H_2S
Compress / Chill gas to P/L entry conditions



NGL Extraction Facility:
Removal of C_2+

Environmental / Regulatory – Canada
Field studies

Alaska to Alberta Pipeline System (A-B) :
- Buried, High Pressure, Chilled Pipeline
- Intermediate Compression
- Block Valve Stations
- Intermediate Pigging Facilities



Land – Canada (2)

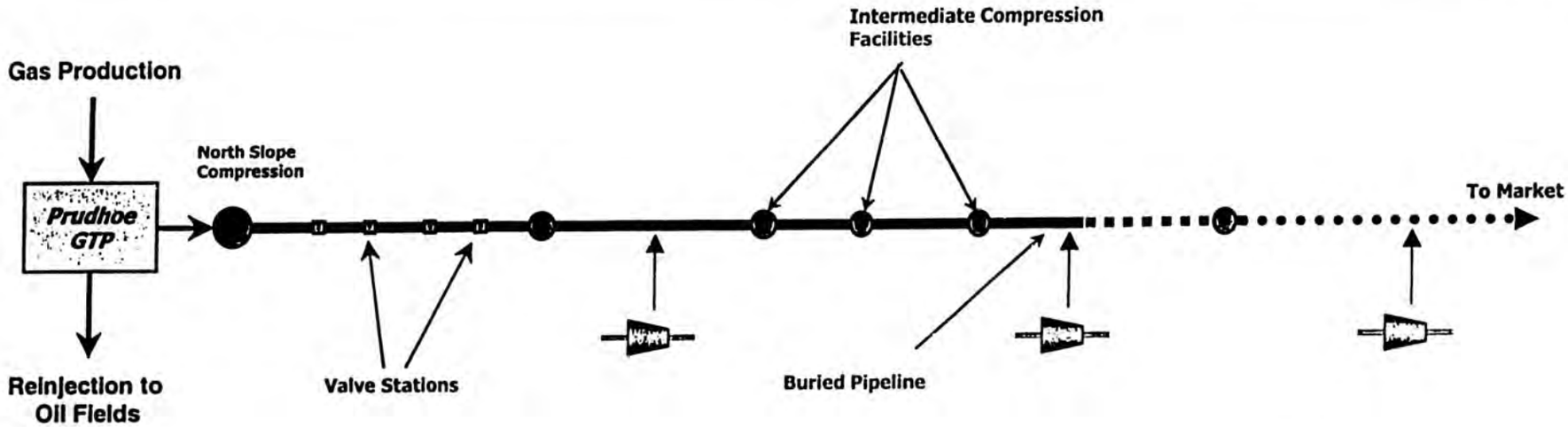
Land – US Lower 48
US Alaskan

Alberta to Market Pipeline System (B-C) :
New-Build and/or Expansion

Environmental / Regulatory – US
Field studies

North American Natural Gas Pipeline Group

Conceptual Pipeline System Components



- Pipeline system is comprised of four main facilities:
  - Buried pipeline (~48", ~2500psi, high strength steel)
  - Intermediate compression facilities
  - Block valve stations
  - Intermediate pigging facilities

North American Natural Gas Pipeline Group

Applying 21st Century Technology

Attributes

- Advanced materials & design
- High Pressure operation
- Buried line with thermal control
- Fewer, more powerful compressor stations
- Advanced construction (trenching, welding, river crossings)
- Advanced communication & control systems
- Advanced monitoring and maintenance systems

Benefits

- Lower fuel consumption
- Reduced emissions
- Smaller footprint
- Reduced environmental impact
- Expansion capacity
- Lower cost of supply
- High reliability

North American Natural Gas Pipeline Group

Conceptual Pipeline Construction Plan

- Multiple construction spreads working over 3 year period.
- Onshore
  - Principally winter construction – especially in permafrost.
  - Pipeline buried except for few specific crossings.
  - Grade-only construction where soils allow.
  - Primarily snow pads where soil/vegetation require protection.
  - Gravel construction pads required where protection is required and slopes are excessive for snow pads.
- Offshore
  - Summer construction from lay vessels.
  - Primarily offshore supply from existing infrastructure.

North American Natural Gas Pipeline Group

The "Seven Lenses" of Evaluation

- Economics
- Revenues
- Jobs
- Gas Access
- Safety
- Timing
- Environment



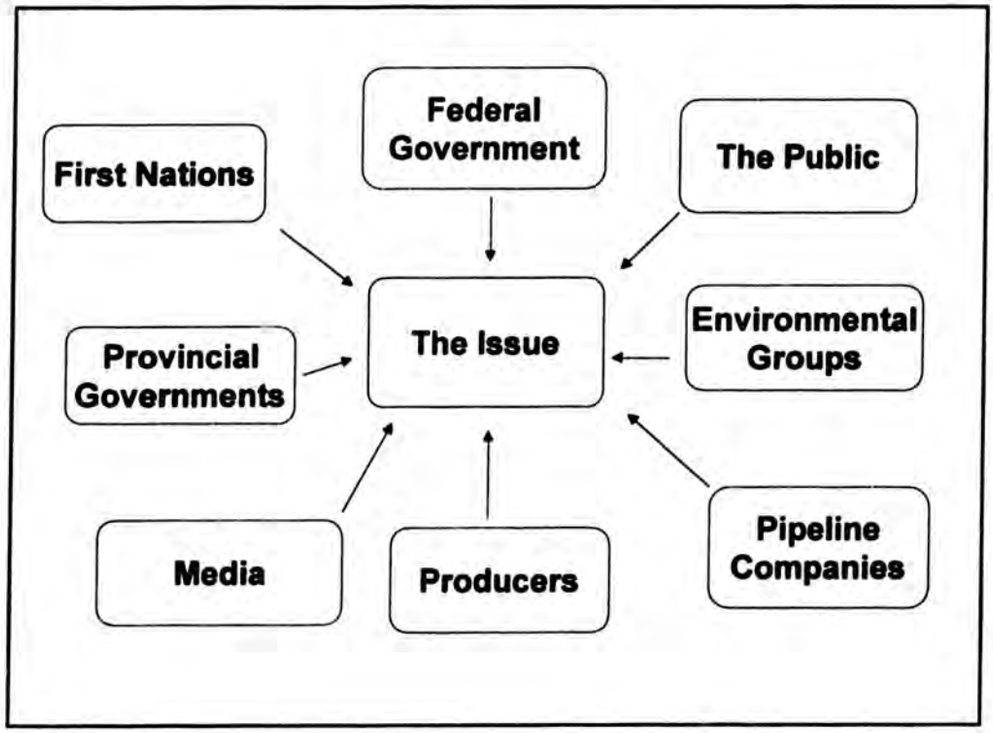


Canada and the Northern Pipeline

Presentation to the Governor's Alaska Highway Natural Gas Policy Council

March 23, 2001





Federal Government Position

- The pipeline route must be picked by the producers. The Canadian Government will not endorse one route over another.
- The government's role is to ensure a smooth regulatory regime that recognizes legitimate business imperatives while allowing for adequate public input.

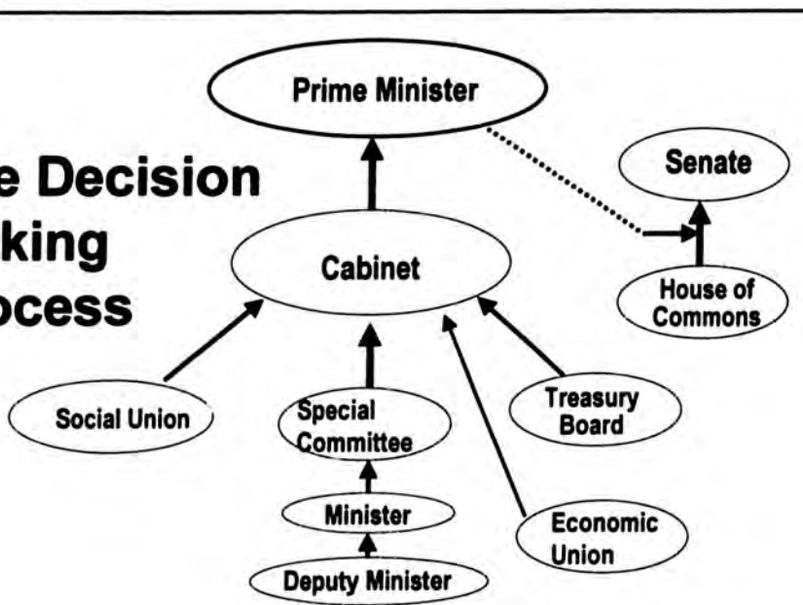
Federal Government Position

- Projects that bring maximum benefit to Canadians will be supported over those that do not.
- The Federal Government wants to co-operate on energy issues and wants to be part of any continent-wide energy agreement.

The Federal Players

- Indian Affairs & Northern Development
- Environment
- Foreign Affairs
- International Trade
- Fisheries and Oceans
- Industry
- Privy Council
- Human Resources Development
- Finance
- Treasury Board
- Northern Pipeline Agency
- Canadian Environmental Assessment Agency

The Decision Making Process



The Major Players

Prime Minister Jean Chrétien



- First elected in 1963
- Has held every major cabinet post including Indian Affairs and Northern Development, Energy Mines and Resources and External Affairs
- Great affinity for the North

Hon. Bob Nault, Indian Affairs and Northern Development



- First elected in 1988
- Appointed to Cabinet August 1999
- DIAND is his first portfolio
- See this project as the biggest economic development project for Canada this decade

Hon. Ralph Goodale, Natural Resources Canada



- Appointed Minister of Natural Resources in 1997.
- Has regional political responsibility for the North
- Chairs the powerful Economic Union Committee of Cabinet

Hon. David Anderson, Environment



- Elected 1968 - 72 and re-elected in 1993.
- A pragmatic environmentalist
- Best known to Alaskans as Canada's Minister of Fisheries and Oceans 1997 - 99

Premier Pat Duncan, Yukon



- First elected in 1996
- Became leader of the Yukon Liberal Party in 1998
- Led Party to victory in 2000 and became Premier
- Main goal is to make the Yukon more autonomous

Premier Stephen Kakfwi, Northwest Territories



- First elected in 1987
- Has held every major cabinet portfolio
- former president of the Dene Nation
- Active in opposition to the original pipeline agreement

Next Steps

- Amendments to the Canadian Environmental Assessment Act
- Single Window Regulatory Access in the North
- Devolution of Powers to the Yukon and Northwest Territories
- Continuing Land Claims Negotiations

Thank You

Questions ?

Alaska Highway Natural Gas Policy Council
Workshop II Agenda

Thursday, April 5, 2001
Anchorage Sheraton Hotel – 10:00 a.m. to 5:30 p.m.

I. Call to order/opening remarks, 10:00–10:30

II. Presentation from Alaska Gasline Port Authority, 10:30-11:15

III. Presentation from Foothills Pipe Lines Ltd., 11:15-12:00

IV. Lunch break, 12:00 –12:30

V. Presentation from LNG Sponsor Group, 12:30-1:15

VI. Presentation from Yukon Pacific Corporation, 1:15-2:00

VII. Council Business, 2:00-2:30

VIII. Subcommittee Session I, 2:45-4:00
A. State's Royalty Share – Bill Corbus, chair
B. Access to the gas/In-state gas consumption– Ken Thompson, chair
C. Linking other future opportunities/markets – Carl Marrs, chair

IX. Subcommittee Session II, 4:15-5:30
A. Alaska Hire/Buy/Build – Mike Navarre, chair
B. Federal/International Action – Charlie Cole, chair
C. Environmental Considerations – Peg Tileston, chair

Alaska Highway Gas Policy Council
Meeting Summary
April 5, 2001, Anchorage, Alaska

Co-chair Jim Sampson called the meeting to order.

Gov. Knowles briefed the council on recent developments in the national energy situation. The outlook is for continued shortages of electricity in parts of the country, and high prices for natural gas. There have been no significant changes in the situation.

The governor attended an energy conference in Houston also attended by Canadian leaders, which was heavily attended due to high interest in the energy situation. Knowles' message to the conference was that Arctic gas - Alaskan and Canadian - can help meet the nation's energy needs. Alaska is not in competition with Canada, because new gas from all sources - the Arctic, western Canada, East Coast Canada, Gulf of Mexico, and LNG imports - will be needed to meet the expected demand.

Knowles also told the council that Senate President Rick Halford and House Speaker Brian Porter have agreed to become members of the council. Pressing legislative businesses prevented their attendance April 5, but they will be more involved after the Legislature's adjournment in early May.

April 5 presentations to the Council:

Alaska Gasline Port Authority:

Dave Cobb, former Valdez Mayor and member of the port authority board, gave the presentation.

The port authority was created under Alaska statutes allowing separate port authorities to be formed by municipal governments. It was created when it was approved by voters in the City of Valdez, Fairbanks North Star Borough and North Slope Borough in October, 1999.

Cobb said that three guiding principles for the authority include creation of jobs, providing gas to Alaskan communities and helping stabilize the state economy by helping commercialize stranded North Slope gas. The approach, using tax-exempt public debt financing for a portion of the project, would lower costs and dramatically increase the economic viability of a large gas project, and maximize benefits to both Alaska and the

producer companies.

The three municipalities forming the port authority each contributed $100,000 to its startup costs, Cobb said. Yukon Pacific Corp. made a $250,000 contribution, along with a $75,000 contribution by Bechtel Corp, he said. The authority has a Memorandum of Understanding with Bechtel, under which the company did a "ground up" (i.e. original, not built on previous work) construction cost estimate, an effort that involved about 55,000 manhours of work. Bechtel has about $5 million to $6 million invested in this effort, which involves the use of state-of-the-art pipeline technology, Cobb said. The international financial consultants Taylor-Dejoung developed the economic model based on Bechtel's cost estimate.

Two other accomplishments of the authority include obtaining a ruling from the Internal Revenue Service that the authority is a public corporation exempt from federal income tax, and an assurance from the Federal Energy Regulatory Commission that a gas project built by the authority would not be subject to FERC review, Cobb said.

The authority contemplates financing 100 percent of the project and distributing net revenues on a formula providing for 60 percent of revenues paid to the state of Alaska, 30 percent to all Alaska municipalities and 10 percent retained by the authority and the three municipalities that formed it. The distribution to municipalities is intended to replace state revenue-sharing, which has declined substantially in recent years. The minimum payment to any community, no matter how small, is $50,000 per year, Cobb said.

By taking advantage of exemptions from many federal, state and local taxes, a gas project built by the authority would result in $2 billion to $3 billion in revenues to gas producers over what a privately-built project would produce, and an additional $1 billion to the state of Alaska.

Valdez has a history of promoting similar pubic/private partnerships, Cobb said. During construction of the trans-Alaska oil pipeline in the 1970s, the City of Valdez issued revenue bonds to financed parts of the Valdez Marine Terminal. The city is the owner of these facilities, Cobb said, and both Valdez and the pipeline owner companies have realized substantial benefits from the arrangement.

Questions from the Council:

A question was asked about assumptions of gas volume and throughput.

Cobb replied that the authority believes in the "Y" concept, with one pipeline built through Interior Alaska to the Lower 48 and a second pipeline branching off to an LNG plant on the southern Alaska coast. The project envisioned by the authority would carry 6 billion cubic feet of gas daily from the North Slope to the "Y" junction in the Interior. Three billion cubic feet of gas daily would then be shipped on to the Lower 48, and three billion cubic feet of gas daily shipped to the LNG plant through the second pipeline.

A council member asked about guarantees for the bonds.

Cobb replied that the authority would guarantee debt issued for the project. If the bond market doesn't believe the project is feasible, the bonds won't be purchased, he said.

He stressed that the authority would own the project but would contract for construction and operation. Also, while the most financially advantageous project involves the authority actually purchasing gas from the producers and selling it, the producers could also contract to ship their own gas through a gas pipeline owned by the authority. The authority could also own part of a project. For example, if the producer want to retain ownership of a pipeline to the Lower 48, the authority could build the spur pipeline to southern Alaska. "We believe the port authority can fit in anywhere. There are advantages without full-scale involvement," Cobb said.

A council member asked for more information about the allocation of revenues, and a comparison of how the state and its communities benefit under the status quo, retaining their own full taxing authority (such as state corporate income tax), and the tax-exempt, revenue-distribution concept proposed by the authority.

Cobb replied that this analysis has been done and that he would provide it the council.

A council member asked why the state couldn't do what the authority proposes to do, with similar advantages.

Cobb replied that financial consultants had advised that if the state were the financing entity, bond buyers would very likely ask for backstop guarantees from the Alaska Permanent Fund. Because the port authority is an independent public corporation, with, under state law, no guarantees

required from either the municipalities involved or state government, a bond buyer would have to look only to the project, because the authority has no funds to guarantee bonds.

An observation by a council member was that guarantees from the producers would likely be involved, in the form of long-term contracts to ship gas.

Another council member observed that until very recently, producers were not involved in pipeline ownership in the Lower 48. The take-or-pay contracts they signed served as guarantees to independent third parties building and operating the pipelines. This has changed in the last 20 years. Producers have become involved in riskier domestic pipeline projects built into new areas to control costs. Overseas, a model of part government and part private ownership has involved, with governments desiring an involvement so as to be able to participate in the setting of tariffs. Producers become involved for the same reasons, and to control costs.

Another motive for producer involvement is to enjoy the financial benefits of an equity position in a pipeline, it was explained. Rate of return on a pipeline investment is typically lower than from a producing property, but it is constant, without the ups and down of production revenues (due to price volatility) and is a good source of steady cash-flow.

Foothills Pipe Lines, Ltd.

John Ellwood, vice president engineering and operations, gave the presentation.

Foothills is a joint-venture company formed by TransCanada Pipelines Limited and West Coast Energy, two of Canada's largest pipeline companies, to participate in an Alaska natural gas pipeline project when it was first proposed in the late 1970s.

Ellwood sketched the history of the company's involvement in the Alaska gas pipeline project. Foothills was originally formed to build the Canadian portions of the Alaska Natural Gas Transmission System (ANGTS.)

Meanwhile, two "pre-built" portions of the system, from western Canada to the U.S. midwest and Pacific Northwest, were built by Foothills and are in operation today. As for the Alaska portion, as members of the ANGTS consortium withdrew from the project Foothills purchased their interest. "We saw real value in the Alaska Natural Gas Act, its Canadian counterpart and the U.S.-Canada Treaty because they will get a project done quickly.

That is why we devoted extensive efforts to keep the permits alive."

Today Foothills is the operator of the ANGTS project, which has permits and rights-of-way for a gas pipeline along the Alaska Highway through Alaska and Canada. Foothills has kept all of the permits for the system in good standing, Ellwood said. The permits will have to be updated to reflect different volumes of gas and the new technology being incorporated, but the updating can be done without difficulty, he said.

The pre-built parts of the system were a gamble at the time, Ellwood said. They were built because there was no assurance that the northern part of the project would be completed (it wasn't). The pipelines were built oversized for the gas then available for shipment, and the Canadian government sought an assurance from the U.S. government that the Alaskan part would eventually be built. The assurance was given.

However, gas production from western Canada has expanded considerably and today the pre-built sections are not only full, but have been expanded five times, each expansion incorporating the latest in new technology, Ellwood said. The pre-built pipelines now carry 3 billion cubic feet per day of gas, roughly 5 percent of U.S. gas consumption.

Today the legal structure of the U.S. presidential decision, laws passed by both the U.S. Congress and Canadian Parliament and the U.S.-Canada treaty remain in full force, Ellwood said. A 1977 conditional certificate issued by the Federal Energy Regulatory Commission also remains in effect, he said, as does a right-of-way across federal lands in Alaska and a conditional state right-of-way.

These do not give Foothills a perpetual franchise but they do give the ANGTS project a priority over any competing applications, he said.

Some are suggesting that Foothills must use only the original design specified in the existing permits, Ellwood said. "We have researched this carefully, and it is not the case. Section 9 of the (federal) Alaska Natural Gas Act gives FERC the authority to amend our certificate, as long as we don't change our basic route or the nature of our project," he said.

Another change since the 1980s was that the Office of the Federal Inspector for the ANGTS project, originally within the Department of the Interior, was moved to the Department of Energy. Ellwood said the Secretary of Energy has given assurances that the functions of the Federal Inspector would be carried out by his office should the project be revived.

A key advantage of the existing laws is that they provide for limited judicial review. "That is a very valuable asset," Ellwood said.

The company has a "pending" right-of-way application with the state of Alaska to cross state-owned lands. Foothills is now in discussion with the state on renewing work on that application.

On the Canada side, the company has a Certificate of Public Convenience and Necessity issued by Parliament, which means only that body can revoke the certificate. Also, a right-of-way has been established across Yukon Territory which is not subject to land claims by First Nation groups. All 14 First Nation groups have signed an agreement recognizing the right-of-way, Ellwood said.

What the company does not yet have is a commercial agreement with the North Slope producers, he said, and Foothills is now devoting its energies to achieving that. "We anticipate the producers will want some part in ownership and control," Ellwood said. That isn't a problem. "We want to be part of the solution, not a problem," for the producers, he said.

The key message that Foothills would like to leave with the council, Ellwood said, is that the expedited regulatory review system established under the existing laws and treaty constitute a valuable asset for Alaska and the producers, as well as for Foothills because it would allow a gas pipeline project to get through red tape very quickly.

A council member asked if Foothills, as a Canadian company, will seek U.S. companies as partners.

Ellwood answered that his company is open to new partners but that the first priority is to get a commercial agreement with the producers.

A question from the council asked status of a lateral pipeline to the Mackenzie Delta provided in the 1980s laws and treaty agreements.

Ellwood responded that the existing laws and treaty do provide for a spur pipeline along the Dempster Highway that would join the ANGTS pipeline near Whitehorse, Y.T. That pipeline was planned when there was a moratorium on pipelines along the Mackenzie River valley because o unsettled Native land claims. Those claims are now being resolved, and communities along the Mackenzie now support a pipeline. Oil and gas companies with interests in the Mackenzie delta are now considering a stand-alone pipeline south along

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2965 SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPLINES, 2001-02

the Mackenzie, so the Dempster Highway route is no longer needed, he said.

A council member asked why the Alaska Highway "southern" route has advantages over the "northern" offshore route, if that route is shorter.

Ellwood responded that Foothills conduct a 50,000 man/hour study of the northern route and concluded that it would wind up costing about the same as the southern, highway route because of potential problems with ice scour and trenching in the offshore segments, and problems of where to locate compressor stations if an onshore site in unavailable in wildlife refuges in northeastern Alaska (ANWR) and Yukon Territory. The southern route, although longer, has less risk. Also, availability of existing road infrastructure is a big asset.

Ellwood added that an additional problem facing a northern route is the commercial problem of sizing the pipeline to carry an unknown amount of gas from the Mackenzie delta that is unproven (undrilled) at this point. In contrast the North Slope gas is a proven, confirmed resource. The problem is financing a northern route pipeline with enough capacity to carry both Alaskan and Mackenzie gas without the Mackenzie reserves defined to the point where contracts for gas shipment can support the additional investment.

A council member asked about available capacity in pipelines from Canada to the U.S. that could connect with an Alaska pipeline in western Canada.

Ellwood responded that the existing pipeline grid in Canada has about 1 billion to 1.5 billion cubic/feet per day unused capacity. Even if that capacity is not available by the time an Alaska pipeline is built (production from Canada is expected to increase by that time) the pipeline grid can be expanded, as it has before, or a new pipeline can be built.

Alaska North Slope LNG Project

Steve Alleman, project manager, made the presentation.

Alleman reviewed his group's progress to date in its work on an LNG export project. Phase one, completed last fall, involved $12 million expended in conceptual engineering, commercial and market feasibility work.

This was successful in that a scaled down project was defined that would produce a volume of LNG (7 million tons/LNG annually) that might better fit into what the sponsor group feels is the available market in the Pacific.

The project can then be expanded as the market develops.

However, even a scaled-down project was not deemed to be cost competitive, Alleman told the council. The group's current key focus, in a $3 million phase two effort, is to find potential cost savings through synergy with the Lower 48 pipeline project being planned by the North Slope producers. This would involve the "Y' concept, or a pipeline spur connecting in Interior Alaska that would carry gas to a southern Alaska LNG plant. This would shorten the distance of new "stand alone" pipeline. The lower capital cost might improve the project's economics but whether it would be enough is still uncertain.

Alleman told the council that his group expects to conclude internal studies on an environmental assessment of the Cook Inlet route by the end of April, and to have cost estimates for a project that links with the Lower 48 pipeline as early as mid-June or July.

A council member asked about any benefits of public financing or public ownership.

Alleman said his group's analysis so far is that no compelling advantage is presented in a "public/private partnership" with an entity like the Alaska Gasline Port Authority (meaning a project partly owned by both industry and the authority). He added, however, that full public ownership of a project that can fully realize federal tax advantages may be different. Further discussions with the port authority are planned.

To illustrate the challenges the LNG project faces, Alleman showed a slide to the council that compared estimated capital costs of other proposed LNG projects, including proposed expansions and new "greenfield" (entirely new) projects, like Alaska, that are competing for the expected new demand in Asia. Figures in the chart are based on published information, he said.

The chart shows the average capital cost among the competing projects, per million tons of LNG delivered yearly, range between $225 million to $250 million per million tons of annual LNG delivery. The estimated cost of the Alaska project, with a stand-alone pipeline (i.e. without the link to the Lower 48 pipeline) ranges between $610 million to $790 million per million tons delivered. The 800-mile pipeline (in the case of a stand-alone pipeline) is about $300 million per million tons per year, or 40 percent to 50 percent of the project total unit cost. The pipeline is a huge challenge for the project when compared with its competitors, which are at tidewater, Alleman told the council.

(Editor's note: Three of the LNG sponsor group's four members are involved in Lower 48 pipeline studies: BP, Phillips and Foothills.)

A council member asked why the existing Phillips LNG plant at Nikiski couldn't be expanded, in a case where a pipeline went to Cook Inlet.

Alleman replied the group continues to look at that, and has not ruled out exploring possible synergies there.

A council member asked about the economics of ocean shipping of LNG. With Phillips looking at importing LNG from Australia to the U.S. West Coast, wouldn't Alaska, with a shorter shipping distance, be as or more competitive?

Alleman replied that his group had compared published estimates on "total cost of service" (including shipping) from Australia to California, and penalized the Australian service with the need for additional ships because of the longer distance. The Alaska project, in shipping LNG to California, still wasn't as competitive, he said, primarily because of the 800-mile Arctic pipeline that an Alaska project must overcome.

A council member observed that some of the existing LNG projects in southeast Asia can be more competitive than a new Alaska project, even with a longer shipping distance, because the LNG tankers are already built and in service. He asked for more information on the total cost of service of supplying LNG from Australia compared with estimates for an Alaska project, which is one quarter of the distance.

Alleman said he would get the information to the council on shipping distances.

Yukon Pacific Corp.

The presentation was made by Jeff Lowenfels, president and CEO of Yukon Pacific.

Lowenfels said there are three "myths" about an LNG project, that there is "no market," that LNG is not an option, and that the overland (Lower 48) project is the only option. Alaska gas does face challenges because of its remote location and competition from other LNG projects, so any project from Alaska must be big to achieve economies of scale.

Despite all the work on gas over the years, the producers were not in a position to sell gas until June, 2000, when the realignment of ownership in the Prudhoe Bay field changed conflicting priorities among the field owners, mainly three major producing companies.

Yukon Pacific has done extensive work on permits over the years and has secured the major "deal-killer" permits, Lowenfels said. In comparison, it will not be easy to permit the Alaska Highway route with the existing requirements of U.S. and Canadian laws on a highway pipeline, he said.

As for market demand, several studies, including independent U.S. groups like Standard and Poors, feel Asian demand for LNG will grow sharply. Estimates by private industry within the three Asian nations that are most likely markets for Alaska gas, Japan, Korea and Taiwan, show strong future demand. Government estimates are lower because they assume more power will be supplied by nuclear plants, an assumption private industry discounts, Lowenfels said. India and probably China are probably not markets for Alaska because those countries can be supplied more economically by producers in Southeast Asia and the Middle East, but growing demand for LNG in both countries will take supply off the market, indirectly helping Alaska.

Lowenfels showed a chart showing results of two studies by engineering groups, one by Willbros Engineering and Micheal Baker Jr., and a second by Kellogg Brown & Root and Air Products and Chemicals, Inc. The estimates showed a "startup" project delivering 9.2 million tons/year of LNG could be built for $6 billion (2000 dollars), expanded to 13.8 million tons/year with an additional investment of $1.1 billion, and expanded again to 18.4 million tons/year with an additional $1.2 billion investment.

The total "cost of service" to Japan, including shipping, at a "low" case of $1.99 per million British Thermal Units (Btu) delivered to a "high" case of $2.91 per million Btu delivered. This appears attractive in the context of estimates by Tokyo Gas that it will contract LNG for $3.88 per million Btu between 2005 and 2010. "Our numbers work," said Lowenfels.

In discussion following the presentation, Lowenfels said YPC was shocked to discover that the assumptions used in the Purvin & Gertz (a consulting firm relied on by industry and the state) study for LNG relied on generic "off the shelf" data rather than estimates compiled by YPC itself. The effect is to understate the benefits of an LNG project, Lowenfels said. YPC is now discussing the report with Purvin & Gertz, and is hopeful that a more up-to-date "apples to applies" comparison can be made.

Lowenfels urged the council to question why the "highway" is its mandate. Yukon Pacific has been working on an LNG project for many years, but was not consulted, he said. He said he didn't know what information the state administration relied on in making its decision in favor of the highway route, but he suspected it was the Purvin & Gertz study.

A council member observed that he has always favored access to multiple gas markets, since individual markets will always cycle up and down. He asked if the Lower 48 pipeline now being planned helps Yukon Pacific's project. Why doesn't YPC plan a smaller project, sized to fit the market, building off the larger pipeline?

Lowenfels replied that YPC had always built in an assumption of size that would allow a pipeline to the Lower 48 to branch off at Delta. He said his company also favors some form of transparency (clear, predetermined procedures) for gas offtake, if not public ownership.

A council member asked if YPC sees a higher wellhead price for gas from an LNG project, why Phillips (lead company in the industry LNG consortium) doesn't also see that.

Lowenfels replied that individual companies may have other projects with higher rates of return, fewer partners to deal with or complexities in putting a project together, or combinations of all those. There may be other factors affecting Phillips' decision to participate in a project to import LNG from Australia rather than Alaska, such as a possible deadline on a concession in Australia.

A council member replied that it seemed odd that Phillips, with an ownership interest in Alaska gas and a motivation to commercialize the asset, doesn't see a return similiar to than in Australia, which is more distant.

Lowenfels replied that projects compete for funds, and investments go to the project with the highest return and fewest headaches. "I think that's what is going on here," he said.

A council member asked if there wasn't a danger is proceeding on a parallel track with the pipeline to the Lower 48.

Lowenfels replied that he has no confidence the Lower 48 pipeline will really proceed. Even the companies

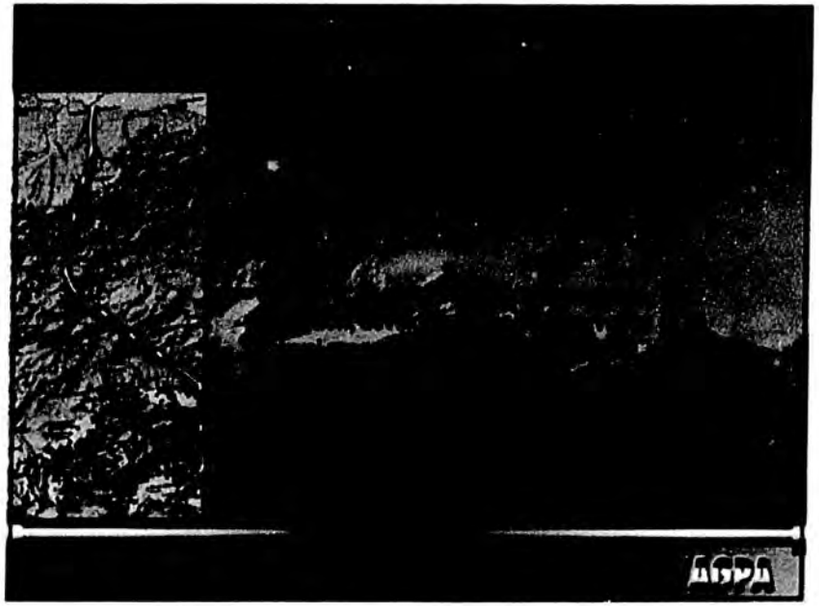
involved say they're not sure they really have a project, he told the council. That is why YPC is continuing to work on its own project. "We hopes it (the Lower 48 pipeline) does go, because we can easily piggyback on it. But we can't stop our work to wait for them," Lowenfels said.

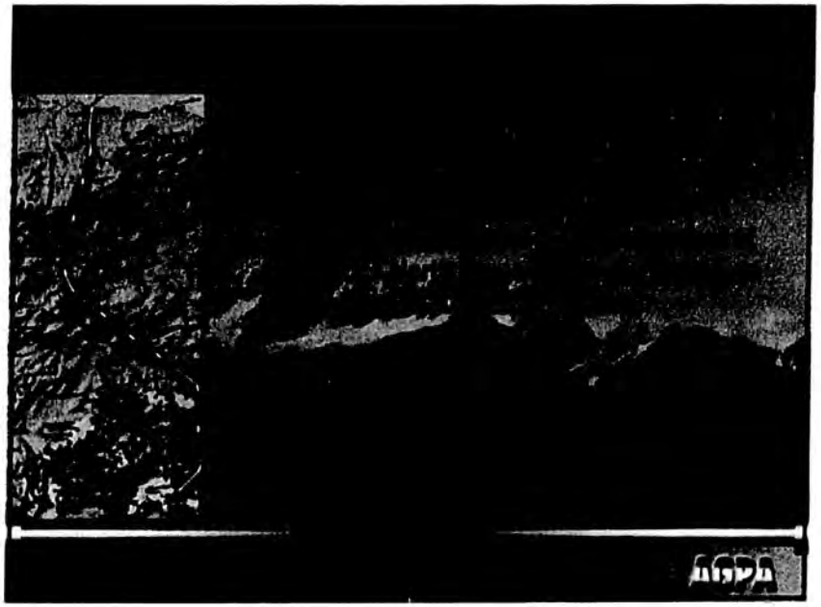
The Lower 48 pipeline, and the governor's decision to support it, has been a setback for Yukon Pacific, however. It sends a message to potential buyers in Asia that Alaska has might not be available. That is why the senior gas manager from Tokyo Gas came to Alaska a few weeks previous, to tell state and community leaders that his company is very interested in North Slope gas.

Lowenfels also observed that discussion of a 6 billion cubic feet/day gas throughput for a project (in the port authority's case) is too high. It would deplete the only current North Slope reserves in production in nine and a half years. Lowenfels said that only current production is available today. There is no assurance any other fields will be opened and hence only the 21 trillion cubic feet left in the Prudhoe Bay Unit is available for any project. YPC's project assumes a lower throughput rate of two billion cubic feet/day, which can be sustained for a much longer time.

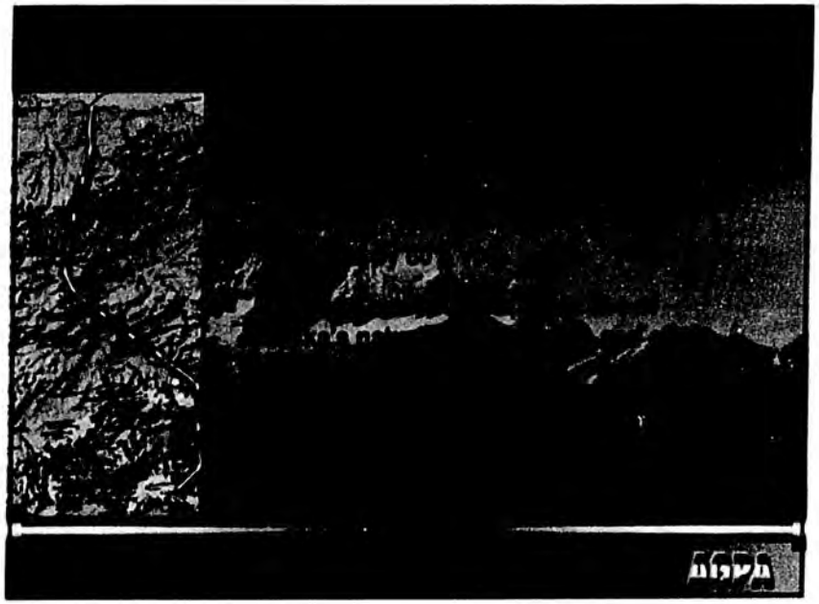
A council member asked Lowenfels' opinion of a gas reserves tax (a state property tax) on undeveloped gas on the North Slope. (The proposal has been made by a state legislator).

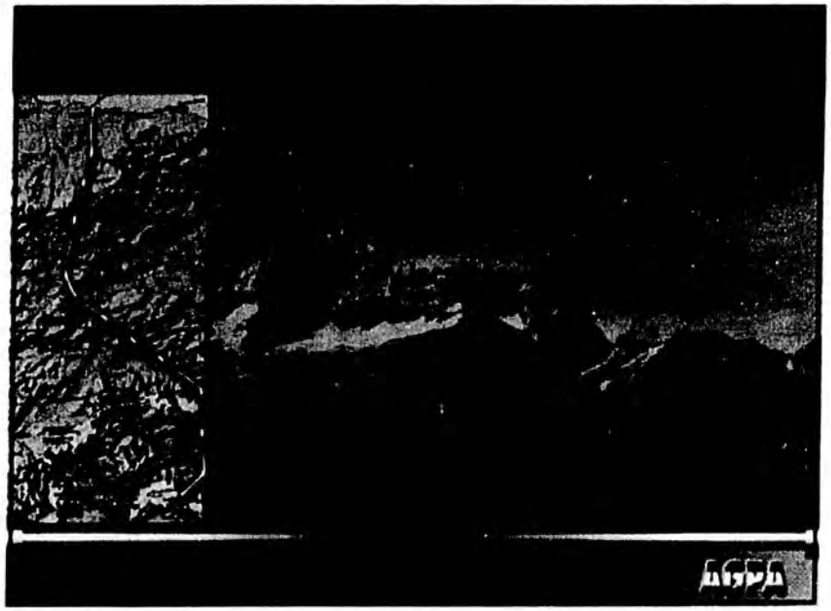
Lowenfels replied that the idea was interesting, and may be appropriate.



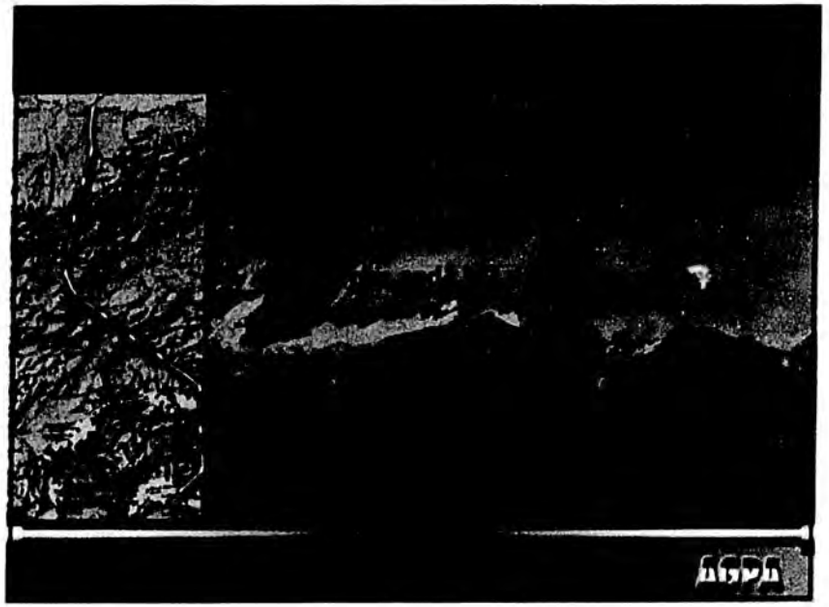


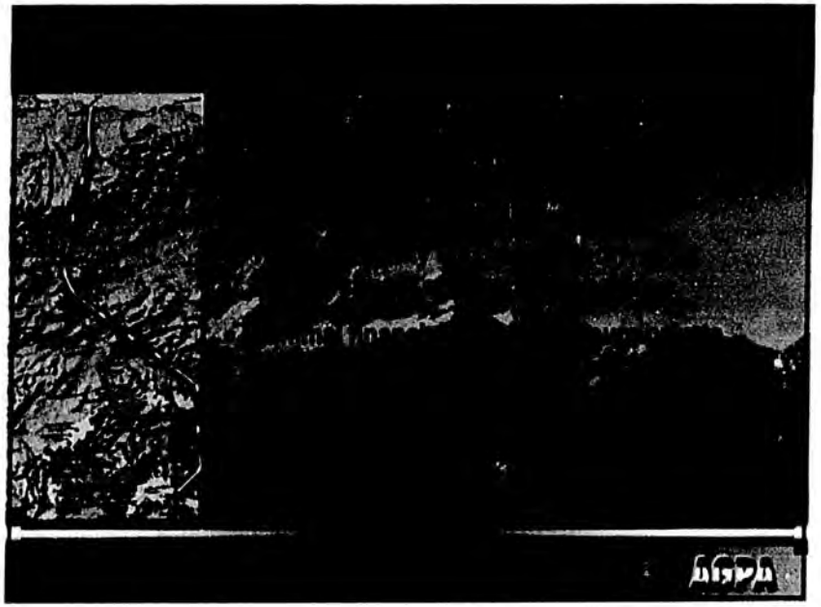




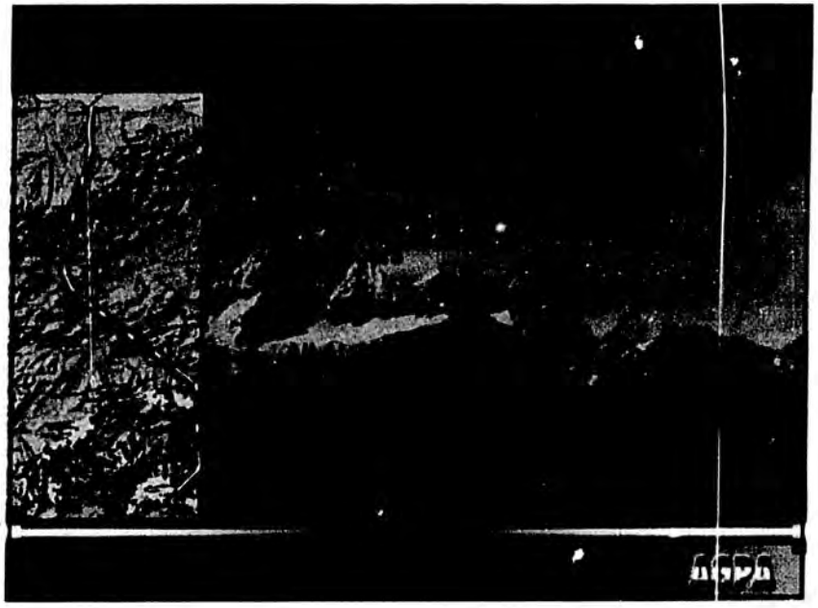






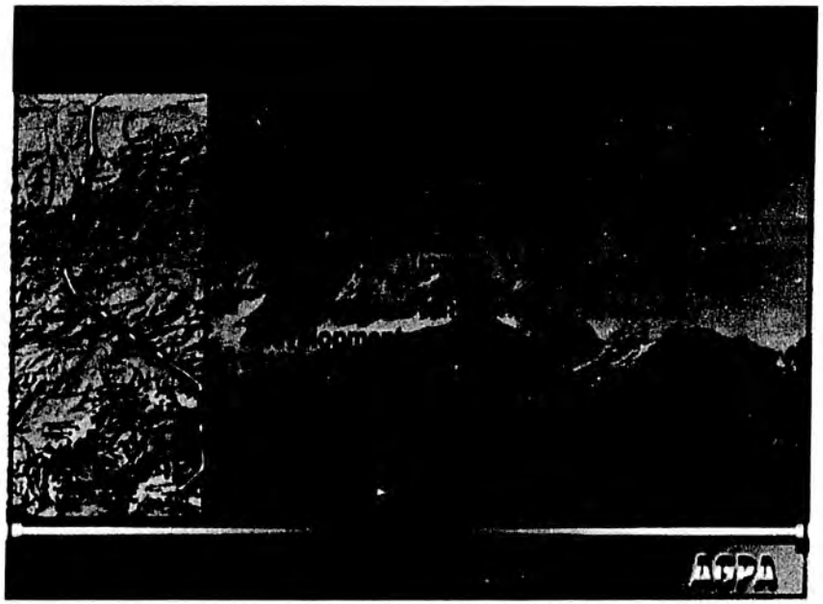











AGPA

Governor's Alaska Highway Natural Gas Policy Council



April 5, 2001

Presentation by

John Ellwood
Vice President, Engineering & Operations

Foothills Pipe Lines Ltd.

Foothills Pipe Lines Ltd. / Alaska Highway Gas Pipeline Project

My name is John Ellwood. I am Vice President, Engineering and Operations at Foothills Pipe Lines Ltd. ("Foothills"). We appreciate your invitation to discuss the transportation of Alaska North Slope natural gas to markets in the lower-48 states through the Alaska Natural Gas Transportation System ("Alaska Highway Project").

Let me begin by telling you about Foothills. Our Company is jointly owned by Westcoast Energy Ltd. ("Westcoast") and TransCanada PipeLines Limited. ("TransCanada"), the two major players in the Canadian gas pipeline business. Our corporate mission is very specific: to build and operate the Alaska Highway Pipeline Project. We were leaders in the project that was conceived twenty-five years ago, and we are just as committed today.

Between Westcoast and TransCanada, we have nearly 100 years of experience in developing, building and operating gas pipeline projects. We have been involved with every major Canadian gas pipeline project built in the last fifteen years.

Our existing pipeline systems provide access to five of North America's largest natural gas markets. Together, these systems have the capability to move fifteen billion cubic feet per day of gas from Western Canada to the consuming markets. Canadian gas accounts for almost 20% of all gas consumed in the United States and all of that gas currently moves through pipelines owned in whole or in part by TransCanada and Westcoast.

Attachment 1 shows the existing and planned pipeline network of Westcoast and TransCanada.

TransCanada, Westcoast and Foothills have developed leading edge gas pipeline design, construction and operating technology, including expertise in dense phase designs. We are also well known for our development of environmentally sound design, construction and operation practices. We believe that our expertise in northern, remote and difficult terrain gas pipeline construction and operations is second to none.

Building and operating pipelines is our core business.

The Alaska Highway Project is the Alaskan gas pipeline project approved in accordance with the Alaska Natural Gas Transportation Act of 1976 ("ANGTA") in the U.S., the 1978 Northern Pipeline Act in Canada, and the 1977 Agreement Applicable to a Northern Natural Gas Pipeline between the two countries ("U.S./Canada Agreement"). The project is shown in green on Attachment 2. As approved, the Alaska Highway Project is a 4,800-mile international pipeline project commencing at Prudhoe Bay and terminating in the Midwest and California market areas. It is important to note that the southern part of this pipeline has been constructed and is in full operation. The route for this system parallels the Trans Alaska Pipeline System ("TAPS") to Fairbanks, where it angles southeast, following the Alcan Highway to the Alaska-Yukon border with Canada, down through the Yukon Territory and northern British Columbia, and into Alberta. In Alberta, the pipeline splits into two legs. The Eastern Leg proceeds southwest, crossing the U.S.-Canada border at Monchy, Saskatchewan and terminating near Chicago. The Western Leg proceeds southwest, crossing the U.S.-Canada border near Kingsgate, British Columbia and terminating at a point near San Francisco, California.

Foothills and TransCanada are the two remaining partners of the Alaska Northwest Natural Gas Transportation Company (Alaska Northwest), a partnership formed to construct and operate the Alaska portion of the Alaska Highway Project. In addition, Foothills is the Canadian sponsor of the Alaska Highway Project, and the majority owner and operator of the Canadian portions of the Eastern and Western Legs of the Alaska Highway Project.

Foothills has continuously championed the Alaska Highway Pipeline Project from the very beginning.

The Project is back **"on the list"** of possible solutions to the current North American concerns about high energy prices and the adequacy of natural gas supplies.

At the outset, there are some basic points that we should delineate:

- It is important to remember that this pipeline crosses the territory of two countries with different regulatory and political regimes.

- The Project has a long history, which adds unique attributes. The permits which have been issued are a product of this history and to understand the former requires an appreciation of the latter. Significantly, ANGTA in the U.S. and the Northern Pipeline Act in Canada create expedited procedures for completing the chosen system, the Alaska Highway Project.

- The pipeline permitting process can be very time consuming. In addition to the substantial work already completed on both the Alaskan and Canadian portions of the Alaska Highway Project, the special legislative and regulatory procedures in place in the U.S. and Canada will assist in expediting the construction and initial operation of the Project and keeping unnecessary delays to a minimum.

Historical Background

As I indicated, there are important historical dimensions associated with this project. We might focus on the time frame 1976-1982. Originally, there were three competing Alaskan natural gas pipelines proposed. As shown on Attachment 3, two of the projects were overland pipelines through Alaska and Canada. The third project would have transported gas by pipeline to tidewater, following the route of the "TAPS" pipeline, where the gas would be liquefied and transported to California by liquefied natural gas ("LNG") tankers.

The U.S Congress enacted the Alaska Natural Gas Transportation Act of 1976 with a purpose to provide an expedited process with respect to the selection of a single transportation system for the delivery of Alaska natural gas to the lower forty-eight states and to expedite construction and initial operation of the chosen transportation system.

With respect to the transportation of Alaska North Slope gas to markets in the lower 48 states, ANGTA superseded the usual Natural Gas Act ("NGA") process for granting Federal regulatory authorization to construct and

operate a pipeline. ANGTA assigned the responsibility for the overall Alaska pipeline agenda to the President and Congress. Much the same approach was followed in Canada, where the Government took an active role in the decision regarding the Alaska natural gas pipeline. The reason for the creation of this extraordinary authority was that the governments wanted to expedite a cumbersome regulatory approval process in order to move more quickly to a solution.

Prior to 1978, a Canadian Board of Inquiry (The Berger Inquiry) examined a proposal to move Alaska gas across the North Slope and along the Mackenzie Valley. At the same time the National Energy Board ("NEB") held a hearing to determine which of the two overland pipeline routes was acceptable to Canada. Both processes rejected the North Slope route (primarily for environmental reasons) and the NEB recommended the Alaska Highway (Alaska Highway Project) option, being promoted by Foothills. The Berger Inquiry recommended that no pipeline should be built along the Mackenzie Valley for at least a decade and that a pipeline across the northern Yukon should never be built.

During this same period of time the Federal Power Commission (later to become the Federal Energy Regulatory Commission ("FERC") came to a split decision on the question of which route should be selected.

Following the enactment of the ANGTA, the President selected the Alaska Highway route and the Alaska Highway Project with his Decision and Report to Congress on the Alaska Natural Gas Transportation System ("President's Decision" or "Decision").

In 1977 just prior to the President issuing his Decision, the U.S. and Canada signed the U.S./Canada Agreement. This agreement or treaty, established the route, chose the companies who would build and operate the system, established tolling principles, and set the terms and principles to be followed in facilitating the construction and operation of the Alaska Highway Project pipeline. The President's Decision reflected the U.S./Canada Agreement. The Decision and the Agreement were subsequently approved by the U.S. Congress.

In 1978 Canadian Parliament enacted the Northern Pipeline Act. The Act:

1) incorporated all of the terms of the U.S./Canada Agreement

2) issued **statutory certificates** of public convenience and necessity to the respective subsidiaries of Foothills Pipe Lines Ltd.,

3) created the Northern Pipeline Agency to "*facilitate the efficient and expeditious planning and construction of the pipeline*

4) established the methodology and rules for setting the Canadian tolls and tariffs for the pipeline

5) selected the route for the pipeline across Canada and

6) established Terms and Conditions respecting the socio-economic, environmental, construction and operations matters.

The complete Alaska Highway Project is shown on Attachment 2.

The President's Decision designated Alcan Pipeline, a subsidiary of Northwest Pipeline Company (Northwest), as the party who would construct and operate the Alaska pipeline segment of the Alaska Highway Project. This authority was later assigned to Alaska Northwest, a partnership assembled by Northwest. At one time Alaska Northwest consisted of eleven (11) partners, all subsidiaries of U.S. or Canadian pipeline companies.

Given the magnitude of the pipeline undertaking Alaska Northwest sought to recruit the North Slope Producers to join the project and assist the financing of the pipeline. The Producers expressed a willingness to join but were restricted by the President's Decision that disallowed the producers taking an equity position in the pipeline. In 1981, President Reagan submitted and Congress approved a Waiver of Law package allowing producer participation and including in the project, the North Slope gas conditioning facility.

In 1980, before the Waiver of Law was passed, Alaska Northwest and the Alaska Producers entered into a Cooperation Agreement providing for joint funding of the design and engineering of the Alaska Highway pipeline and

the gas conditioning facility. Following the approval of the Waiver of Law, the scope of the Cooperation Agreement was expanded to encompass efforts to achieve the remaining regulatory approvals and to jointly pursue financing arrangements. The two sides anticipated that affiliates of the Producers would join the Alaska Northwest Partnership.

Design, engineering, environmental, financing and regulatory work proceeded along parallel tracks in Alaska and in Canada during this period of time.

As world wide energy supply and demand came back into balance and the "energy crisis" eased, the focus of the pipeline shifted to the pre-building of the southern portions of the Alaska Highway Project as shown on Attachment 4. There was a disagreement between Canada and the United States over this issue, primarily as it related to the export of Canadian natural gas to the U.S. market.

The Canadian Government was unwilling to authorize the Pre-build or the gas exports without further assurance from the United States that the entire Alaska Highway Project, including the Alaska segment, would eventually be completed. This assurance was forthcoming in a letter from President Carter to Prime Minister Trudeau, along with a Congressional resolution. As a result the southern Pre-build pipeline section was completed by 1982. This involved constructing 650 miles of 36 and 42 inch pipeline from Caroline, Alberta to Monchy and Kingsgate on the US border. The Pre-build and subsequent expansions were constructed pursuant to the Northern Pipeline Act and it's regulatory regime managed by the Northern Pipeline Agency.

When the Pre-build construction began it was widely anticipated that North American natural gas demand would quickly resume its upward trend. However the market did not recover as anticipated and demobilization of the Alaska Highway Project soon began.

In order to remobilize, we will be required to make modifications and enhancements to various elements of the Alaska Highway Project regime. Pipeline designs will have to be modified so that that the Project can respond to capacity and gas quality requirements of the shippers. We will have to incorporate the latest technology and techniques necessary to ensure that the maximum environmental protection measures are in place. We do not

expect any difficulty in introducing these revisions which are so obviously of benefit to all parties.

Clearly there is a lot of work still to be done. It is very important to understand is that the advantages that come with the unique ANGTA and NPA regulatory regimes far outweigh the alternative of starting from scratch. Using the existing statutes and treaty we can assist in having Alaska natural gas into the U.S. market sooner, with competitive transportation costs and at the same time reducing project risks for all stakeholders.

In our capacity as the managing partner of Alaska Northwest we have maintained the Alaska Highway Project in good standing. We have kept the project alive to ensure that the advantages and benefits of the Project could be used in remobilization plans to expedite construction of the pipeline. We particularly wished to preserve what we see as the "special and unique fast track" regulatory regime.

Foothills and its shareholders have expended time and effort to keep the permits current and to optimize the project design. We do not intend to quit the field now that success is within sight.

The Alaska Permits – Federal

A substantial amount of work has been completed by the Alaska Highway Project sponsors to date. Before discussing the specific permits held by Alaska Northwest it is important to better understand the unique regulatory and legislative framework under which these permits were issued, namely ANGTA.

ANGTA and the President's Decision remain in effect and can be terminated only by another act of Congress. ANGTA does not create a perpetual priority for the Alaska Highway Project. Rather, it establishes a priority designed to ensure that the Alaska Highway Project will be completed and begin initial operation in accordance with the decision of the President and Congress. Once the Alaska Highway Project is in operation additional projects may be considered under the Natural Gas Act.

In implementing this priority, ANGTA requires that Federal agencies and officers expedite and issue "at the earliest practicable date" all permits and authorizations required by the Alaska Highway Project. In addition, ANGTA provides that applications and requests with respect to permits and authorizations required by the approved system "shall take precedence" over any similar applications and requests. Furthermore, ANGTA limits the discretion of Federal agencies and officers to include in certificates and permits for the Alaska Highway Project any conditions that would obstruct the system's expeditious construction and initial operation.

As required by ANGTA, the FERC in 1977 expeditiously issued a conditional certificate of public convenience and necessity for the Alaska Highway Project. That certificate contains no expiration date and is still in effect today.

In addition, Alaska Northwest holds a federal right-of-way grant issued in 1980 by the Department of Interior's Bureau of Land Management. That grant does not expire until December 2010, and may be renewed at the request of Alaska Northwest.

Furthermore, Alaska Northwest holds two recently extended Clean Water Act wetlands permits issued by the Army Corps of Engineers in coordination with many other agencies. Those permits were extended through September of 2007.

While these various federal permits were issued some time ago, they all are valid today. Indeed, nothing in ANGTA or in the certificates and authorizations issued for the Alaska Highway Project thereunder provides for the expiration of the chosen system's priority because completion of the Alaska segment was postponed until the U.S. domestic market could support it. Rather, the Alaska portion of the Alaska Highway Project has been held in reserve until the need for additional natural gas arises in the Lower 48 states is such that this section can be completed. As sponsors we have actively protected the preserved Alaska segment by maintaining all necessary certificates and permits and actively overseeing the rights-of-way.

We recognize that these certificates and permits need to be "updated" to capture changes in technology, markets and environmental requirements. We will do such updating, and it can be done within the ANGTA

framework. To that end, a couple of additional points need to be emphasized before I move on to the State permits.

- First, ANGTA clearly envisions and provides for the ability to condition and to amend these permits. These powers are subject only to the limitation prohibiting changes in the "basic nature and general route" and actions that will "otherwise" prevent or impair in any significant respect the expeditious construction and initial operation of the Alaska Highway Project.

- Second, the Alaska Highway Project sponsors' requests for both new permits and amendments to existing permits must be given priority under ANGTA. This priority translates into a timing advantage for the Alaska Highway Project.

- Third, the authority of the Office of Federal Inspector, as transferred to the Secretary of Energy, also continues in effect today to expedite and coordinate federal permitting, enforcement of permit conditions, and facilitation and oversight of the construction and initial operation of the U.S. portion of the Alaska Highway Project.

- Fourth, ANGTA also provides for expedited and limited judicial review of actions taken by Federal agencies and officers.

- Finally, the Alaska Northwest Partnership is well along in permitting the Alaska Highway Project.

The Alaska Permits – State of Alaska

On the state side, Alaska Northwest has a pending State of Alaska right-of-way lease application. Recently, we have initiated discussions with the State officials regarding perfecting and processing the pending application. Also at the state level, Alaska Northwest holds certificates of reasonable assurances issued pursuant to Section 401 of the Clean Water Act and a determination of consistency with the Coastal Zone Management Act.

Additional Alaska Permits

While Foothills already holds the major permits necessary to construct the remainder of the Alaska Highway Project, there are additional permits and authorizations that will need to be obtained. For example, the Alaska Highway Project sponsors will need to acquire a permit under the Clean Air Act. However, these additional permits will be procured as the Project proceeds, and such procurement will not cause a delay in the expeditious construction of the Alaska Highway Project.

The Canadian Permits

On the Canadian side, Foothills holds two unique certificates or permits:

- Certificate of public convenience and necessity.
- Yukon right-of-way.

Certificate of Public Convenience and Necessity

The certificate of public convenience and necessity ("certificate") is the Order issued following a successful hearing before the National Energy Board (NEB) of a pipeline application. The information that is required to be filed for hearing purposes is delineated in regulation and includes details about supply and markets, environmental impact assessment, engineering, construction and operations plans and details about connecting pipeline facilities.

The preparation of the required hearing information generally takes one to two years to complete and the length of the hearing will be proportional to the level of controversy surrounding the issues.

Foothills has completed this phase of the process. We have the "certificates" that entitle us to build a pipeline, subject only to terms and conditions set out in the Alaska Highway Project regime.

The "certificates" are statutory. They were issued by the Parliament of Canada when it enacted the Northern Pipeline Act and are in keeping with the principles and intent of the U.S./Canada Agreement.

We acknowledge that the "certificates" were legislated 20 years ago and that some have raised questions about their scope and validity. Others suggest that the certificates are dated and accordingly must be reissued. The "certificates" are valid. We are on solid legal ground in this regard.

Changes to the pipeline design to accommodate new technical issues and improvements have previously have been granted by the Northern Pipeline Agency both at the time of the construction of the original Pre-build facilities and later during the facility expansion.

However, fundamental changes to the Canadian "certificates" would require changes to both the legislation and the treaty. For example, another project could not be approved under the Alaska Highway Project regime. Further, the Northern Pipeline Act (incorporating the U.S. /Canada Agreement) provides that the route for Alaska natural gas will be along the route set forth in Annex 1 to the U.S. /Canada Agreement i.e. the Alaska Highway route. In the face of the provision of the Northern Pipeline Act and the U.S. /Canada Agreement, a treaty with the force of law, it is difficult to see how the National Energy Board could entertain applications either for alternative pipeline routes for delivery of Alaska gas through Canada or applications by companies other than Foothills following the Foothills highway route for delivery of Alaska gas through Canada.

Given the above, we may well ask what remains to be done before the project can proceed?

First of all, we do not have a commercial arrangement negotiated with the Alaska North Slope producers or other shippers. Achieving this commercial arrangement is our number one priority. We are confident that the mutual interests of all sides will ultimately lead to satisfactory arrangements.

Following the successful completion of such a commercial agreement, there are a number of terms and conditions that must be satisfied. These are set out in the Northern Pipeline Socio-economic and Environmental Terms and Conditions. It is our view that the terms and conditions are broad enough to accommodate modern environmental, engineering and construction practices. In fact, we addressed this issue when we pre-built the southern portion of the Alaska Highway Project pipeline.

Detailed design and engineering work also must be completed and approvals must be obtained from the Northern Pipeline Agency. It is this mechanism that I referred to when I indicated that we had a "fast track" regulatory process.

The Yukon Right-of-Way

I will take a few minutes to describe the status of our right-of-way through the Yukon. Foothills has been granted an easement in the Yukon. The current term of the easement is September 2012 and provisions are in place to renew the easement for a further term of 24 years. It is important to note that the easement is protected under the Encumbering Rights provisions of the Umbrella Final agreement which has been signed by the Government of Canada, the Government of the Yukon and all of the Yukon First Nations. The Final Settlement Agreements that have been negotiated with the Yukon First Nations contain specific provisions relating to the easement. In addition, the compressor stations locations and permanent access to the proposed stations are protected.

What does this mean? From our perspective this translates into certainty of land tenure and a significant timing advantage. Foothills has developed an excellent working relationship with the Yukon First Nations over the years and we are building on that relationship. Like the Canadian "certificates" the easements also constitutes an important asset. An asset not easily replicated.

Conclusion

Let me summarize and focus on some of the key points.

Foothills is a Company with real pipelines and real customers.

When combined with our shareholders TransCanada and Westcoast, we transport 20% of all the natural gas consumed in the United States. And we have the know-how and the where-with-all to build the Alaska Highway Pipeline.

We have been involved in this project for 25 years.

We and our former partners have invested heavily to achieve the permits, certificates, rights-of-way and much of the engineering on the Alaska Highway pipeline.

A basic message that I want to leave with you is this, we have a...very unique and solid regulatory framework, it is a very valuable framework in terms of saving money and avoiding costly delays when building a pipeline. It is more than a collection of permits. It is a package, designed specifically to expedite building the Alaska Highway pipeline.

This framework can neither be duplicated nor terminated easily. It is a one-of-a-kind regime. I urge all Alaskans to take full advantage of it.

Finally let me raise one other issue and that is the matter of the pipeline route decision. Before we can move from discussion to action this must be resolved.

Ultimately all stakeholders must find some common ground and go forward.

So where do we go from here?

A commercial agreement between pipelines and producers is the next major mile post for the Project.

Once a satisfactory commercial arrangement is achieved ... the flag drops; from that point on we believe that our regulatory framework will allow "shovels to be in the ground" within 24 months.

This is a very large project. It will involve many companies. It will cost a lot of money and there will be lots of issues to address and benefits to share.

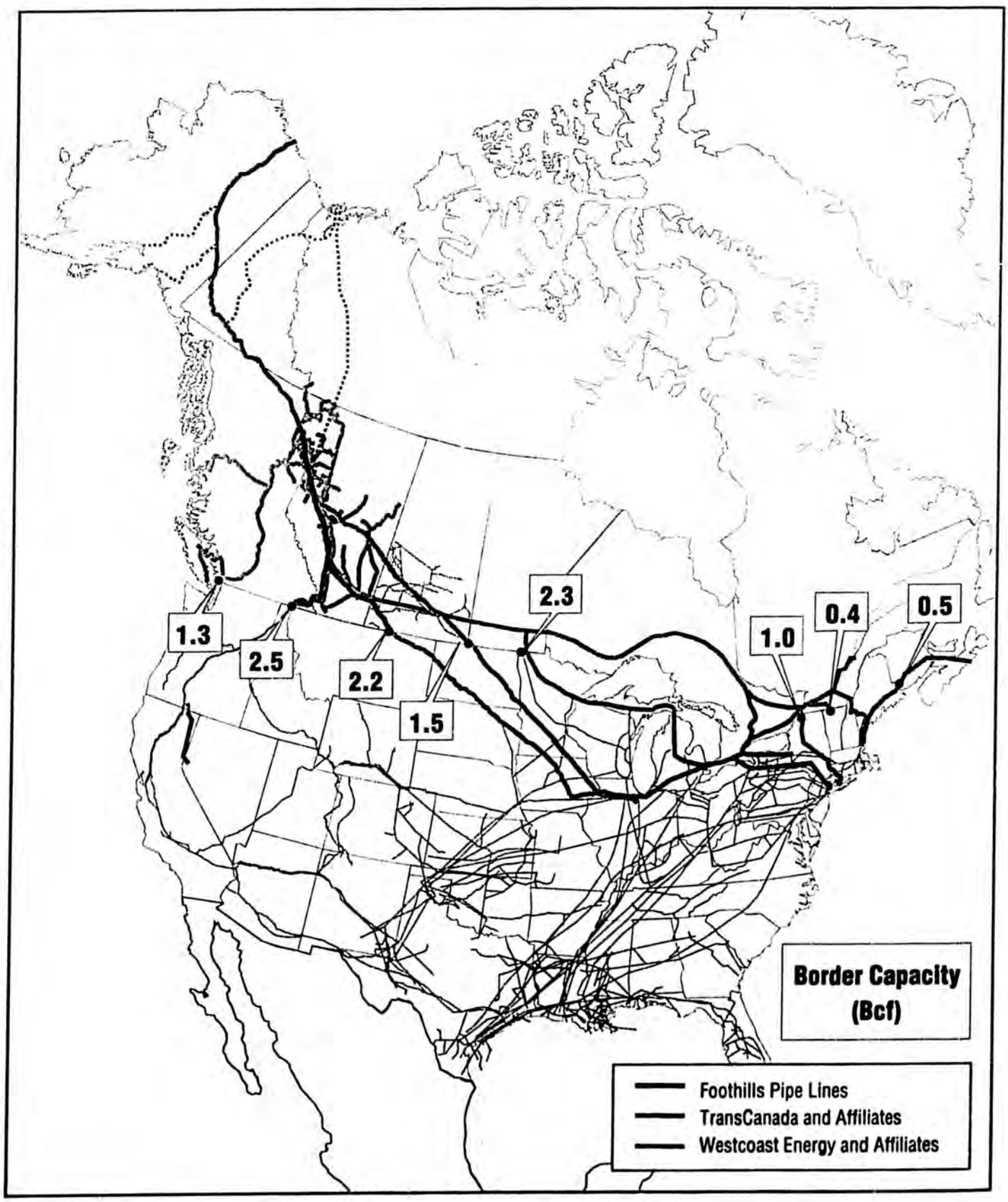
Foothills and its shareholders intend to be major players in the development and operation of this important pipeline and we believe that we bring value to the Project and value to Alaska.

Thank you, and I am now prepared for questions.

ATTACHMENT 1

FOOTHILLS PIPE LINES LTD.

NORTH AMERICAN PIPELINE INFRASTRUCTURE



CORRECTION

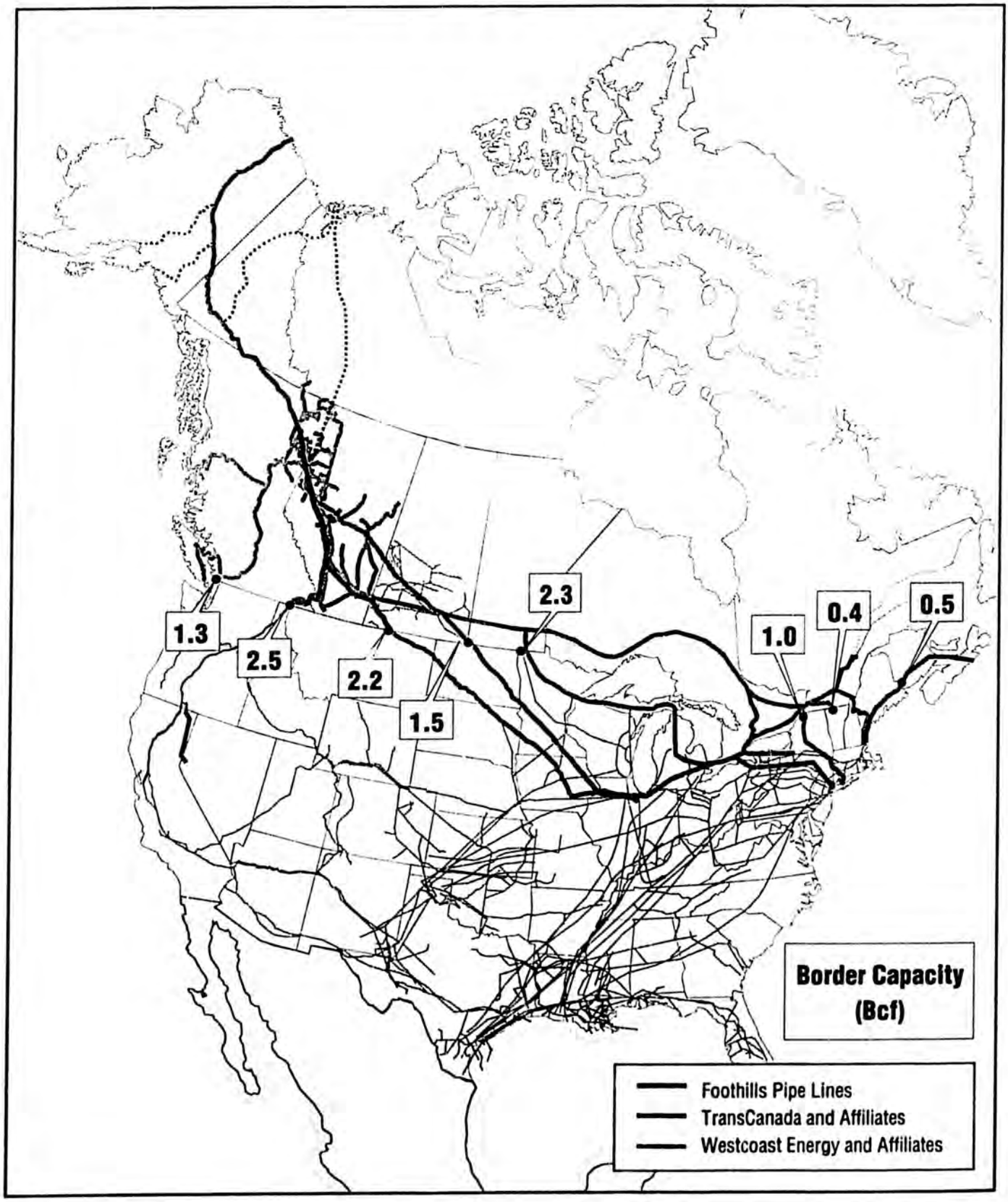
THE FOLLOWING DOCUMENT(S)
HAVE BEEN REFILMED TO
ASSURE LEGIBILITY OR PAGINATION

Central Microfilm Services
Department of Education & Early Development
State of Alaska

ATTACHMENT 1

FOOTHILLS PIPE LINES LTD.

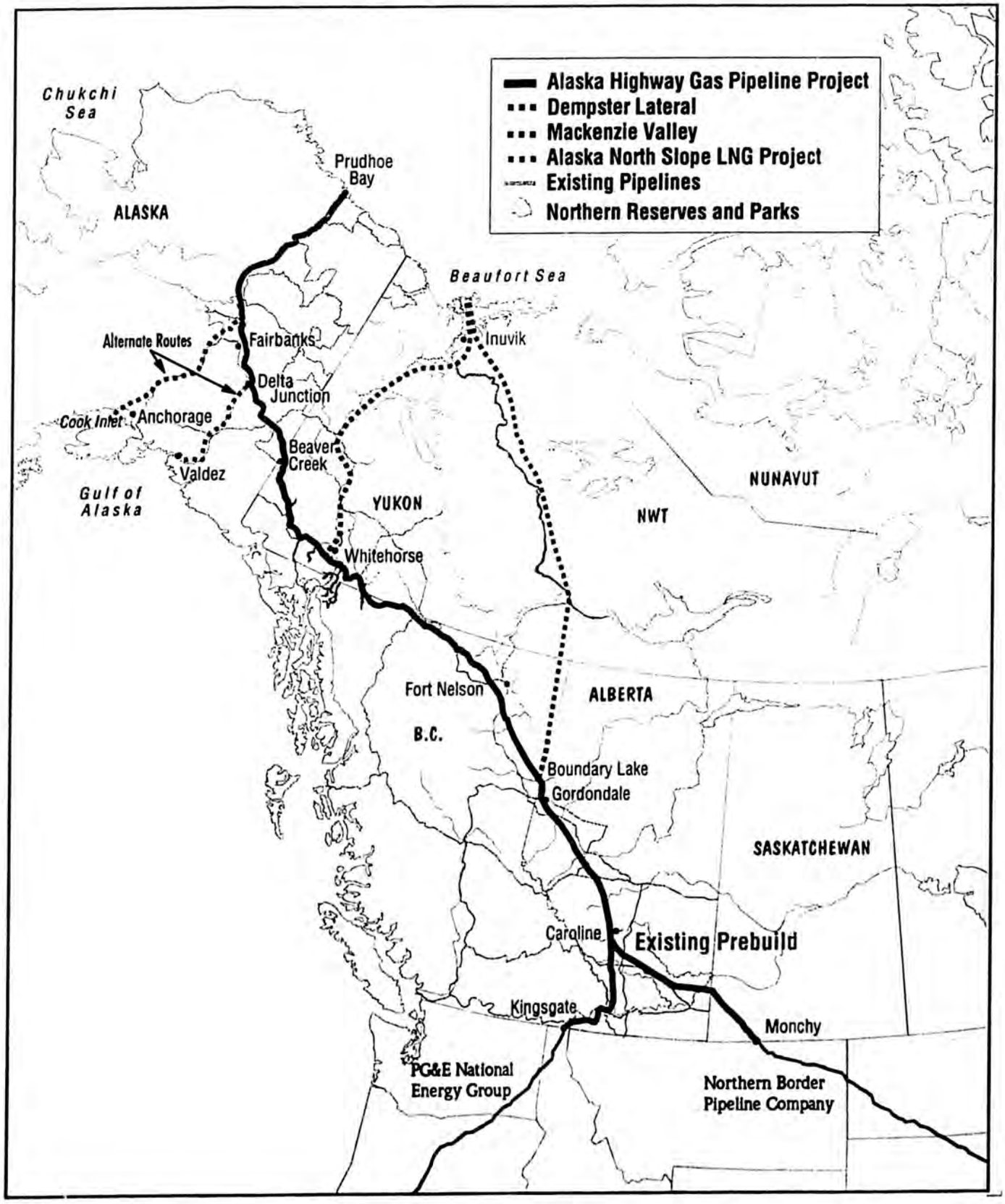
NORTH AMERICAN PIPELINE INFRASTRUCTURE



ATTACHMENT 2

FOOTHILLS PIPE LINES LTD.

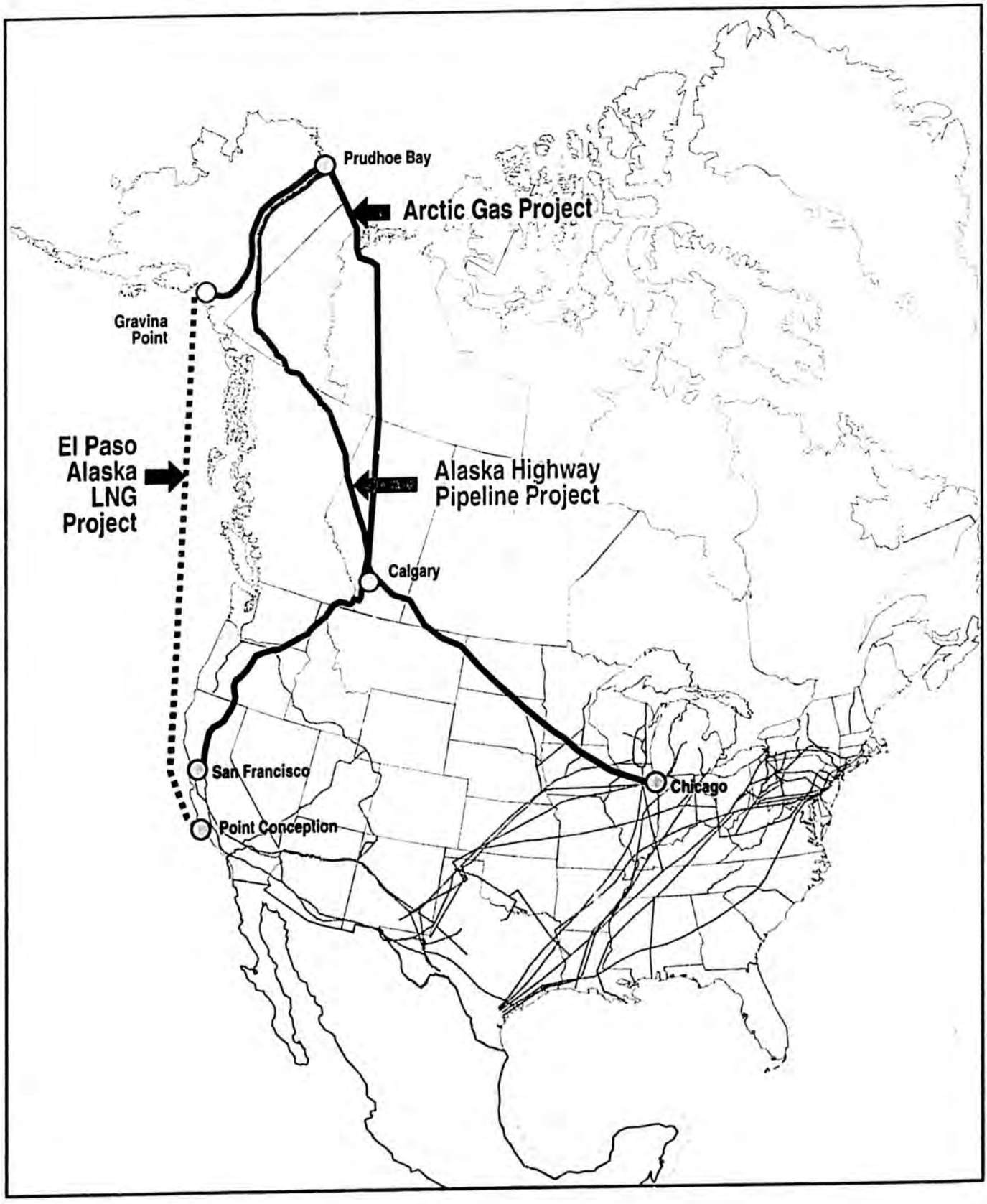
TRANSPORTATION SYSTEMS



ATTACHMENT 3

FOOTHILLS PIPE LINES LTD.

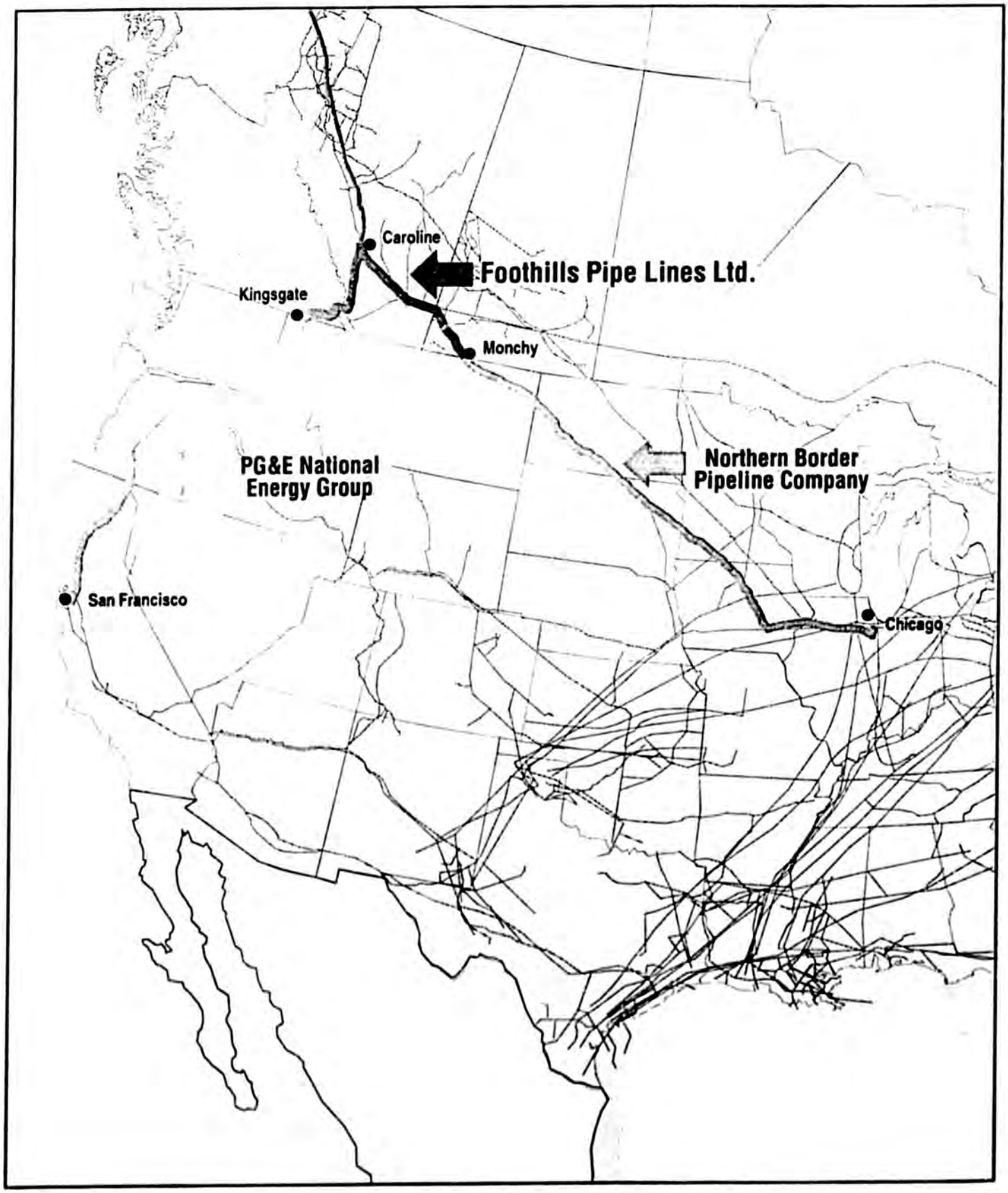
ORIGINAL COMPETING PROJECTS



ATTACHMENT 4

FOOTHILLS PIPE LINES LTD.

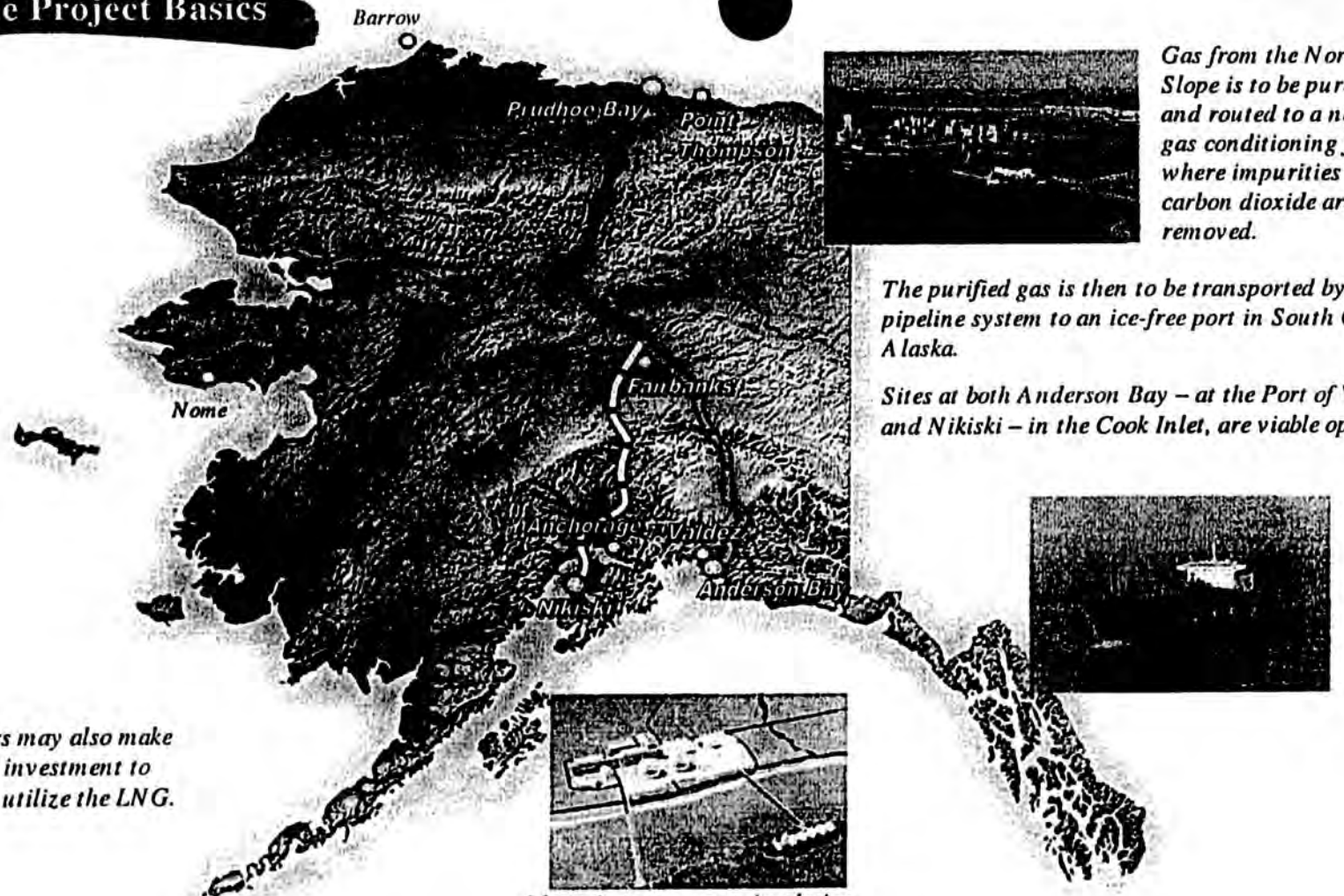
PREBUILD SYSTEM



ALASKA NORTH SLOPE LNG PROJECT

Phillips Alaska
BP Exploration (Alaska)
Foothills Pipelines
Marubeni Corporation

The Project Basics



Gas from the North Slope is to be purchased and routed to a nearby gas conditioning facility where impurities and carbon dioxide are removed.

The purified gas is then to be transported by pipeline system to an ice-free port in South Central Alaska.

Sites at both Anderson Bay – at the Port of Valdez, and Nikiski – in the Cook Inlet, are viable options.

LNG buyers may also make substantial investment to handle and utilize the LNG.

Above is a computer simulation of the potential Nikiski LNG plant and marine terminal site.

The LNG is loaded onto ships (much like large Thermos ® bottles) for transport to East Asian Markets.

In the LNG Plant, gas from the pipeline is chilled to -259°F (-160°C) so that it forms a safe, clean, liquefied natural gas (LNG).

- *MARKET UPDATES*
  - From well established, experienced and k...

- Marubeni
  - Japanese trading company, doing business throughout East Asia and the world
  - *Continuous feedback* through ANS LNG Market Liaison office
    - Providing significant input and updating to our market analysis

- Phillips
  - 30 years marketing to Asia (from Alaska)
    - Continual LNG market negotiations
      - Coordinated through international LNG group
  - Offices in Asia including: Tokyo, Taiwan and China (ongoing feedback)

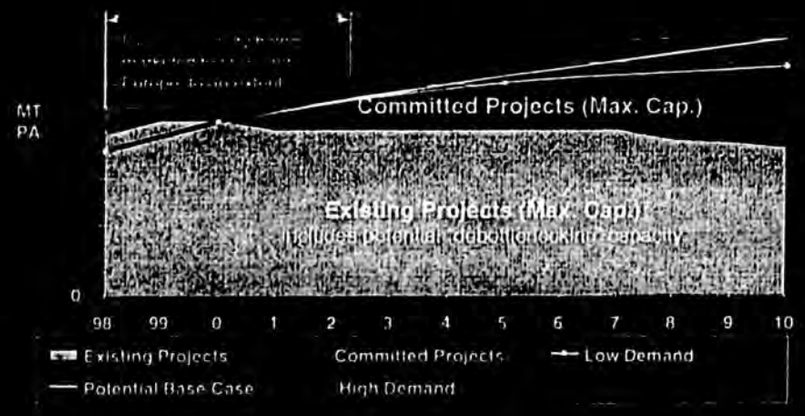
- BP
  - Ongoing worldwide LNG marketing experience
  - Offices in Asia (ongoing feedback)

Potential Asian LNG Projects

Country	Earliest Date of 1st Delivery	Customers	Nominal Capacity MTPA
Australia NWS	~2003+	Asian Markets	7.5
Malaysia Tiga (III)	~2003+	Asian Markets	7.6
Tangguh (Irian Jaya)	~2003+	Asian Markets	6
Qatargas/Rasgas	~2002+	Asian Markets	7.5
Bayu	~2003+	Asian Markets	3
Indonesia "I"	~2004+	Asian Markets	3
Yemen	~2004+	Asian Markets	5
Sub Total			39.6

Total Asia-Pacific Supply/Demand Outlook

Includes Emerging Markets (India, China, etc.)



Fiercely Competitive

Market Competition

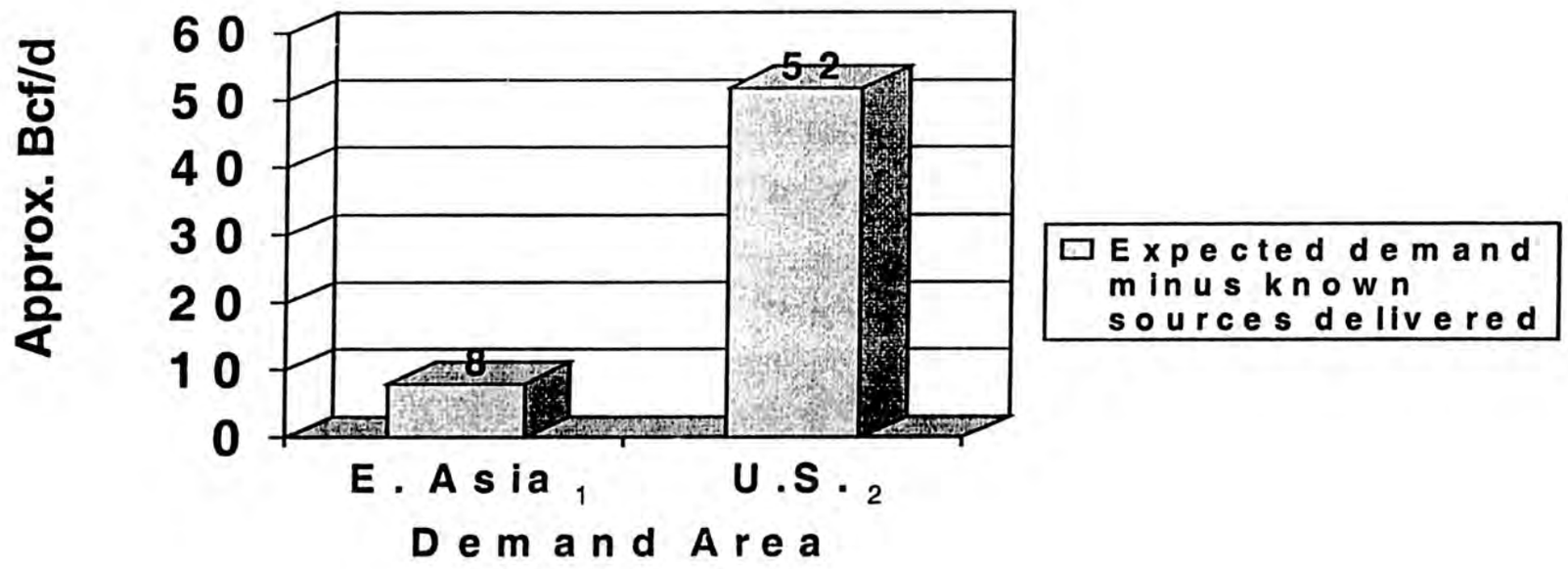
Potential Asian LNG Projects (cont'd)

Country	Earliest Date of 1st Delivery	Customers	Nominal Capacity MTPA
Gorgon	2004/5	Asian Markets	7.6
Sakhalin II	2005/6	Asian Markets	6
Alaska NS	2007+	Asian Markets	8 - 14.7
Indonesia Natuna	NA	Asian Markets	0
Sakhalin I	2007+	Japan/Asia	7
Sub Total			28.6 – 35.3
Total			~68 - 75

- **60-80 MTPA of potential projects**
  - **Pursuing 20 - 40 MTPA of 2010 growth**
- Problematic trends
  - Downward price pressure
  - Shorter contracts & spot deliveries

ANS LNG MUST ALSO COMPETE
WITH U.S. GAS DEMAND

2010 New Source Needs



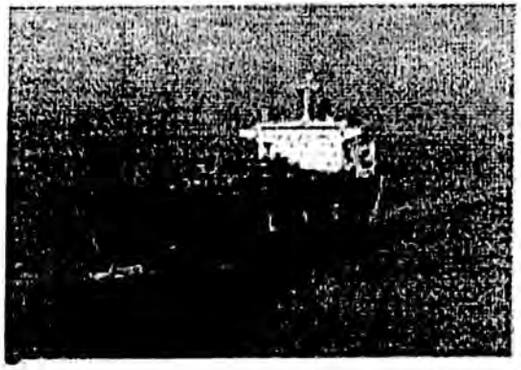
1 - High case LNG demand forecast of Tokyo Gas presented to 2001 HOAG
Year 2010 high demand of 135+ MTA (~19 Bcfd) minus ~80 Mta (11 Bcfd)

2 - National Petroleum Council, 12/99
2010 demand of 76 Bcfd minus 24 Bcfd of existing production

STAGE 1 WORK

Major Advance

- ***MARKET ENTRY PROJECT***
- 7-8 MM ton/year, projected $6.8 billion project
  - *Redesigned* to
    - defer cost to as-needed
      - minimize pre-investment
  - Improves market entry probability
  - Significantly reduces capital cost (and risk)
  - Expandable to 14 MTA as market develops

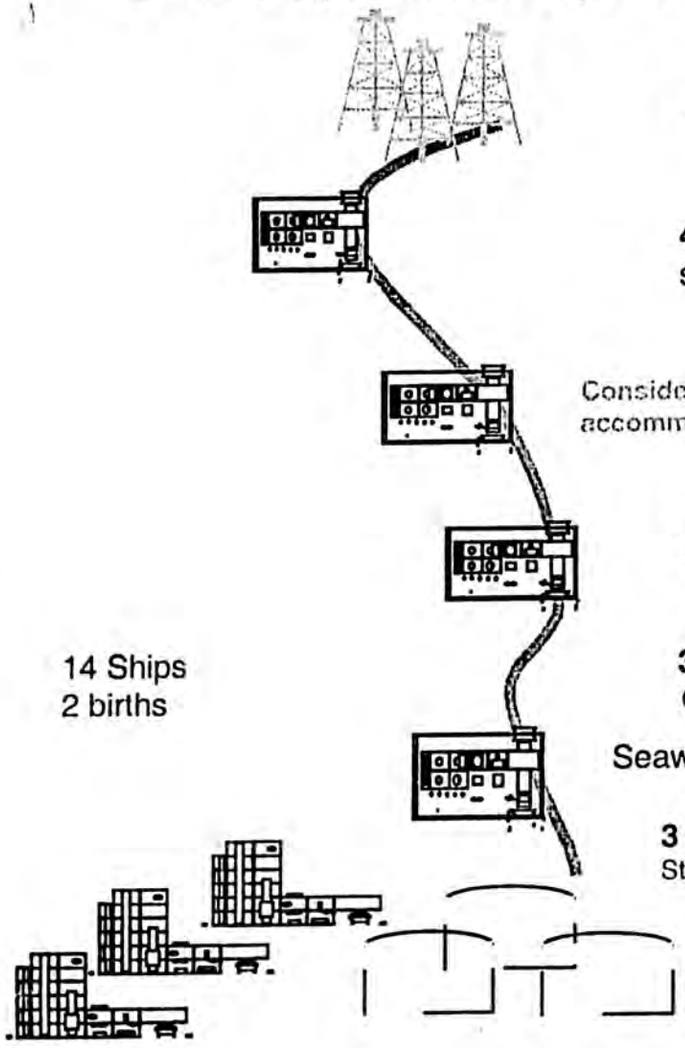


- **Mandate: to become economically sufficient at 7-8 MTPA even if future expansion never occurs**

On-site Asian LNG market discussions confirm:
Smaller market entry project preferred

KEY AREAS OF REDESIGN

- **Pre-Sponsor Group 14.7 MTPA**



2.1 BCFD

4 compressor stations

Considers instate sales accommodated as needed

36" p/l
2,400 psig

14 Ships
2 births

3 LNG Trains @ 4.7 each

Seawater cooling

3 - 167,000 m3 Storage Tanks

Valdez only

- **Sponsors smaller, market entry, 7 MTA expandable to 14 MTPA**

1.1 BCFD
expandable to 2.3 BCFD

ZERO compressor stations initially - expand up to 4 @ 7MTPA

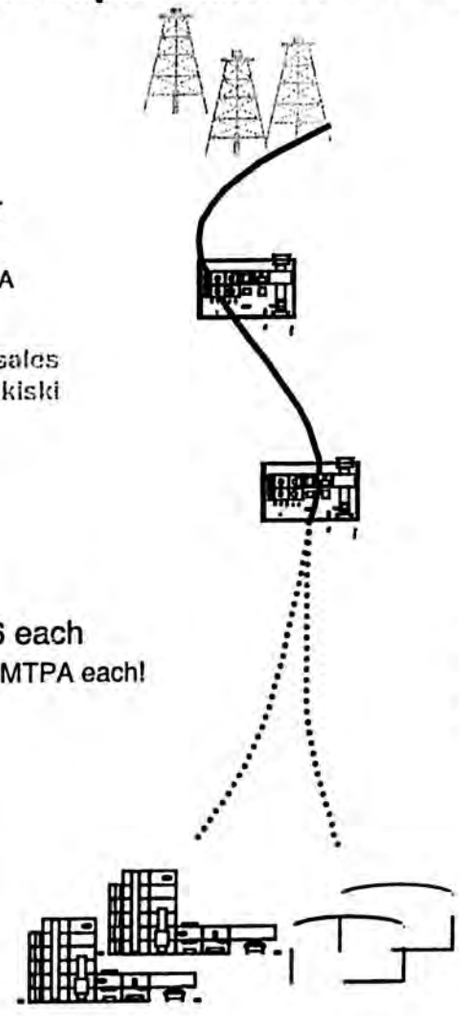
Provides for instate sales demand growth in Nikiski case

28/30" p/l
2,800 psig

2 LNG Trains @ 3.6 each
- EXPANDABLE TO 7 MTPA each!

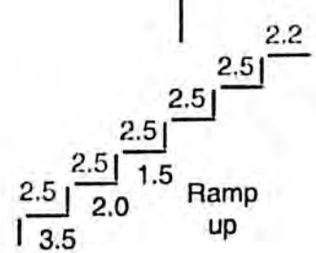
Air cooling

2 - 125,000 m3 Storage Tanks (pre- expansion)



7 ships
1 birth
(pre expansion)

Nikiski OR Valdez



STAGE 1 WORK

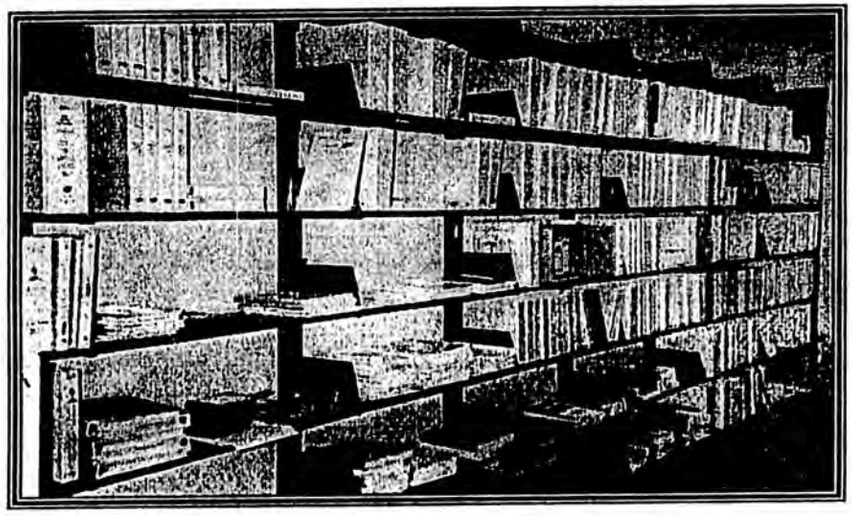


Photo: Stage 1 work library

- Stage 1 Documented Activities
  - 30+ Studies
  - 10+ Cost & construction estimates
  - 15+ Analysis & assessments
  - 30+ Reports
  - 25+ Workshops

- 26 Outside contractors/consultants (~60% AK content)
  - 15+ Engineering design & cost
  - 3 Permitting
  - 2 Regulatory
  - 2 Federal
  - 1 State
  - 1 Governmental entity

$12 Million - 18 months

STAGE 1 WORK COMPLETED:
ON TIME
WITHIN BUDGET
EXCEEDING ENGINEERING DESIGN EXPECTATIONS

PIPELINE ROUTE & LNG PLANT SITE

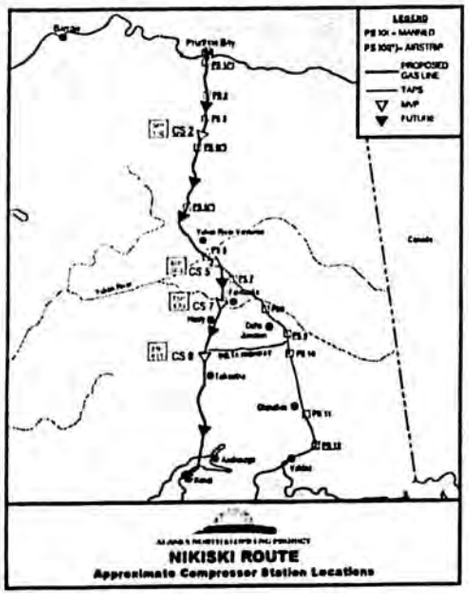
Pacing item is a cost competitive project - at either location

Neither site works if overall project isn't doable

Stage 1 engineering and construction design for BOTH

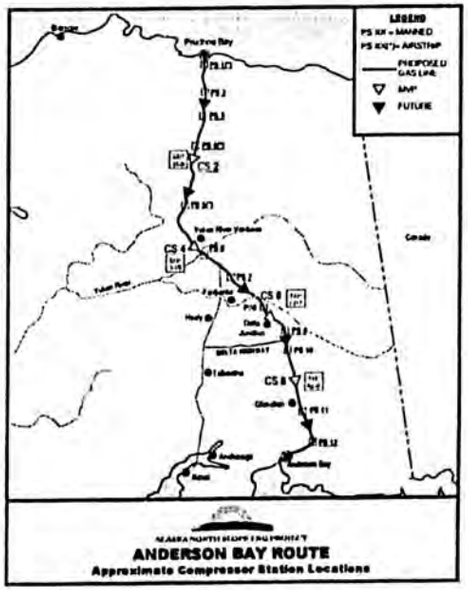
NIKISKI

- INSTATE GAS SALES POTENTIAL
  - Existing markets
  - Growth opportunity & existing infrastructure
    - Including Kenai LNG Plant
  - Potential lower cost instate gas
    - without need for long spur line to CI



ANDERSON BAY

- POTENTIAL FOR REDUCING PERMITTING TIME
  - Existing TAPS P/L corridor
    - Possibly less resistance
      - environmental
      - landowner, etc.



STAGE 1 - PERMITTING WORK

- **In depth analysis on route/site options**
  - Internal expert studies/review
    - Alaskan, Canadian, worldwide & world class experience and expertise
  - External, Alaska content consultant - extensive analysis

- **CONCLUSION: *Both* Anderson Bay and Nikiski can be permitted**
  - Any permitting time differences doable within current market timing needs
  - Opinion: Any existing Anderson Bay route permits will also require extensive work *and* cost to perfect

***Note*: Nikiski route does NOT go through Denali National Park**

STAGE 2

KEY AREAS OF FOCUS

- **Ongoing design/cost optimization**
- **Synergy of shared cost with a lower 48 pipeline project**
- **Value of public entity or port authority concept to our project**
- **Key risks, their impact and potential mitigation strategies** (including financing)
- **Alternate LNG markets evaluation**
  - Including U.S. and Mexico West Coast
- **Further understanding and valuation of competing LNG projects**
- **Further permitting analysis and execution strategy**
  - blue print for moving crisply forward - with the regulators and agencies
- **TIMING: 12-15 months (underway)** **COST: ~$3 million**

Key Stage 2 Highlights
To Date

- Additional capex optimization of ~$400 Million
  - Market entry 7-8 MTPA capex now at
    - **$6.5 B** - including ships
    - $4.9 B - without ships
    - Identification of further savings ongoing
      - also exploring shared facilities with a lower 48 gas pipeline
- Public entity valuation -- current view indicates no compelling advantage to a joint public/private project
  - Generally:
    - Benefits passed to private enterprise will be taxable
    - Public borrowing rates unlikely to offset
      - private entity deduction of interest and depreciation
- Other Stage 2 activity in progress and on schedule

ECONOMICS

- Key: cost competitive with other E. Asian LNG projects
  - **at a sufficient economic return**

- ANS LNG Project
  - is not yet cost competitive
  - is not yet economic on a cost of capital basis
    - for the expected risk

- Considerable, additional efforts required
  - To reduce cost
  - To share cost or find other synergy
  - Reduce risk
  - To achieve meaningful fiscal modification (particularly federal)

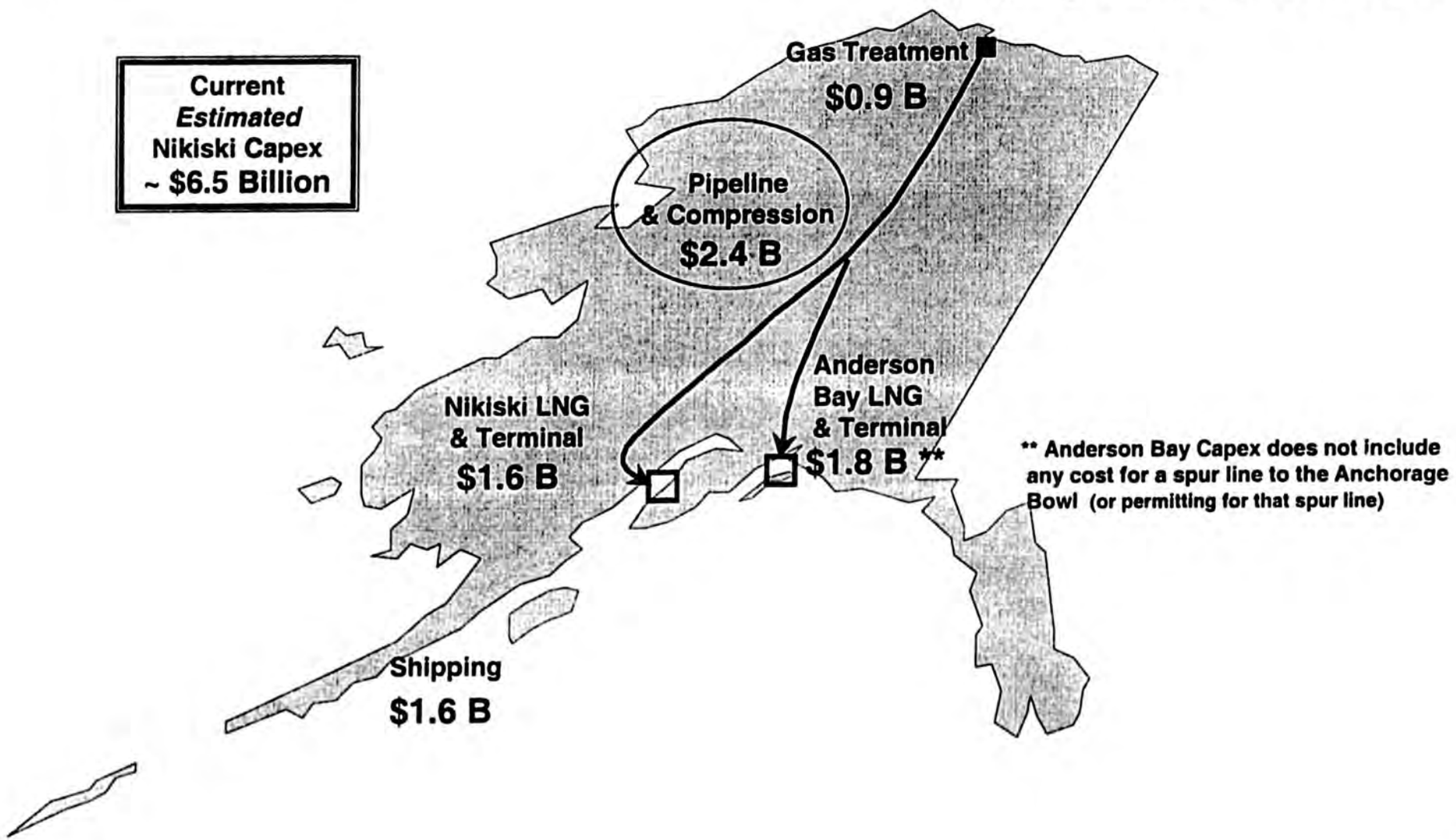
- ***Axiom:***
  - **Project economic assumptions must be salable**
    - Internally - to the investment community - to the suppliers and markets

ANS LNG Project
Current CAPEX Estimate

Working to improve economics
- **> Not yet determined cost competitive with other new projects**
  - > Other new LNG projects are already at tide water

Now exploring shared cost with a L48 pipeline

Current *Estimated* Nikiski Capex ~ $6.5 Billion



** Anderson Bay Capex does not include any cost for a spur line to the Anchorage Bowl (or permitting for that spur line)

Example LNG Project Cost Comparisons

From Public Sources

Ex-Production Development Costs* and Ex-Shipping

Potential ANS LNG Projects	Estimated CAPEX (US$Billion)	MTA	$Million per MTA	
ANS LNG Nikiski	$4.9	8.0	**$610**	
Backbone (ANS)	$7.3	9.2	**$790**	
Example other LNG Projects				
Qatar Ras Laffan (grass roots)	$1.7	5.2	$330	*O&GJ April 27, 1998*
Trinidad (grass roots)	$0.95	3.2	$300	*Energy Day*, June 1999
Oman (grass roots)	$2.0	6.6	$300	*Oman LNG Journal*, January 2001
E. Timor (grass roots)	$1.25**	4.8	$260	*Dow Jones Newswire, March 9, 2001*
Tangguh (grass roots)	$1.5	6.0	$250	*FT International Gas Report*, April 28, 2000
Malaysia III (expansion)	$1.5	7.6	$200	*WGI*, January 27, 2000
Industry Convention (rule of thumb)			***$250***	*O&GJ December 13, 1999*

ANS PROJECTS INCLUDES A *DEDICATED* - 800 MILE PIPELINE that OTHER PROJECTS DON'T HAVE
($2.4 B / 8 = $300)

Public information on development costs is limited but is more significantly related to oil production

MTA = Million metric tons per annum

***** Article quotes LNG Plant estimate at $2.5 billion in Australian dollars (~US$0.50)***



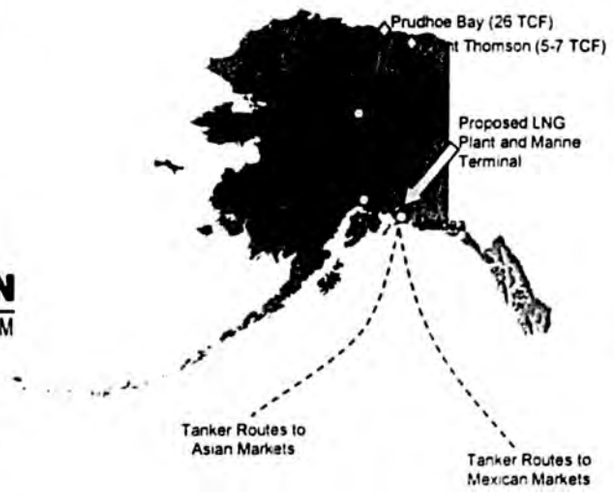
ALASKA NORTH SLOPE LNG PROJECT

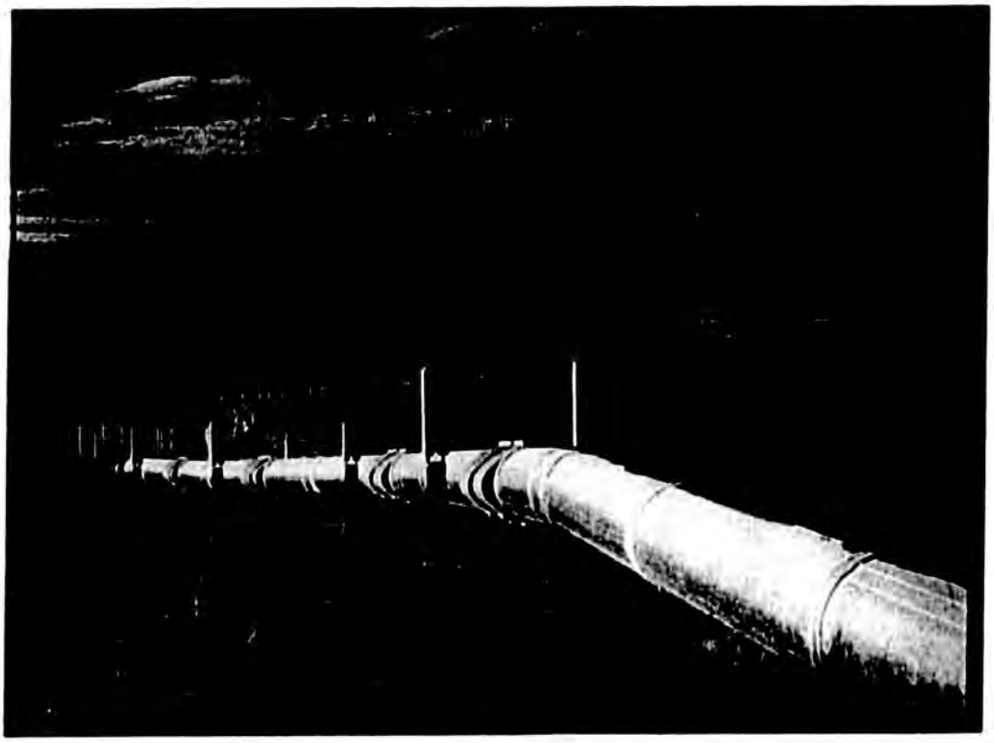
- Continuing effort
  - to develop a cost competitive project
  - to be prepared when the market is ready
    - but pragmatic about market timing

YUKON PACIFIC CORPORATION

TRANS-ALASKA GAS SYSTEM

CSX CORPORATION





I Want To Cut To The Chase About Alaska Gas

- Development of Alaska gas has been [illegible] will be challenging
- The myth that there's no market for Alaska L[illegible]
- The myth that Alaskan LNG is not an option
- The risk if we gamble that the overland route is the only option
- Your role

First:

Developing Alaska G[illegible] Is A Challenge

1970 - 2001

Arctic Gas
El Paso
Northwest/Foothills
ACETS
MACPORC
Kivalina/Wainwright
?? GTL
ARC
LNG Sponsor Group
YPC/TAGS

Key Facts Regarding Alaska Gas

- Alaskan north slope gas is located in one of the most remote areas of the world
- There is worldwide competition in both Asian and Lower 48 markets
- Any project from Alaska must be big to meet economies of scale
- Big projects require long term contracts to obtain financing

Any Alaskan project must be big in order to compete

- Economies of scale are required to co[illegible]ete with gas closer to market
- A gas pipeline is required that adds to cost
- In Alaska there are multiple gas producers who agree to a SINGLE project (vs projects elsewhere where they have individual)
- Investors will not invest $billions without confidence that they receive return on their investment

Unfortunately, the State and Producers have not been in a position to sell gas until June of 2000

But luckily now they want commercialization by 20

Prudhoe Bay Field Working Interest Ownership Status Before July 1, 2000
(2 separate "participating areas")

Owner	Oil Rim*	Gas Cap*	"Blended" Ownership (% of gas)
Sohio/BP	53.16%	14.82%	24%
Arco	20.27%	42.12%	37%
Exxon	20.27%	42.12%	37%
Mobil	2.09%	27%	2%
Phillips	2.05%	26%	
Others	2.16%	41%	
	100.00	100.00	100.00

Prudhoe Bay Field Working Interest Ownership Status After July 1, 2000 Major "Realignment"

Owner	Combination Oil & Gas (Tentative)	Actual Net* Gas Volumes Owned
Exxon/Mobil	36.8%	8+ TCF
Phillips	36.5%	8+ TCF
BP Amoco (Operator)	26.5%	5.82 TCF
Others	3%	
	100.00	22 TCF

* The Prudhoe Bay reservoir contains a gas volume (after CO_2 removal and future in-field fuel use) of 22 trillion cubic feet (TCF) of natural gas available for sale. 30% (6.6 TCF) of the gas is dissolved in the "oil rim". 70% (15.5 TCF) is in the "gas cap". 22 TCF is the equivalent of 418 million metric tons of LNG delivered to Asia.

Trillion Cubic Feet

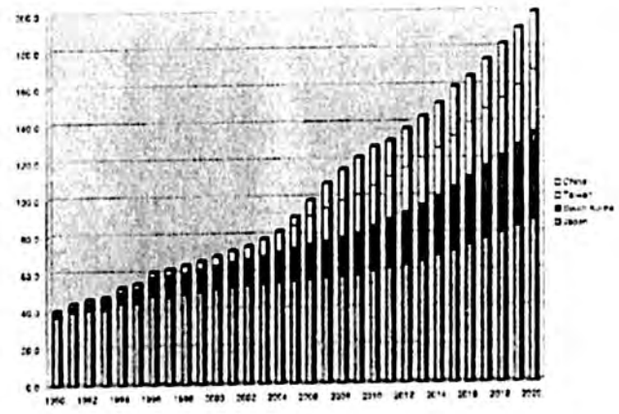
Note: The State of Alaska has a 12.5% royalty interest in both oil and gas at Prudhoe Bay.

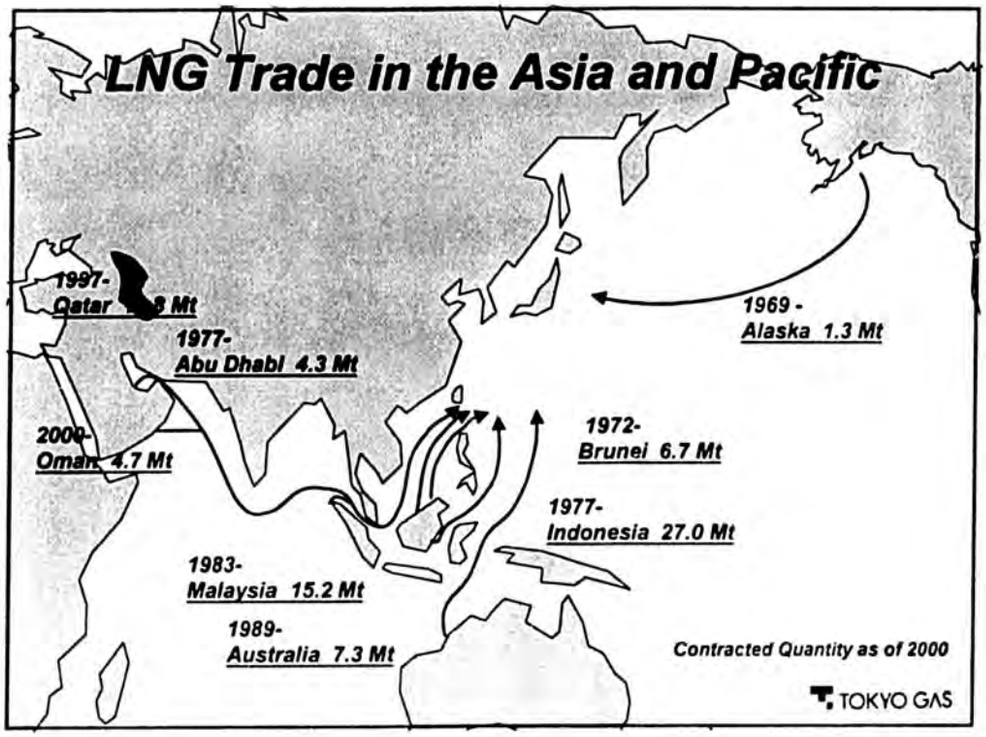
Second:

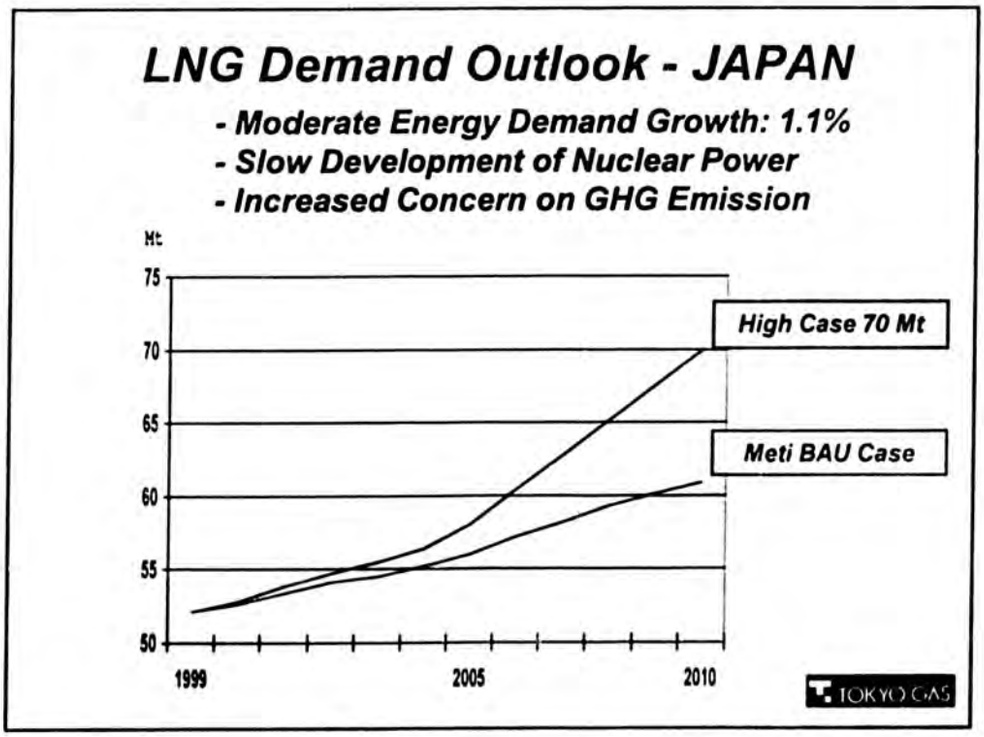
There is No Mark
For Alaska LNG?

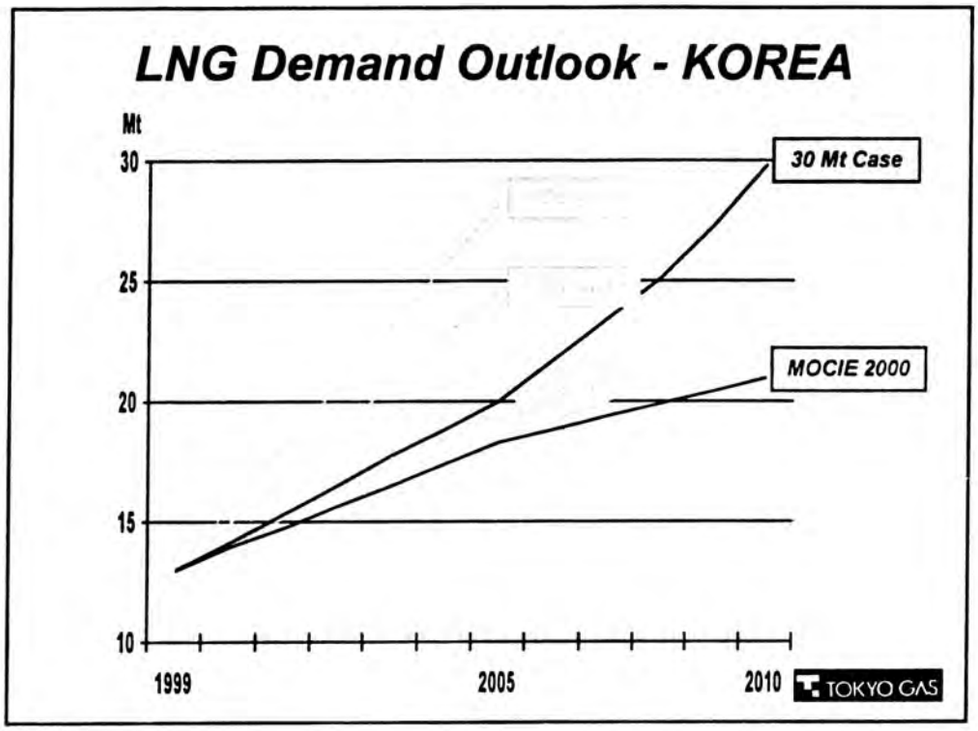
Worldwide demand for gas is increasing dramatically

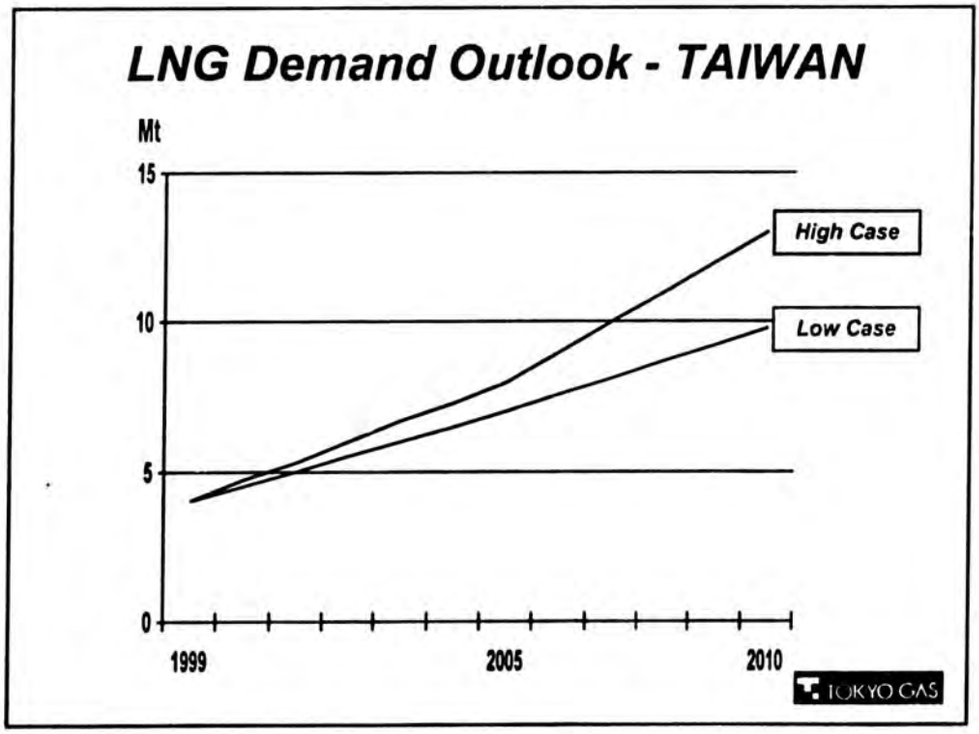
Standard & Poors LNG Demand Outlook (MMT)




LNG Trade in the Asia and Pacific
1997-
Qatar
Mt
1977-
Abu Dhabi 4.3 Mt
2000-
Oman 4.7 Mt
1983-
Malaysia 15.2 Mt
1989-
Australia 7.3 Mt
1969 -
Alaska 1.3 Mt
1972-
Brunei 6.7 Mt
1977-
Indonesia 27.0 Mt
Contracted Quantity as of 2000
TOKYO GAS

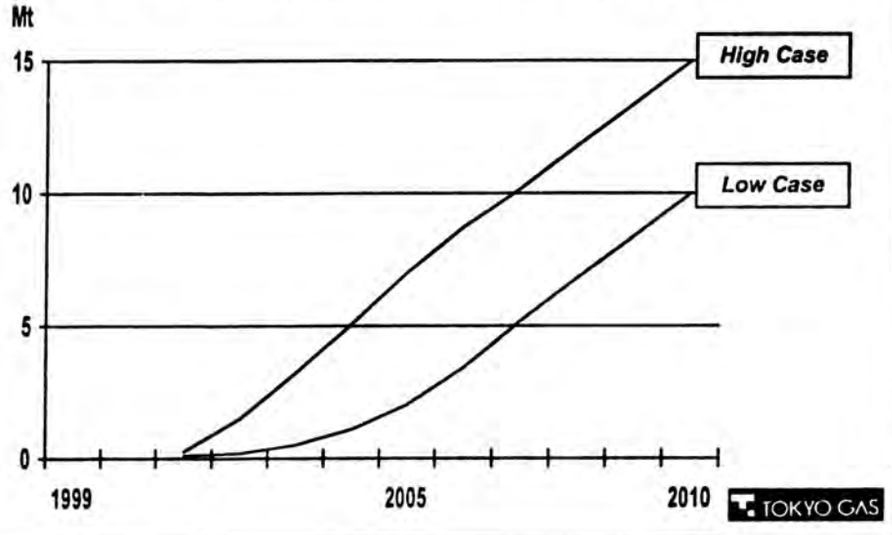

LNG Demand Outlook - JAPAN
- Moderate Energy Demand Growth: 1.1%
- Slow Development of Nuclear Power
- Increased Concern on GHG Emission
Mt
75
70
65
60
55
50
1999
2005
2010
High Case 70 Mt
Meti BAU Case
TOKYO GAS


LNG Demand Outlook - KOREA
Mt
30
25
20
15
10
1999
2005
2010
30 Mt Case
MOCIE 2000
TOKYO GAS


LNG Demand Outlook - TAIWAN
Mt
15
10
5
0
1999
2005
2010
High Case
Low Case
TOKYO GAS

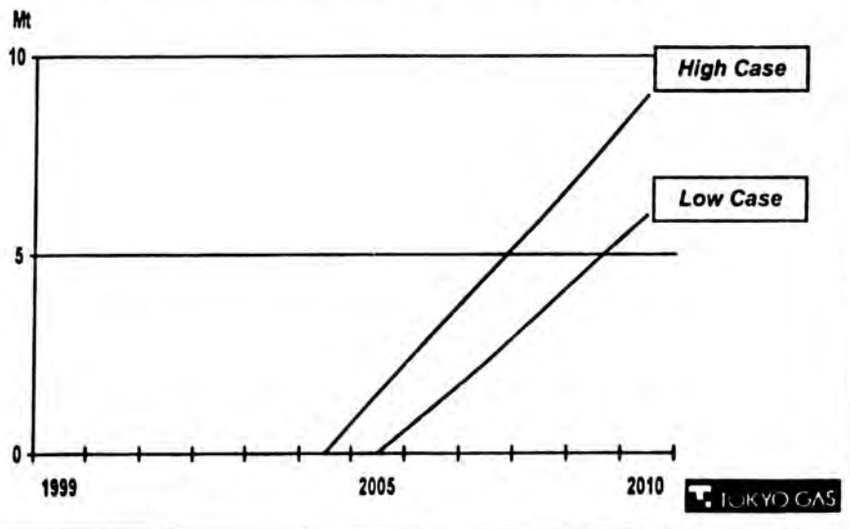
LNG Demand Outlook - INDIA

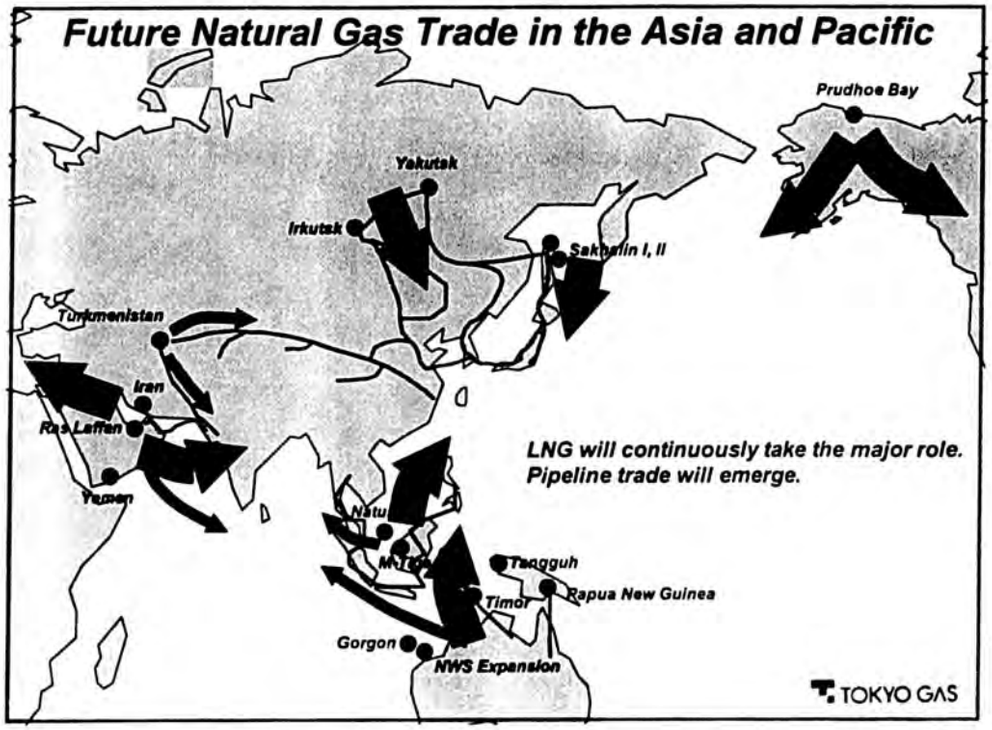
- Start of LNG Import: 2001 by Dabhol Power
- Potential Projects in Gujarat, Maharashtra, Tamil Nadu

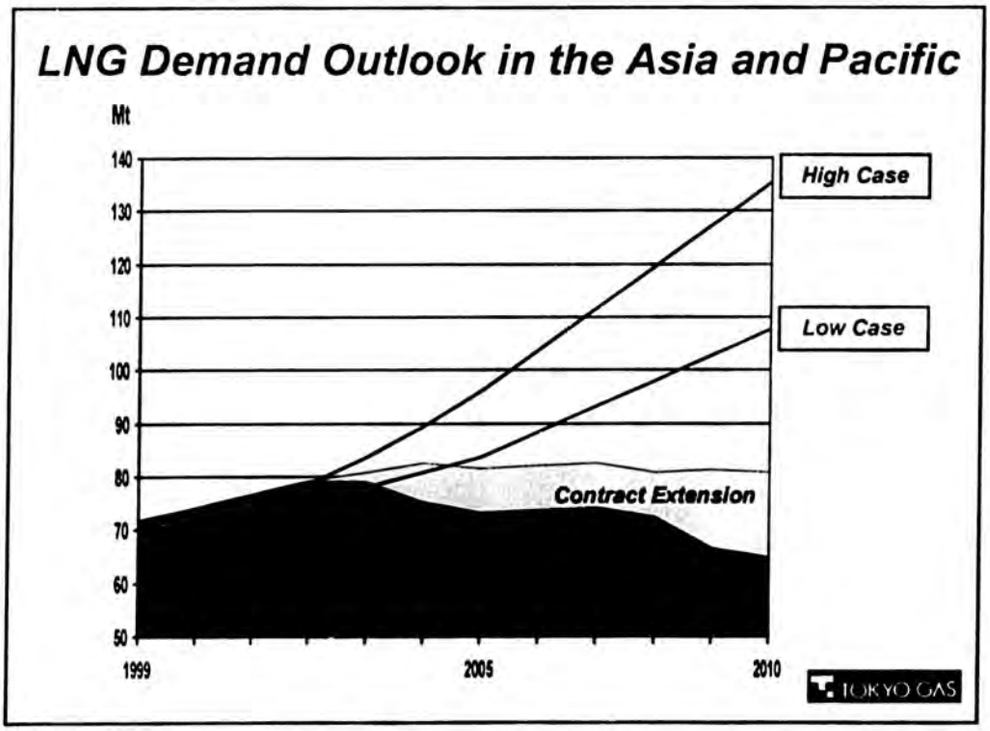


LNG Demand Outlook - CHINA

- First LNG Import Project: Guangdong, 3 mtpa, 2005
- Potential LNG Imports in Yantsu Delta, Fujan




Future Natural Gas Trade in the Asia and Pacific
Prudhoe Bay
Yakutsk
Irkutsk
Sakhalin I, II
Turkmenistan
Iran
Ras Laffan
Yemen
LNG will continuously take the major role.
Pipeline trade will emerge.
Natu
Tangguh
Papua New Guinea
Timor
Gorgon
NWS Expansion
TOKYO GAS


LNG Demand Outlook in the Asia and Pacific
Mt
140
130
120
110
100
90
80
70
60
50
1999
2005
2010
High Case
Low Case
Contract Extension
TOKYO GAS

Asia is Alaska's largest trading partner

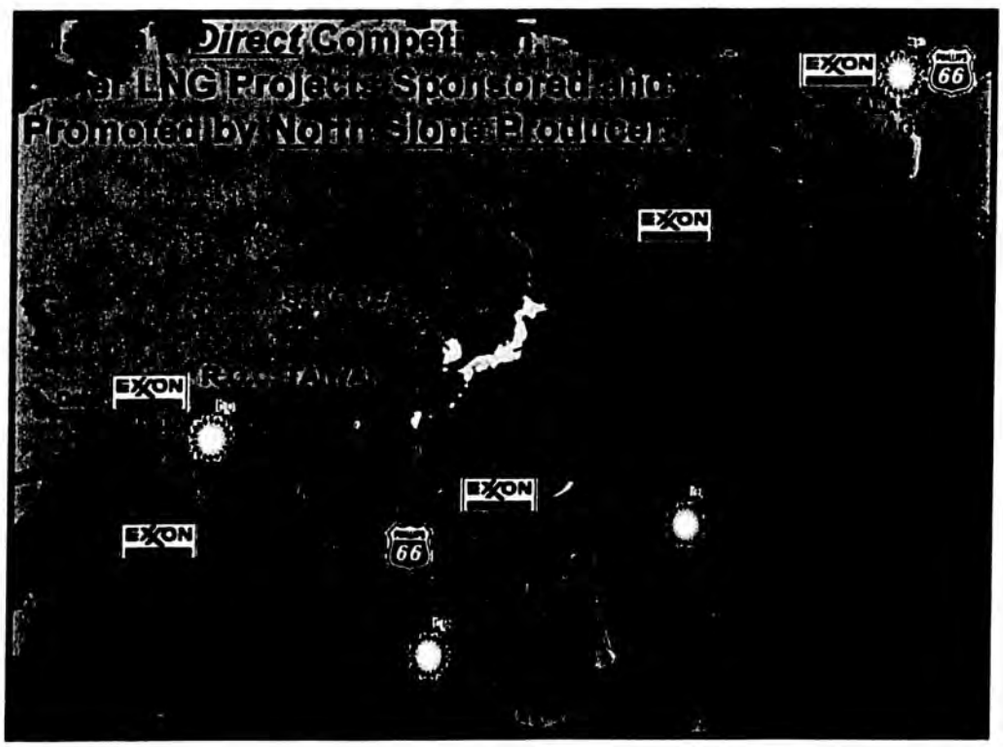
- Seafood
- Timber
- Coal
- LNG
- Why not more LNG?

FACT Pedro Van Muers stated that an Alaskan LNG project may be nibbled to death by other LNG projects around the world

• 1982: "only total of 7 MTPA new demand by 2000"	-	New demand in 2000 was over 4[illegible] MTPA
• "No market" in 1997	-	Qatar proje[illegible] 6.5 MTA
• "No market" in 2000	-	Oman project a[illegible]
• "No market" in 2007	-	**8.3 MTPA to West** *(Phillips, Chevron)* **25 – 50 MTPA** *(Tokyo Gas)* **50+ MTPA** *(Standard & Poors)*

(What if: Alaskan LNG was put first)

- Assume BP/Phillips/Foothills/Marubeni (Sponsor Group) "market viable" rate to Japan (8 MTA)
- Add Phillips' Australian project to Lower 48 (4.8 MTA)
- Add Chevron's Australian project to Lower 48 (3.5 MTA)
- Equates to a 16.3 MTA project from Alaska (TAGS at almost full out including proposed expansions)
- Economies of scale would be met and Alaska gas would be the most economic in all of Asia



Third:

LNG Is Not An Option For Alask

LNG Positives

- It is portable and can serve multiple m kets
- Offers diversity of supply from stable supplie
- Projects are backed by a long term sale contract
- TAGS LNG project has a smaller gas off take rate th the proposed overland project at 4 BCF so fewer gas producers must agree to dedicate gas to it

Alaska LNG is a stable supply

- Market price and proximity to market are not the only factors
- Arun plant recently shut down (10 MTA to Korea and)
- Stable supplies get market preference

  example

  Why are two Australian LNG projects bumping Tanguh which closer to the Lower 48 markets?

  PARTIAL ANSWER: stable government

Trans-Alaska Gas System – Year 2000 Project Update
Capital Costs ($US year 2000)

		START-UP	EXPANSION I	EXPANSION II
LNG Delivered	**MTA**	**9.2**	**13.8**	**18.4**
Pipeline Flow	BCFD	1.2	1.8	2.5
LNG Trains		2	3	4
Pipeline and Stations (1)	$billion	3.7	0.2	0.4
LNG Plant & Terminal (2)	$billion	2.3	0.9	0.8
Incremental Capital Cost	$billion	6.0	1.1	1.2
Cumulative Capital Cost	**$billion**	**6.0**	**7.1**	**8.3**

- Source: Willbros Engineering and Michael Baker Jr.
- Source: Kellogg Brown & Root and Air Products and Chemicals, Inc.

TAGS Cost of Service
Shows Alaska Gas is Competitive

TAGS estimated cost of service to Japan, excluding fuel
- $/mmbtu delivered, 13.8 MTA

	Low	High
Alaskan facilities	1.99	2.21
LNG tankers	0.70	0.70
Total	**2.69**	**2.91**

Fuel at 11.8%

Asian LNG Prices

Buyer	Seller	Jan. '01 $/mmBtu
Japan	Abu Dhabi	4.81
	Alaska	4.54
	Australia	4.89
	Brunei	4.65
	Indonesia	4.98
	Malaysia	4.80
	Oman	5.17
	Qatar	5.05
	AVERAGE	*4.88*

WGI March 8, 2001

- Prices are high in the Lower 48 and are also high in Asia
- Let's be consistent!

FACT

Remoteness is "taken care of" by reaching economies of scale

TAGS ~ 2.0 BCF

Foothills ~ 4.0 BCF

which is the great equalizer

Cost of Service to Supply Gas to Cook Inlet via Spur Line from TAGS at Glenallen

Basis: TAGS 3 train case at 1.8 BS

Volume to Cook Inlet	COS ($/mm
200 mmscfd	~ 2.00
400 mmscfd	~ 1.50

The Overland Proj ct

(Second) Honeymoon is clouding thi

FACT **Other gas supplies in North America nibble at the Lower 48 demand**

- McKenzie Delta
- Western Canadian Basin (BC and A ta)
- U.S. Rocky Mountains
- U.S. Gulf Coast
- Scotian Shelf

Or is it "Gobble up the Lower 48 Demand"

FACT

Other countries' LNG projects are also nibbling away at the overland pipeline project

- LNG imports to Lower 48
  - East coast 2000 - 0.6 [illegible]fd
  - East coast expansion capacity - 1.6 bs[illegible]
  - Phillips to west coast - 0.7 bscf[illegible]A)
  - Chevron to west coast - 0.5 bscfd (
- Two new west coast LNG projects plus east coas[illegible] LNG expansion will consume 2.8 bscfd of Lower 4[illegible] demand
- Represents 70% of the 4 bscfd overland project

Alaskan LNG alone bears criticism for "uneconomic Alaskan gas project"

- An LNG project to Asia was originally p[illegible]posed because overland pipeline project could [illegible]ompete in Lower 48
- The economic viability of other gas projects fro[illegible] Alaska have not been demonstrated
- TAGS is a well defined project using proven technology – cannot speculate to upside potential a[illegible] with other projects with less definition

When comparing projects from Alaska remember

- Worldwide LNG competes with Alaskan g[illegible] to both Asian LNG and Lower 48 markets
- Neither the LNG nor the overland pipeline proje[illegible] firm market commitments
- Hold conclusions until the honeymoon is over for overland project and firm costs and economics are developed

Path Forward

- **Set realistic goals (e.g. State ownership, hubs)**
- **Do what is right for Alaska – Identify and s[illegible]parate corporate interests from State interests and t[illegible] develop a balance**
- **Find out how much wellhead the producers really d[illegible] and need**
- **Figure out PBU and PT unit requirements that control producer actions and require changes if necessary**
- **Compare apples to apples**
- **Keep <u>ALL</u> options open**


YUKON
PACIFIC
CORPORATION
TRANS-ALASKA GAS SYSTEM
CSX
CORPORATION

Alaska Highway Natural Gas Policy Council
Fairbanks Public Meeting
Chena River Convention Center
April 18, 2001, 5 p.m. - 9 p.m.

I. Community Reception, 5:00 p.m. – 6:30 p.m.

II. Opening remarks from Mayor Boyles, 6:30 – 6: 35 p.m

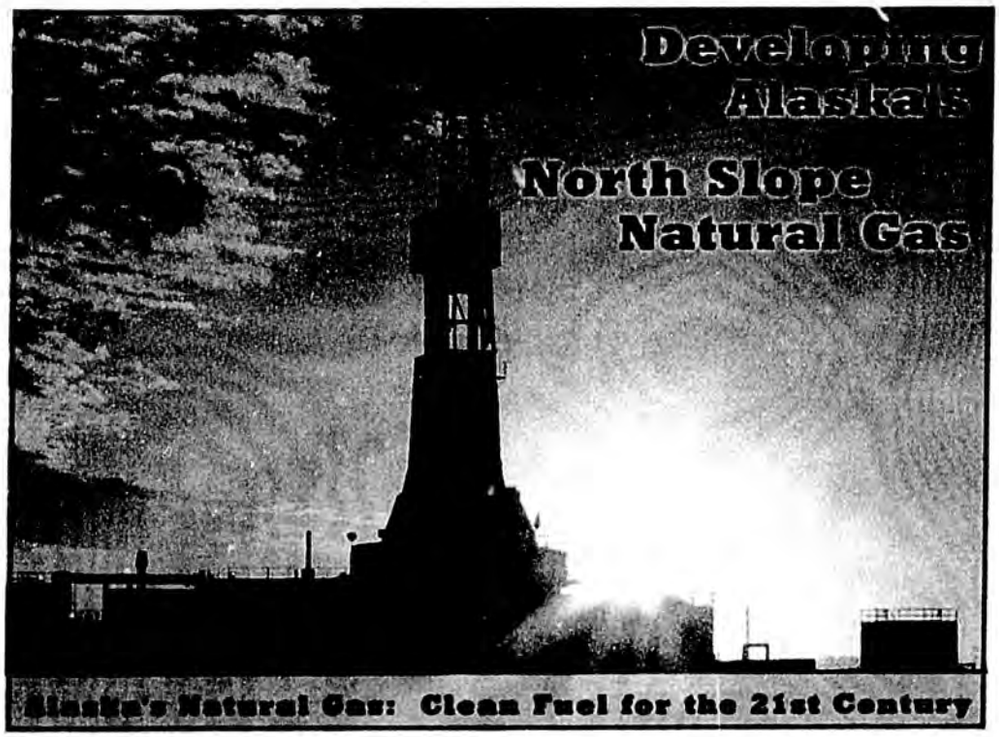
III. Opening remarks from Governor Knowles, 6:35 – 6: 45 p.m.

IV. Presentation from Commissioner Debby Sedwick, 6:45 – 7:00 p.m.

V. Presentation from Foothills Pipe Lines Ltd, 7:00 – 7:15 p.m. (see April 5 presentation)

VI. Presentation from Ken Thompson on "The Hub" concept, 7:15 – 7:30 p.m.

VII. Public testimony, 7:30– 9:00 p.m.



Mission

Develop and move Alaska's North Slope natural gas along the Alaska Highway route to North American markets and enable creation of gas industries in Alaska.



- Gas to North America
- Jobs and opportunities for Alaskans and Alaska businesses
- New energy sources for Alaska communities
- Future possibilities for use of North Slope gas including
  - Liquefied Natural Gas
  - In-State industrial development
  - Gas-to-Liquids
- Increased revenues to Alaska

Why Natural Gas?

It's here It's efficient It's clean



- There are known reserves of 35 trillion cubic feet of natural gas on the North Slope.
- Estimated resources are up to 100 trillion cubic feet.

Why Natural Gas?

It's here It's efficient It's clean

Natural Gas is the world's most efficient fossil fuel for generating electricity. Its other uses are for:



- residential and commercial heating and cooling
- energy to manufacturers
- feedstock for petrochemical products

Why Natural Gas?

It's here It's efficient It's clean

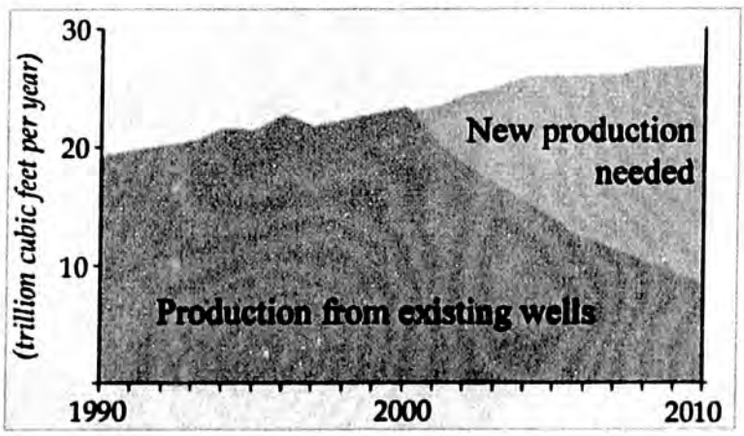


- Air emissions from Natural Gas are significantly less than those from coal or oil
- It is safer than nuclear energy
- It has less environmental impact and more year-round capacity than hydroelectric

Why Now?

Future demand Future is now

US Supply and Demand



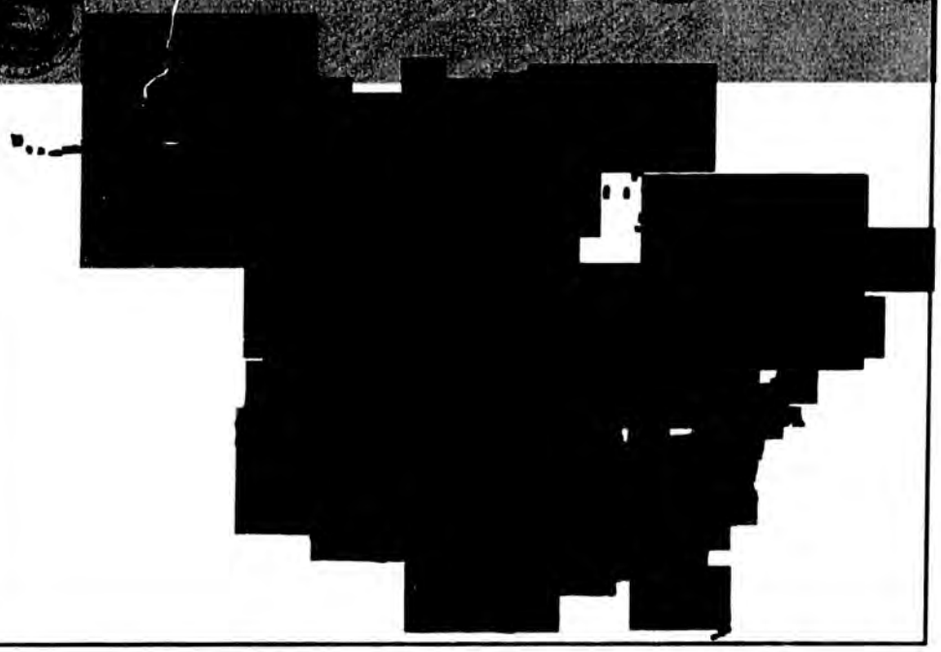
Why Now?

Future demand Future is now



- The North American gas market is the largest in the world and demand is growing.
- The long-term outlook for higher natural gas prices makes the development of North Slope natural gas feasible for the first time.

Why the Alaska Highway Route?



Why the Alaska Highway Route?

Building a gas pipeline along the Alaska Highway best meets the criteria of providing:

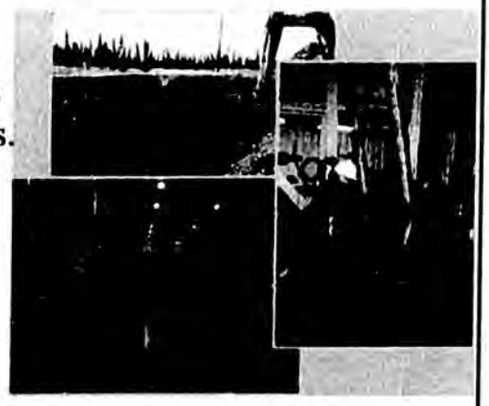
- Gas for America
- Jobs and opportunities for Alaskans and Alaska Businesses
- Energy for Alaska communities
- Multiple opportunities for use of North Slope gas
  - Liquefied Natural Gas
  - In-State industries
  - Gas to Liquids
- Increased revenues to Alaska for our resource
- Doing it right

Why the Alaska Highway Route?

Jobs Local Energy Future Opportunities Revenues Doing it Right

Jobs for Alaskans

- The pipeline will provide thousands of construction jobs and hundreds of operating jobs.
- Department of Labor and Workforce Development will ensure Alaskans have the necessary training and opportunities to build and operate the gasline.



The Alaska Highway route will enable more Alaska communities to access a new energy source. *Possibilities include*:





- Spur lines to communities to provide natural gas for home heating
- Gas fired power plants to generate electricity for Alaska communities

Why the Alaska Highway Route?
Jobs Local Energy Future Opportunities Revenues Doing it Right

Opportunities for North Slope Gas

The Alaska Highway route leaves open possibilities for other future in-state value added commercial uses of North Slope Gas.

- LNG – Liquefied Natural Gas
- Industrial Development
- GTL – Gas to Liquids



Increased Revenues for Alaska



- Total State Revenue is estimated at $200-400 million per year from:
  - Production Tax
  - State Property Tax
  - Corporate Income Tax
  - Royalty Share of Gas
- Alaska communities would also receive economic benefit.

Doing it Right

- Sound Science
  - Onshore gasline development uses proven technology.
- Responsible Stewardship
  - Utilizing existing infrastructure of oil pipeline and road minimizes environmental impact.



- Open Public Process
  - Stakeholder concerns will be addressed in public meetings organized by the Alaska Highway Natural Gas Policy Council.

Getting the best information possible

- Expert analysis by oil and gas and economic consultants including
  - Cambridge Energy Research Associates
  - Van Meurs and Associates, Ltd.

CERA

VAN MEURS
Energy Consultants

Knowles Administrative Action

- Gas Pipeline Cabinet
- Gas Pipeline Office
- Natural Gas Policy Council



What happens now?



- **Prepare:**
  - For permit applications by project sponsors expected this year.
- **Listen:**
  - To Alaskans - the Alaska Highway Natural Gas Policy Council will help solicit the views of Alaskans.
- **Coordinate:**
  - With federal agencies, such as Department of Interior and the Federal Energy Regulatory Commission and Canadian counterparts.
- **Advance:**
  - The Alaska Highway project through outreach to producers, pipeline companies, contractors, marketers and consumers.

How can you get more information?

Where can you find out more about an Alaska Highway gasline?

- Contact Ken Freeman:
  - Juneau (907) 465-3500
  - Anchorage (907) 269-7450
- Internet: www.gov.state.ak.us/gasline/
- Email: gasline@gov.state.ak.us
- Fax: (907) 465-3532

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672
2966 SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPLINES, 2001-02

http://www.gov.state.ak.us/gasline/



Alaska north slope natural gas...
the time is now

Vision:

Natural Gas Business And Gas Trading Hub/Principles For ANS Gas

Presentation to: Alaska Highway Natural Gas Policy Council

Fairbanks - April 18, 2001
Anchorage – May 24, 2001

Pacific Rim Leadership Development
Ken Thompson, President

Pacific Rim
LEADERSHIP DEVELOPMENT

Gas Business Vision: Introduction

- Producers completing studies to create their gas "vision"
- State should proactively complete its separate studies to create a "vision" that's best for Alaskans long-term
- State could make big mistakes by waiting for the producers to finish their "vision", then State reacts
- Producers' and State's perspectives will differ
  - Producers must focus on discounted present value, rates-of-return
  - State must focus on 50 years of socio-economic benefit to the state
- What proactive "vision" for the State should be examined?
- Find win-win with producers

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LEADERSHIP DEVELOPMENT

2

Gas Business Vision: Recommendations

- Gas pipeline traversing Alaska
- "Natural gas hub" near Fairbanks or Delta Junction: physical facilities *and* contractual system
- State retain 12.5% royalty share of gas "in kind"
- State (or Alaskan companies) invest at least 12.5% share in the gas pipeline from Slope to hub and hub facilities
- State formulate policies/regulations for clear and transparent valuation/pricing of gas at the hub

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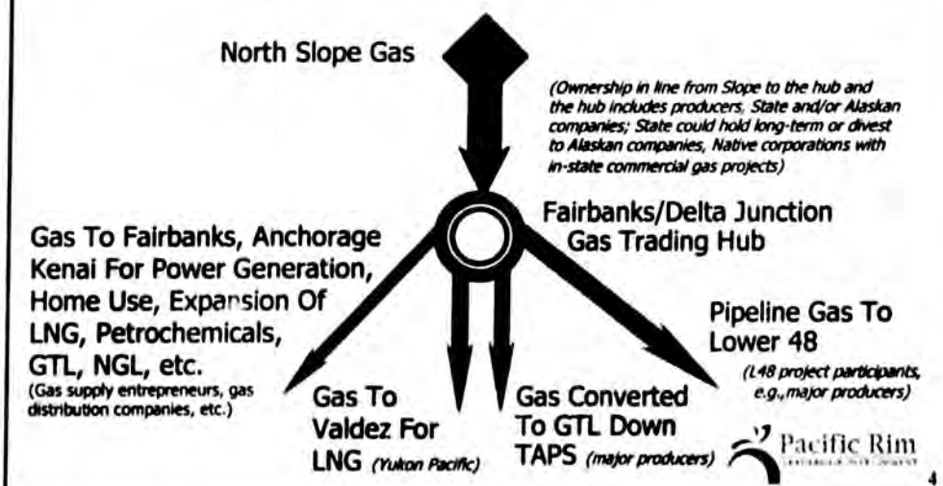
3

Trading Hub and Natural Gas Business Vision With Future Multiple Markets Access



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4

Gas Business Vision: Next Steps

- 2001-02: Resolution supporting principles of natural gas business in Alaska in conjunction with L48 gas line
- 2002-03:
  1) Regulations for clear, transparent netback pricing
  2) Rules for clear, transparent access for in-state use
  3) Rules for clear, transparent access for overseas markets
  4) State finalize decision of investment in line, gas "in kind"
- 2004-2006+: State attract investors for hub and/or spur lines, in-state distribution, city infrastructure, value added processing
- 2007: "GAS TO CASH" for Alaska, Alaskan companies, Alaskans!!!

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5

Alaska Natural Gas Business Coupled With Lower 48 Gas Line

Justification

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6

Gas Pipeline Traversing Alaska

- Lower 48 market appears best currently, but cyclical
- Northern route holds Alaska gas "hostage" to one cyclical market long term
- Southern route along TAPS route and Alaska highway provides access to future multiple markets
  - Alaska internal markets
  - Asia, West Coast U.S.
- State and Producers will see different calculations for northern vs. southern routes
  - Producers must focus on discounted present value, rates-of-return
  - State must focus on 50 years of socio-economic benefit to the state
- Find win-win solution for route traversing Alaska

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7

Natural Gas Trading Hub/Contracts

- Physical system and *contractual system*

Physical system

- Valves, manifolds that allow future pipelines to "plug in"
- Secure in-state markets, construct hub near Fairbanks or Delta Junction to facilitate market access
- *Alternative*: spur lines to select Alaska locations

Contractual system (must happen even if physical hub does not)

- Trading hubs fundamental to physical gas distribution but also for clear, transparent trading and price valuation
- Numerous trading hubs in the Lower 48, Canada, UK, Europe, progressing in Asia

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8

Natural Gas Trading Hub (continued)

- Assess regulations, guidelines, policies at such hubs for trading and netback pricing; institute at Alaska hub
- U.S., EU's Gas Directive, UK's Natural Gas Trading Arrangements are examples of regulations
- Formulate rules up front for access to in-state markets
- Access negotiations tougher later, when gas is flowing
- Precedence of NS facility access issues are negative

"Plug Into The Hub"

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9

State Retain 12.5% Share "In Kind"

- Lease agreements allow royalty payment or taking gas "in kind"
- Allows state to market its own gas to validate best market pricing being obtained
- State could choose to contract to third party gas marketing firm (e.g., Williams Energy, Enron)
- State's 12.5% share of gas is substantial at 250-500 MMCFD if total production is 2-4 BCFD
- State's volumes could facilitate in-state use and new business creation for economic impact

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State Invest 12.5% Share In Line/Hub

- State investment/transport in line from Slope to hub
- State contract with pipeline or Alaskan company for operational management of its investment share
- Best mechanism to accurately know and have input on transportation costs and operations
- Clear, transparent operating costs for valuation at hub
- State hold investment long term or divest to Alaska companies, Native corporations with in-state uses
- *Alternative:* if state does not invest, select Alaskan companies to invest 12.5% to transport State's gas
- Keeps more profits in state!

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11

State Mandate Valuation/Pricing Policies

- Precedents in Lower 48, UK NG Trading Agreements, EU Gas Directive
- For taxation, netback pricing must be clear, transparent
- Avoid controversies, hearing, lawsuits of past oil pricing disagreements
- Direct involvement by State in its own share of gas allows clear, transparent market pricing at hub
- Valuation/pricing mechanisms, methodologies known up front rather than after gas flowing
- Win-win when known up front

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12

Example Resolution Principles for Alaska - European Union Gas Directive

- Gas transmission, distribution interconnected, no barriers
- State(s) regulates gas business: nondiscriminatory, clear
- Fair and open access to the natural gas system
- Access to pipelines allowed under set of transparent rules
- Participants in the market will not abuse their dominant position nor engage in predatory behavior
- Participants have open, nondiscriminatory storage access
- Gas suppliers will compete freely for "eligible customers"

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13

Gas Business Vision: Conclusions

- Gas pipeline traversing Alaska
- "Natural gas hub" facilities Fairbanks or Delta Junction: physical facilities *and* contractual system
- State retain 12.5% royalty share of gas "in kind"
- State (or Alaskan companies) invest at least 12.5% share in the gas pipeline from Slope to hub and hub facilities
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Gas Business Vision: Next Steps

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LEADERSHIP DEVELOPMENT

15

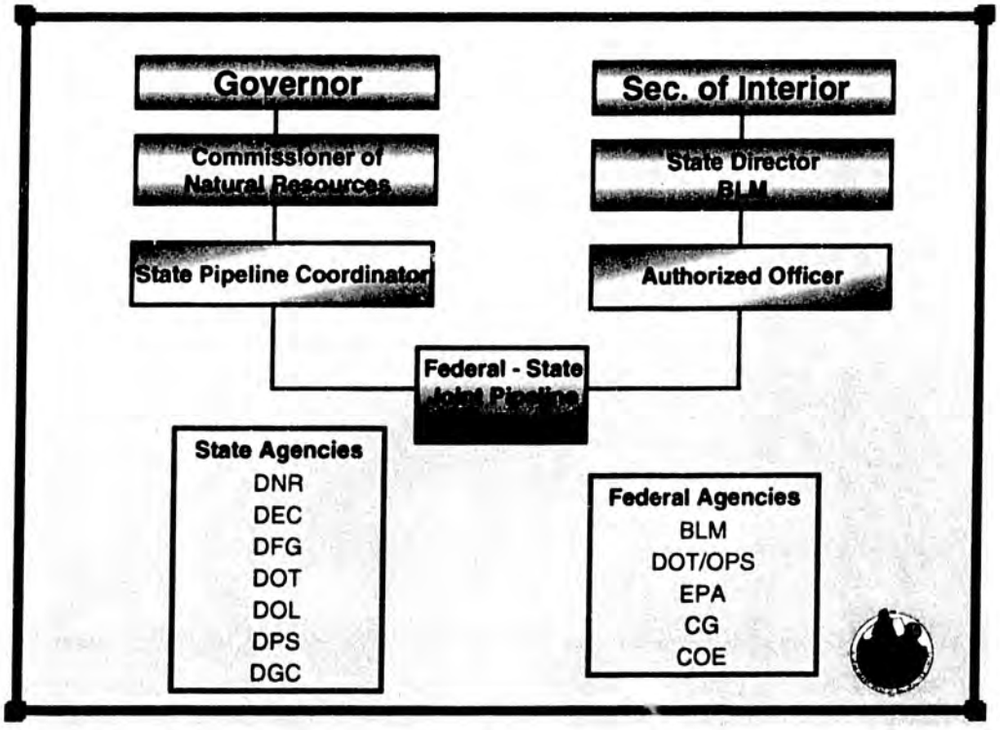
SCOMM

129:15

Alaska Highway Natural Gas Policy Council

Overview of the Regulatory Environment

William G. Britt, Jr.
State Pipeline Coordinator
Department of Natural Resources



Right-of-Way Leasing Act

Section
10. Legislative declaration of policy
15. Powers of the commissioner
20. Grant of right-of-way lease
30. Abandonment, reduction, or impairment of service of pipeline
40. Temporary or emergency service or temporary abandonment, reduction, or impairment of service by lessee
50. Application for right-of-way leases
70. Notice of application
80. Analysis and public hearing
90. Multiple applications for same lease
100. Decision on application
110. Term of lease
120. Covenants required to be included in lease

Section
122. Products pipeline leases
130. Right-of-way easements or leases acquired from others
140. Payment of rental and costs
170. Forfeiture of lease
180. Suits to enjoin or recover damages for defaults
190. Application of the Administrative Procedure Act
200. Judicial review of decisions of commissioner on application
205. Lease savings clause
210. Delegation of commissioner's authority
220. Continued operation of certain carriers
225. Binding effect of covenants
230. Definitions
260. Short title

Examples of Federal Authorizations for an Alaskan Gas Pipeline

National Environmental Policy Act	Lead Agency TBD
Certificate of Public Convenience and Necessity	FERC (interstate)
Dredge and Fill Permits	COE
Section 10 Permits	COE
Wastewater (NPDES) Permits	EPA/ADEC
SPCC Plans	EPA
Permit to handle Hazardous Waste	EPA
Radio/Wireless Communication Permits and Licenses	FCC
Airport Leases	FAA
Notices to Proceed	BLM
Material Sales	BLM
Land Use Authorizations	DOD, BIA, others
Bridge Permits	CG

Examples of State Authorizations for an Alaskan Gas Pipeline

Certificate of Public Convenience and Necessity	RCA (intrastate)
Right-of-Way Lease	ADNR
Land Use Authorizations	ADNR, UA, MHT
Water Appropriations	ADNR
Material Sales	ADNR
Burning Permits	ADNR and ADEC
Oil Discharge Contingency Plans	ADEC
Food Service Permits	ADEC
Solid Waste Disposal Permits	ADEC
PSD (Air Quality) Permits	ADEC
Water and Sewage Plan Approvals	ADEC
Habitat Protection Permits	ADFG
Utility Permits for Encroachment	ADOT
ACMP Consistency	DGC



Examples of Local and Private Authorizations for an Alaskan Gas Pipeline

Zoning Requirements and Land Use Permits	North Slope Borough
Development Permits	North Slope Borough
Road Plans	North Slope Borough
Zoning and Land Use Approval	Delta Junction
Leases, Rights-of-Way, Land Use Authorizations	Chugach, Ahtna, others



Technical Notes, Calculation Notes, Plans and Programs Likely to Be Required for an Alaskan Gas Pipeline

Access roads
Cathodic protection
Construction plan
Crack arresting burst test & analysis
Design basis
Earthquake design
Erosion & sedimentation control
Fire control
Full-scale bend test & analysis
Hazardous substance control & cleanup
Limit strain criteria
Mineral exploration & extraction
Overburden & excess material disposal
Pigging, valve & leak detection
Soils analysis/summary
Pressure design
Restoration
Siting of compressor stations
Solid waste management
Stress corrosion cracking evaluation
Trench & pipe stability evaluation
Welding procedure & ECA evaluation
Winter test trench summary
Construction camps
Communications
Corrosion control
Cultural resource preservation
Design summary
Environmental briefings
Expansion stress analysis
Flow analysis
Geologic hazards
Human-carnivore interaction
Material selection
NDE approach & summary
Permafrost design & operational analysis
Pipeline commissioning & start-up
Pipeline tie-ins
Quality assurance/quality control
River training structures
Snow & ice workpads & access roads
Stream, river & floodplain crossings
Surveillance & maintenance
Visual resources
Wetland construction
Yukon river crossing



Administrative Order 187

- Single point of contact for permitting, authorizations, and oversight
- Coordinated process for permitting, authorizations, and oversight
- Similar terms and conditions in permits and authorizations
- Unified voice in dealing with federal and Canadian governments, pipeline companies, and gas owners
- Use existing structures to address these issues



Administrative Order 187

Gas Pipeline Cabinet

Commissioners of:
- Alaska Department of Natural Resources (Chair)
- Alaska Department of Environmental Conservation
- Alaska Department of Fish and Game
- Alaska Department of Revenue
- Alaska Department of Transportation and Public Facilities
- Alaska Department of Labor and Workforce Development
- Alaska Department of Community and Economic Development

Directors of:
- Division of Governmental Coordination
- Governor's Washington D.C. Office

Attorney General



Administrative Order 187

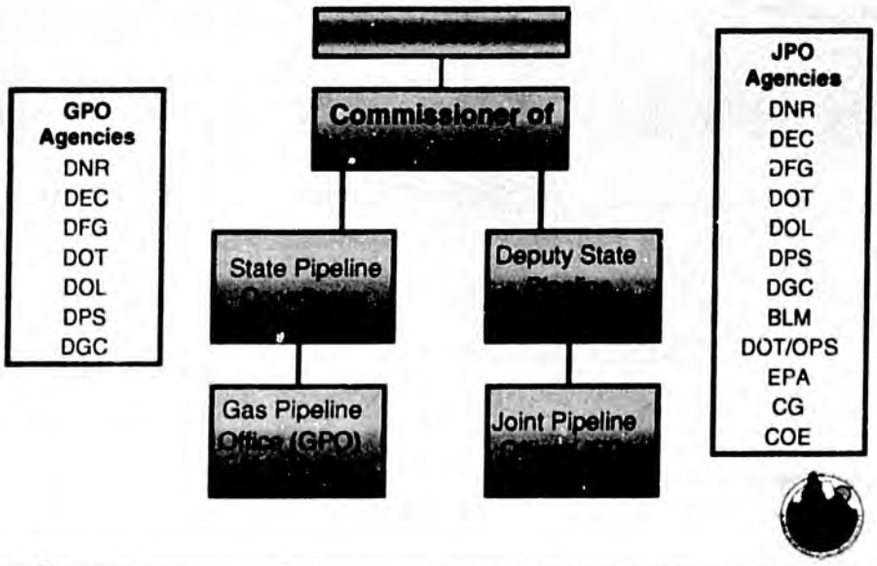
State Pipeline Coordinator is the:

Lead for coordinating state permitting, authorizations, and oversight for gas pipelines
- Work planning
- Scheduling
- Budgeting
- Staffing

Lead for communication and coordination with federal and Canadian agencies related to
- Routing
- Design
- Permitting
- Authorizations
- Construction oversight



State Pipeline Coordinator's Office (SPCO)



FY02 Scope of Work

- Prepare to receive an application
- Work with proponents
- Help create and implement State policy
- Process an application

Questions?



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ADMINISTRATIVE ORDER NO. 187

I, Tony Knowles, Governor of the State of Alaska, under the authority of art. III, secs. 1 and 24, of the Alaska Constitution and AS 44.17.060, name the commissioner of the Department of Natural Resources, through the commissioner's designee, the state pipeline coordinator, as the coordinator of state permits, authorizations, and oversight of pipelines designed to transport natural gas from the Alaska North Slope to market ("Gas Pipelines"). This Order covers the permitting, authorization, and oversight activities of Gas Pipelines by the Departments of Natural Resources, Environmental Conservation, Fish and Game, Transportation and Public Facilities, Labor and Workforce Development, Public Safety, and by the Division of Governmental Coordination ("Designated Agencies"). This Order may be amended to cover the permitting, authorization, and oversight activities of other agencies in the future as necessary and directed by future administrative orders of the Governor. This Order outlines the processes and responsibilities of the Designated Agencies with regard to state permits, authorizations, and oversight related to the preconstruction and construction of Gas Pipelines.

Nothing in this Order affects the responsibilities of state agencies that do not involve permits, authorizations, and oversight of Gas Pipelines, including advocacy by the Department of Law before the Federal Energy Regulatory Commission, or the development of fiscal terms by the Department of Revenue under AS 43.82.

Nothing in this Order re-assigns the responsibility of coordinating Alaska Coastal Management Program consistency reviews under AS 44.19.145 and 6 AAC 50 away from the Division of Governmental Coordination, Office of Management and Budget.

FINDINGS

1. It is in the best interest of the people of Alaska and the nation that Alaska's North Slope natural gas be expeditiously transported to market in a manner that makes the maximum contribution to the development and standard of living of the residents of our state. It is in the best interest of the people of Alaska and the nation that Gas Pipelines be designed and constructed in a safe and environmentally sound manner.

2. It is desirable that the State of Alaska have a unified voice representing its interests in dealings with Canadian and federal agencies, gas owners, pipeline companies, and contractors related to permitting, authorization, and oversight of Gas Pipelines. It is also desirable that the state have a single point of contact for permits, authorizations, and oversight of Gas Pipelines to ensure coordination among state, federal, and international authorizing agencies and, if appropriate, to develop substantially similar terms and conditions in pipeline documents.

3. Permitting, authorization, and oversight of Gas Pipelines involves many state agencies. A coordinated state approval and oversight process for Gas Pipelines that provides for internal alignment and dispute resolution is necessary. Internal alignment fosters efficiency in state permitting, approval, and oversight functions.

4. It is in the best interest of the people of Alaska to utilize existing government structures and processes to the maximum extent possible, optimize state pipeline expertise and performance, and minimize impacts to ongoing functions of government. The State Pipeline Coordinator's Office in the Department of Natural Resources (SPCO) is the appropriate lead and single point of contact for the permitting, authorization, and oversight of proposals for Gas Pipelines.

ORDER

To further these findings, I, Tony Knowles, Governor of the State of Alaska, order and declare the following:

1. A Gas Pipelines Cabinet is established, comprised of the commissioners of the Departments of Natural Resources, Environmental Conservation, Fish and Game, Revenue, Transportation and Public Facilities, Labor and Workforce Development, and Community and Economic Development; the director of the Division of Governmental Coordination; the Governor's Office Washington, D.C. Director; and the Attorney General. The commissioner of the Department of Natural Resources will chair the Gas Pipelines Cabinet.

2. The commissioner of the Department of Natural Resources, through the state pipeline coordinator (SPC), is the lead official for state communication and coordination with appropriate federal and Canadian agencies related to permitting, authorization, and oversight of Gas Pipelines, including routing, design, and construction.

3. The SPC is the lead official for coordinating state permitting, authorization, and oversight by Designated Agencies related to routing, design, and construction of Gas Pipelines. The SPC shall establish and maintain a Gas Pipelines Group within the SPCO to coordinate actions by Designated Agencies related to Gas Pipelines.

4. Each Designated Agency shall appoint a liaison officer who will report directly to the head of the Designated Agency, be assigned to the Gas Pipelines Group, and be located in the Gas Pipelines Group offices established by the SPC. Liaison officers shall serve as a single point of contact representing their Designated Agencies in matters relating to permitting, authorization, and oversight of Gas Pipelines during the preconstruction and construction phases. To the maximum extent consistent with applicable law, Designated Agencies shall delegate signatory authority to their liaison officers for issuance of permits and authorizations during preconstruction and construction phases.

5. Liaison officers shall be available to manage and perform work necessary to process permits and authorizations for Gas Pipelines by their Designated Agency; assist as necessary with permits and authorizations by other Designated Agencies; manage and perform work necessary to oversee construction of Gas Pipelines; and provide other necessary technical assistance to the SPC in their areas of expertise.

6. Liaison officers shall provide annual work plans for accomplishing the tasks outlined in paragraph 5 of this Order to the SPC for approval. The work plans shall include schedules, budgets, and staffing plans for permitting, authorization, and oversight work. Liaison officers shall monitor progress against their work plans and provide periodic reports to the SPC.

7. Staff hired by individual Designated Agencies for the Gas Pipelines Group are under the supervision of the liaison officer for the Designated Agency. Staff providing support from a Designated Agency's regional or central office will continue to work for their supervisor in the Designated Agency.

8. Liaison officers shall manage their Designated Agency's administrative functions that are directly related to their agency's participation in the Gas Pipelines Group, including maintaining agency files. Each Designated Agency shall keep a full set of files at the office of the Gas Pipelines Group on all aspects of its activities related to Gas Pipelines.

9. Liaison officers shall provide copies of all applications and requests for permits and authorizations related to preconstruction and construction of Gas Pipelines to the SPC. Each liaison officer shall coordinate with the SPC public notices and other legally required public hearing processes related to their agency's activities. All permits and authorizations issued by Designated Agencies related to Gas Pipelines preconstruction and construction activities shall be processed in the Gas Pipelines Group. Liaison officers shall provide copies of proposed permits and authorizations to the SPC for review and comment, and shall provide copies of permits and authorizations issued.

10. Each liaison officer shall, to the extent allowed by law and whenever feasible, consult with the SPC and consider the SPC's advice before taking enforcement actions by the Designated Agencies related to Gas Pipelines preconstruction and construction. This provision does not limit Designated Agencies' enforcement authorities or the exercise of those authorities.

11. The SPC shall establish preconstruction and construction field teams that the SPC determines, after consultation with affected agencies, are necessary for data gathering and oversight. Such teams may be composed of staff from a number of Designated Agencies and other state agencies. Responsibilities and authorities of affected state agencies may, consistent with law and after consultation with those agencies, be delegated to team members regardless of their agency affiliation.

12. Between the effective date of this Order and the date of execution of a reimbursement memorandum between the SPC and a Gas Pipelines sponsor, all Designated Agency funding requests associated with Gas Pipelines activities will be handled through the normal budget supplement and increment process coordinated by the Department of Natural Resources.

13. In order to develop a consolidated budget request, all Designated Agencies shall prepare and submit to the SPC an annual budget request for all appropriations, including costs reimbursed under AS 38.35.140(b) and permitting fees identified in statute or regulation, associated with Gas Pipelines projects. After review and approval by the SPC, the budget requests will be consolidated and submitted by the Department of Natural Resources through the budget review process. Gas Pipelines work by Designated Agencies may not be budgeted in the Executive Budget submitted to the legislature except through this process. Upon approval of the budget, and appropriation by the legislature, the SPC shall negotiate reimbursable services agreements with Designated Agencies to cover the approved costs associated with Gas Pipelines preconstruction and construction activities and shall ensure that reimbursement is secured promptly for costs incurred under approved appropriations.

14. If a Designated Agency requires additional staff position(s) to carry out its responsibilities, the agency shall, with the concurrence of the SPC as to appropriation, appoint additional staff.

15. In the event of a dispute between Designated Agencies regarding a matter covered under this Order, including matters involving annual appropriation requests, each affected liaison officer and the SPC will resolve the dispute to the maximum extent possible. If the dispute cannot be resolved between each affected liaison officer and the SPC, then the matter will be resolved by the affected agency heads and the commissioner of the Department of Natural Resources. If the dispute cannot be resolved by the affected agency heads and the commissioner of the Department of Natural Resources, then the matter will be resolved by the governor, after considering any recommendations of the Gas Pipelines Cabinet.

    Unless contrary to any dispute resolution process in statute or regulation, in the event of a dispute between Designated Agencies involving a matter subject to the Designated Agencies' statutory or regulatory authority, each affected liaison officer and the SPC will resolve the dispute to the maximum extent possible. If the dispute cannot be resolved by the affected liaison officer and the SPC, then the matter will be resolved by the affected agency heads. If the dispute cannot be resolved by the agency heads, then the matter may be considered by the governor, after consideration of any recommendations of the Gas Pipelines Cabinet. The decision of the head of the Designated Agency responsible for administering the statute or regulation in question is final. In all such disputes, the head of the Designated Agency responsible for administering the statute or regulation shall seek and consider the views of other affected agency heads before making a decision.

16. The Office of the Governor, Division of Governmental Coordination (DGC), shall coordinate the Alaska Coastal Management Program consistency review of activities related to Gas Pipelines as provided under AS 44.19.145 and 6 AAC 50. To the maximum extent allowed by law, the SPC and DGC shall coordinate their respective Gas Pipelines activities.

17. Consistent with AS 44.23.020, the Attorney General, as legal advisor to the State of Alaska, shall provide legal services to the SPCO Gas Pipelines Group and all Designated Agencies within the SPCO Gas Pipelines Group.

18. This Order is for administrative purposes only. It does not create any third party rights nor modify the statutory and regulatory authorities of Designated Agencies.

19. The SPC will submit to the Governor and the Gas Pipelines Cabinet periodic progress reports that summarize goals and objectives and accomplishments against those goals and objectives.

To the extent that this Administrative Order is inconsistent with Administrative Order No. 134, this Order supersedes those portions of that order. This Order revokes Administrative Order No. 70.

This Order takes effect immediately.

DATED at Juneau, Alaska, this 3th day of January, 2001.

Tony Knowles
Governor

4/10/02
JNG P

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SENATE BILL NO. 360

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SECOND LEGISLATURE - SECOND SESSION

BY THE SENATE RESOURCES COMMITTEE

Introduced: 4/10/02
Referred:

A BILL

FOR AN ACT ENTITLED

"An Act establishing additional requirements for the consideration of applications under the Right-of-Way Leasing Act for an Alaska North Slope natural gas project, authorizing expeditious priority treatment of all applications under that Act and under other relevant state laws for issuance of a right-of-way lease for that project, authorizing the commissioner of natural resources to act to modify the terms of certain state oil and gas leases related to the project and to act, with legislative approval, to waive, reduce, or defer the collection of royalties due the state, and authorizing the commissioner of revenue to act, with legislative approval, to waive, reduce, or defer the levy and collection of taxes by the state and municipalities under the oil and gas exploration, production, and pipeline transportation property tax related to the project, authorizing the Alaska Railroad Corporation to provide financing for the acquisition, construction, improvement, maintenance, equipping, operation, or expansion of the project and

related facilities for the transportation of natural gas within and outside the state by others and the corporation's issuance of its bonds to finance the project and facilities, and limiting consideration of judicial challenges to decisions made with respect to that project under this Act; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** The uncodified law of the State of Alaska is amended by adding a new section to read:

SHORT TITLE. This Act may be cited as the Alaska Natural Gas Project Act.

*** Sec. 2.** The uncodified law of the State of Alaska is amended by adding a new section to read:

LEGISLATIVE FINDINGS WITH RESPECT TO BILL SECTIONS AMENDING THE RIGHT-OF-WAY LEASING ACT (AS 38.35) AND RELATED PROVISIONS. The legislature finds that

(1) expediting the development, production, and transportation of northern Alaska natural gas is a matter of statewide significance because of its vital importance to the state's economy;

(2) the best interests of the state would be served by a North Slope natural gas pipeline project following a route that parallels the Trans Alaska Pipeline System and the Alaska Highway to the Canadian border or a project from the North Slope to tidewater in southcentral Alaska;

(3) in accordance with 15 U.S.C. 719 - 729o (the Alaska Natural Gas Transportation Act of 1976), in a series of actions and decisions that recognize the critical importance of the project, the President and the Congress have approved and authorized completion of a North Slope natural gas pipeline project;

(4) under a portion of pending federal legislation referred to as the "Alaska Natural Gas Pipeline Project of 2002," another North Slope natural gas project may be approved and authorized;

(5) under the Alaska Natural Gas Transportation Act of 1976, Yukon Pacific Corporation has received a presidential waiver to export Alaska natural gas, and holds several

permits, authorizations, and licenses to construct and operate a North Slope natural gas project to tidewater;

(6) other entities have expressed interest in constructing various North Slope natural gas projects;

(7) the maximum benefit for Alaskans from the commercialization of northern Alaska natural gas lies in market exposure for the gas, opportunities for in-state use of the gas, participation by Alaskans in construction, maintenance, and operation of the project, and competition in the exploration, development, and production of additional reserves of northern Alaska natural gas;

(8) 15 U.S.C. 719k(b) (section 13(b), Alaska Natural Gas Transportation Act of 1976) provides that the "State of Alaska is authorized to ship its gas on the approved transportation system for use within Alaska . . . and . . . to withdraw such gas from the interstate market for use within Alaska; the Federal Power Commission shall issue all authorizations necessary to effectuate such shipment and withdrawal subject to review by the Commission only of the justness and reasonableness of the rate charged for such transportation";

(9) the President's decision in support of his choice of the route approved under the Alaska Natural Gas Transportation Act of 1976 recognized that Alaska gas could "supply the energy base required for long-term economic development" within the state and it could supply natural gas to communities within the state along the route and to other communities through local distribution lines;

(10) it is vital for the continued exploration and development of natural gas resources in northern Alaska that oil and gas companies that do not have an ownership interest in the project have access to it on a fair and reasonable basis and have the ability to seek the pipeline's expansion when economically and technically feasible;

(11) it is vital to the economic development of the state that Alaskans and Alaska businesses have access to gas from a North Slope natural gas pipeline project;

(12) it has the constitutional responsibility set out in art. VIII, sec. 2, Constitution of the State of Alaska, to provide for the utilization, development, and conservation of the state's natural resources for the maximum benefit of the people; and

(13) because of the magnitude and complexity of the development of a

project, issuance of a right-of-way lease under the Alaska Right-of-Way Leasing Act and of permits, certificates, authorizations, and similar actions to be taken by state agencies in connection with the development of a project implicates unique legal and administrative considerations.

*** Sec. 3.** The uncodified law of the State of Alaska is amended by adding a new section to read:

FINDINGS, INTENT, AND PURPOSE RELATING TO AMENDMENTS TO THE ALASKA RAILROAD CORPORATION ACT (AS 42.40). (a) The Alaska State Legislature finds that

(1) the Alaska Railroad Corporation is uniquely suited to serve essential functions of the state by providing financing for an Alaska North Slope natural gas project;

(2) providing financing for the project furthers the purposes of both the state and the Alaska Railroad Corporation by assuring that the state's northern Alaska natural gas resources will be transported to their appropriate markets, thus creating revenue for the Alaska Railroad Corporation and for the state and providing employment opportunities for residents of the state;

(3) the project also will enhance and improve the state's ability to develop and transport other natural resources of the state, including oil and gas resources located off the North Slope of this state; and

(4) these results are essential purposes of the state, and the achievement of these purposes is critical to the health and welfare of the state.

(b) A purpose of the amendments made by secs. 6 - 9 and 13 of this Act is to clarify the statutory functions and powers of the Alaska Railroad Corporation by expressly including the power to provide financing for transportation facilities as described in this Act.

(c) It is the intent of the legislature that

(1) secs. 6 - 9 and 13 of this Act be construed broadly to permit the Alaska Railroad Corporation the greatest flexibility to accomplish the purpose described in (b) of this section within the limitations set out in this Act; and

(2) other provisions of AS 42.40 in existence before the enactment of this Act be similarly construed to complement the provisions of this Act.

*** Sec. 4.** AS 38.05.180 is amended by adding a new subsection to read:

(ee) In conjunction with the development and construction of an Alaska North Slope natural gas project, as defined by AS 38.35.259, that requires the grant of a right-of-way lease under AS 38.35 for which the project applicant has complied with AS 38.35.240 and obtained all certificates described in that section, the commissioner may

(1) with the consent of the lessee,

(A) modify any provision of an oil and gas lease entered into under this section, except a provision described in (B) of this paragraph, that impedes development of the project; and

(B) waive, reduce, or defer the payment of all or any portion of the royalty due the state under this chapter; a waiver, reduction, or deferral of the royalty due made by the commissioner under this subparagraph is not effective unless approved by the legislature; the legislature may approve a waiver, reduction, or deferral of royalty under this subparagraph only by enacting legislation;

(2) take an action described in (1)(B) of this subsection only if

(A) the commissioner has considered whether other jurisdictions in which the project will be located have granted financial incentives;

(B) the project applicant, or a lessee that has contracted with the applicant to ship natural gas through the project, shows, by clear and convincing evidence, that construction and operation of the project would not otherwise be economically feasible; and

(C) the commissioner and the project applicant have entered into r. agreement to begin construction of the project by a date certain.

*** Sec. 5.** AS 38.35 is amended by adding new sections to read:

Sec. 38.35.235. Purpose of AS 38.35.235 - 38.35.259. It is the purpose of AS 38.35.235 - 38.35.259

(1) to expedite the approval, construction, and operation of a project while ensuring that the maximum benefits consistent with the Constitutions of the United States and Alaska are achieved for the people of the state;

(2) to ensure access to the project by oil and gas companies that do not have an ownership interest in the project on an equal and nondiscriminatory basis, and to promote competition in the exploration, development, and production of northern Alaska natural gas;

(3) to ensure access to state royalty gas in the project for Alaskans and Alaska businesses; and

(4) to ensure employment of Alaskans and the use of Alaska firms in the construction and operation of the project.

Sec. 38.35.240. Applicability to Alaska North Slope natural gas project. (a) The provisions of AS 38.35.235 - 38.35.259 apply to an applicant for a right-of-way lease under this chapter for an Alaska North Slope natural gas project that submits a written plan and study, as appropriate, and obtains the certificates described in (b) - (d) of this section.

(b) Based upon the applicant's written plan, if the commissioner of labor and workforce development is satisfied that the plan fulfills the requirements of this subsection and makes an appropriate finding, the commissioner may certify that

(1) consistent with law, the applicant will use the applicant's best efforts to train and employ state residents and, whenever feasible, will contract with firms in this state for the construction and operation of the project; and

(2) the applicant's plan maximizes the opportunities for training and employment of state residents and for the use of Alaska firms in the state for the construction and operation of the project consistent with the Constitutions of the United States and Alaska and AS 38.35.235(4); the commissioner may not make a finding under this paragraph unless the commissioner conducts at least one public hearing on the plan.

(c) Based upon the applicant's written plan and study, if the Regulatory Commission of Alaska is satisfied that the plan and study fulfill the requirements of this subsection and makes an appropriate finding, the commission may certify that the applicant

(1) has completed a study examining in-state demand for northern Alaska natural gas and, with the completed study, has submitted a plan demonstrating

that the applicant's plan will maximize the opportunities for access to state royalty gas transported in the project to meet the reasonably projected in-state demand identified in the study and is consistent with AS 38.35.235(3);

(2) has completed a study of the potential supply of northern Alaska gas, including known and discovered reserves and undiscovered resources, and the applicant has submitted a plan demonstrating how the applicant's plan and design of the project will maximize the opportunities for access to initial and expansion capacity on the project consistent with AS 38.35.235(2); the commission may not make a finding under this paragraph unless the commission conducts at least one public hearing on the study and plan; and

(3) agrees to complete for review by the commission updated studies and plans consistent with (1) and (2) of this subsection at a date that is 10 years after the construction commencement date of the project.

(d) Based upon the application submitted under this chapter, if the commissioner is satisfied that the application meets all other requirements of law and fulfills the requirements of this subsection and makes an appropriate finding, the commissioner may certify that the applicant agrees to provisions of the lease stipulating that the applicant will

(1) provide access to the project to the state or its designee to ship the state's royalty gas for use within the state; and

(2) use the applicant's best efforts to seek and obtain

(A) all authorizations necessary to carry out the shipment and withdrawal described in 15 U.S.C. 719k(b) (section 13(b), Alaska Natural Gas Transportation Act of 1976) or other appropriate federal law from the Federal Energy Regulatory Commission or any other applicable governmental agency to ensure that access; and

(B) authorization from the Federal Energy Regulatory Commission or any other applicable governmental agency to expand the project if the Regulatory Commission of Alaska, upon application by an entity seeking to ship Alaska natural gas through the project, determines that expansion is in the best interests of the state and is in accordance with this

section and finds that

(i) the rates for expansion of the natural gas transportation service will ensure the recovery, on an incremental or rolled-in basis, of the costs of the facilities necessary for expansion, including a reasonable rate of return on the applicant's investment;

(ii) the rates do not require the then-existing shippers of North Slope natural gas in the project to subsidize the use of the project by expansion shippers;

(iii) facilities necessary for expansion will not adversely affect the operation of the project or diminish the contract rights of then-existing shippers to previously certificated capacity;

(iv) all necessary environmental reviews have been completed; and

(v) the expansion is required by the present and future public convenience.

(e) Each authority that may issue a certificate under (b) or (c) of this section shall act within 90 days after receiving a request for a certificate. The commissioner shall act under (d) of this section not later than 90 days after the commissioner receives from the applicant the stipulations described in that subsection.

Sec. 38.35.245. Treatment of Alaska North Slope natural gas project lease application by commissioner. In the commissioner's consideration of an application under this chapter for a lease for the Alaska North Slope natural gas project, when the applicant has complied with requirements of AS 38.35.240 and obtained all certificates described in that section, the commissioner may limit the scope of review, analysis, and finding for the applicant's proposed lease application under this chapter to a particular phase of the project if, in the judgment of the commissioner, the project is capable of proceeding in discrete phases and

(1) the uses and activities involving the project on the land for which the approval is to be granted are part of that discrete phase;

(2) before the next phase of the project may proceed, the commissioner gives public notice and opportunity for comment about that phase, unless the use or

activity to be approved is subject to a consistency determination under AS 46.40 and public notice and the opportunity to comment are provided under AS 46.40.096(c);

(3) the commissioner's approval is required before the next phase of the project may proceed; and

(4) the commissioner sets out the reasons for proceeding on the application in discrete phases.

Sec. 38.35.250. Expeditious priority treatment by state officials and agencies in support of development and construction of Alaska North Slope natural gas project under this chapter. (a) In the development and construction of an Alaska North Slope natural gas project that requires the grant of a right-of-way lease under this chapter for which the project applicant has complied with AS 38.35.240 and obtained all certificates described in that section, every state official and agency shall give full cooperation to the commissioner, or to any official to whom delegation of the authority of the commissioner is made by or under law,

(1) by assembling and furnishing all requested information;

(2) consistent with the provisions of the law administered by the official or agency, by issuing or granting necessary permits, certificates, authorizations, and similar actions required to be taken at the earliest practicable date, on an expedited basis and, notwithstanding any other provision of law, with precedence over any like matter pending before the official or agency; and

(3) consistent with the provisions of the law administered by the official or agency, with respect to any previously issued or granted permit, certificate, authorization, or similar action as to which the official or agency may exercise discretion, by adding to, amending, or abrogating any term or condition as necessary to further the purposes set out in AS 38.35.235 except

(A) changing or altering the basic nature or general route of an Alaska North Slope natural gas project to which the federal government has agreed; or

(B) otherwise significantly preventing or impairing the expeditious construction and operation of an Alaska North Slope natural gas project.

Sec. 38.35.255. Waiver of law. If the governor finds that any provision of law applicable to actions to be undertaken by a state agency or official with respect to any authorization necessary for a right-of-way lease or any other authorization necessary for a project under this chapter or any action to be taken in the exercise of rights conferred by that lease constitutes an obstacle to the expeditious construction and initial operation of an Alaska North Slope natural gas project for which the project applicant has complied with AS 38.35.240 and obtained all certificates described in that section, the governor may submit a measure for the legislature's consideration to provide by law for the waiver of the provision.

Sec. 38.35.257. Judicial review. Notwithstanding AS 38.35.200 and notwithstanding any other provision of law, with respect to a decision made or action taken bearing upon the development, construction, and operation of an Alaska North Slope natural gas project for which the project applicant has complied with AS 38.35.240 and obtained all certificates described in that section, a person may seek judicial review of a decision of the commissioner under AS 38.35.100 or AS 38.35.235 - 38.35.259 or of any agency or employee relating to the project only on the grounds provided in AS 38.35.200(b). The claim for judicial review may be brought only within 60 days after the making of the decision or taking of the action.

Sec. 38.35.259. Definitions. In AS 38.35.235 - 38.35.259,

(1) "Alaska North Slope natural gas project" or "project" means a North Slope natural gas pipeline, as defined in AS 38.35.120, and related facilities, including extraction and petrochemical plants, liquefaction plants, regasification plants, and conditioning plants, and the expansion of that pipeline and those related facilities, constructed to transport northern Alaska natural gas following a route that parallels the Trans Alaska Pipeline System and the Alaska Highway to the Canadian border or that initially parallels the Trans Alaska Pipeline System and then turns south to tidewater in southcentral Alaska;

(2) "northern Alaska natural gas" means natural gas from the area of the state lying north of 64 degrees North latitude.

*** Sec. 6.** AS 42.40.250 is amended by adding a new paragraph to read:

(31) provide financing for the acquisition, construction, improvement,

maintenance, equipping, operation, and expansion of an Alaska North Slope natural gas project, as that term is defined in AS 38.35.259, within and outside the state without regard to whether the project or facilities are or will be owned in whole or in part by the corporation or located on land owned by the corporation.

*** Sec. 7.** AS 42.40 is amended by adding a new section to read:

Sec. 42.40.605. Public purpose of bonds. Bonds of the corporation issued to finance the project and related facilities described in AS 42.40.250(31) are issued by a public corporation and an instrumentality of the state for an essential public and governmental purpose.

*** Sec. 8.** AS 42.40.630 is amended by adding a new subsection to read:

(b) Before issuing bonds to provide the financing described in AS 42.40.250(31) for a facility related to the Alaska North Slope natural gas project to be owned in whole or in part by an entity other than the corporation, the corporation shall enter into a contract, lease, or other form of agreement that will, in the judgment of the corporation, provide sufficient consideration to

(1) pay the principal of and interest on the bonds as they become due;

(2) create and maintain the reserves for the payments that the corporation considers necessary or desirable; and

(3) pay all costs necessary to service or additionally secure the bonds, including trustee's fees and bond insurance premiums, unless these costs are to be paid by a party other than the corporation.

*** Sec. 9.** AS 42.40 is amended by adding a new section to read:

Sec. 42.40.695. Alaska North Slope natural gas project bonds. (a) In conjunction with the development and construction of an Alaska North Slope natural gas project that require the grant of a right-of-way lease under AS 38.35 for which the project applicant has complied with AS 38.35.240 and obtained all certificates described in that section, and subject to the requirements of AS 42.40.630(b), the corporation is authorized to issue bonds under the power granted to it in this chapter to finance the construction of a natural gas pipeline and related facilities for the transportation of natural gas recovered from the North Slope of this state.

(b) The maximum principal amount of bonds that the corporation may issue

under this section is $18,000,000,000.

(c) The corporation

(1) shall negotiate with an applicant as the corporation considers appropriate and shall enter into agreements with the applicant to provide revenue sufficient to accomplish the purposes described in AS 42.40.630; and

(2) may issue the bonds in a single issuance or in several issuances, without limitation as to number of issuances or timing, and as the corporation determines best furthers the purpose of financing the project and related facilities.

(d) The proceeds of the bonds described in this section shall be used only for an Alaska North Slope natural gas project and related facilities that are owned by one or more entities other than the corporation.

(e) In this section, "Alaska North Slope natural gas project" has the meaning given in AS 38.35.259.

* **Sec. 10.** AS 43.56 is amended by adding a new section to read:

Sec. 43.56.185. Commissioner may waive, reduce, or defer application of certain tax laws with legislative approval. (a) In conjunction with the development and construction of an Alaska North Slope natural gas project, as defined by AS 38.35.259, that requires the grant of a right-of-way lease under AS 38.35 for which the project applicant has complied with AS 38.35.240 and obtained all certificates described in that section, the commissioner may waive, reduce, or defer the payment of all or any portion of the tax levied by the state or a municipality of the state under this chapter. The commissioner may take an action described in this subsection only if

(1) the commissioner has consulted with any affected municipality, has considered and prepared a report on the socioeconomic effects of the project on any affected municipality, and has considered whether other jurisdictions in which the project will be located have granted financial incentives;

(2) the project applicant shows, by clear and convincing evidence, that construction and operation of the project would not otherwise be economically feasible; and

(3) the commissioner and the project applicant have entered into an agreement to begin construction of the project by a date certain.

(b) A waiver, reduction, or deferral of tax made by the commissioner under (a) of this section is not effective until approved by the legislature. The legislature may approve a waiver, reduction, or deferral of tax under this section only by enacting legislation.

*** Sec. 11.** AS 46.40.094 is amended by adding a new subsection to read:

(d) Notwithstanding any other provision of this section, for a natural gas pipeline project from the Alaska North Slope following a route that parallels the Trans Alaska Pipeline System and the Alaska Highway to the Canadian border or a route that runs south to Alaska tidewater for which the project applicant has complied with AS 38.35.240 and obtained all certificates described in that section, any agency responsible for the consistency determination with respect to proposed uses or activities involved in the project may, in its discretion, conduct the review and make the consistency determination in separate phases in a manner that promotes review of proposed uses and activities based upon the project's design, construction sequence, and schedule.

*** Sec. 12.** The uncodified law of the State of Alaska is amended by adding a new section to read:

LIMITATION OF CERTAIN ACTIONS. A legal proceeding may not be initiated to challenge the constitutionality of sec. 2 of this Act or the constitutionality of AS 38.35.235 - 38.35.259, added by sec. 5 of this Act, more than 60 days after the effective date of this Act.

*** Sec. 13.** The uncodified law of the State of Alaska is amended by adding a new section to read:

LEGISLATIVE AUTHORIZATION AND APPROVAL. AS 42.40.695, added by sec. 9 of this Act, and this section constitute the approval required by AS 42.40.285 for the issuance of the bonds described in AS 42.40.695.

*** Sec. 14.** This Act takes effect immediately under AS 01.10.070(c).

22-LS0764\C

HOUSE CONCURRENT RESOLUTION NO. 8

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SECOND LEGISLATURE - FIRST SESSION

BY REPRESENTATIVES WHITAKER, Harris

Introduced: 3/16/01
Referred: House Special Committee on Oil and Gas, Resources

A RESOLUTION

Expressing the legislature's opposition to the proposed "northern" or "over-the-top" route for a natural gas pipeline to transport North Slope natural gas reserves to the domestic North American market, and expressing the legislature's support of commercialization of North Slope natural gas for the maximum benefit of the people of the state.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS 35 trillion cubic feet of known natural gas reserves are acknowledged to be adherent to oil and gas leases on the North Slope of Alaska, and, additionally, realistic estimates of total recoverable gas from the reserves exceed 100 trillion cubic feet; and

WHEREAS demand for new sources of natural gas supply in North American and Asian markets places Alaska's North Slope natural gas in the unique position of being attractive to both markets; and

WHEREAS improved economics, technological advances, and the possibility of public financing of a natural gas pipeline have removed previously perceived barriers to the commercialization of Alaska's North Slope natural gas; and

WHEREAS oil and gas leaseholders on Alaska's North Slope continue to develop competing gas projects elsewhere in the world while Alaska gas remains warehoused; and

WHEREAS art. VIII, sec. 1, Constitution of the State of Alaska, provides that it is the policy of the state to encourage the settlement of its land and the development of its resources by making them available for maximum use consistent with the public interest; and

WHEREAS art. VIII, sec. 2, Constitution of the State of Alaska, requires the legislature to provide for the utilization, development, and conservation of all natural resources belonging to the state, including land and waters, for the maximum benefit of its people; and

WHEREAS it is widely recognized that maximum benefit to Alaska from the commercialization of North Slope natural gas lies in maximum market exposure for Alaska North Slope gas reserves, maximum opportunities for in-state use of the natural gas, maximum opportunities for participation by Alaskans in construction, maintenance, and operation of the gas line transportation project, and maximum revenue to the state from the development, transport, and sale of Alaska North Slope gas reserves; and

WHEREAS the "northern" or "over-the-top" route for the proposed pipeline, running east from the North Slope to Canada's Mackenzie River Valley, then south through that valley to link to existing pipeline networks, under consideration by the North American Gas Pipeline Group, offers none of these benefits;

BE IT RESOLVED that the Alaska State Legislature supports the commercialization of Alaska North Slope natural gas for the maximum benefit of the people of the state; and be it

FURTHER RESOLVED that the legislature will exercise every power within its constitutionally required authority to guarantee commercialization of Alaska North Slope natural gas for the maximum benefit of the people of the state; and be it

FURTHER RESOLVED that the legislature opposes construction of a "northern" or "over-the-top" route for a natural gas pipeline; and be it

FURTHER RESOLVED that the legislature will exercise every power within its authority to prevent the routing of a North Slope natural gas pipeline that bypasses Alaska.

HOUSE BILL NO. 9

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SECOND LEGISLATURE - FIRST SESSION

BY REPRESENTATIVE GREEN

Introduced: 1/8/01
Referred: House Special Committee on Oil and Gas, Resources

A BILL

FOR AN ACT ENTITLED

"An Act amending the standards applicable to determining whether a proposed new investment constitutes a qualified project for purposes of the Alaska Stranded Gas Development Act; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** AS 43.82.100 is amended to read:

Sec. 43.82.100. Qualified project. Based on information available to the commissioner, the commissioner may determine that a proposal for new investment is a qualified project under this chapter only if the project

(1) [IS A PROJECT FOR THE EXPORT OF LIQUEFIED NATURAL GAS;

(2)] would produce at least 500,000,000,000 cubic feet of stranded gas within 20 years from the commencement of commercial operations; and

(2) [(3)] is capable, subject to applicable commercial regulation and technical and economic considerations, of making gas available to meet the reasonably

foreseeable demand in this state for gas within the economic proximity of the project.

*** Sec. 2.** This Act takes effect immediately under AS 01.10.070(c).

HOUSE BILL NO. 21

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SECOND LEGISLATURE - FIRST SESSION

BY REPRESENTATIVES PORTER AND MULDER, Dyson

Introduced: 1/8/01
Referred: House Special Committee on Oil and Gas, Resources

A BILL

FOR AN ACT ENTITLED

"An Act relating to the construction of an overland natural gas pipeline to transport natural gas from North Slope reserves to North American markets."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** The uncodified law of the State of Alaska is amended by adding a new section to read:

LEGISLATIVE FINDINGS. The legislature finds that

(1) known natural gas resources on the oil and gas leases of the North Slope of Alaska, amounting to 35 trillion cubic feet (Tcf) that are ready for production, together with estimates of total recovery from gas fields that may ultimately exceed an estimated 100 Tcf, confirm Alaska as a principal source of energy to meet North American market demands for cleaner, more efficient energy in this new century;

(2) an improved investment climate, technological and engineering improvements that have reduced the cost of construction and operation of a natural gas transportation system under arctic and subarctic conditions, and strong demand for the gas in

the North American market have significantly improved prospects for development of these gas reserves and delivery of the gas to the population and industrial centers of Canada and the United States;

(3) the gas reserves of Alaska's North Slope are so large that, without foreclosing consideration of projects involving gas-to-liquids and liquefied natural gas technologies, the projected demands of the North American market will require completion of an overland gas pipeline between the North Slope and the existing natural gas pipeline network in north central Alberta;

(4) producers have identified two major routes--a "northern" route running east from the North Slope to Canada's Mackenzie River Valley, then south through that valley to link to the pipeline network, and a "southern" route parallel to the trans Alaska oil pipeline to the state's Interior, branching to parallel the Alaska Highway through the Yukon Territory and northern British Columbia to link to the pipeline network--as the only natural gas pipeline projects worthy of full consideration;

(5) it is in the best interest of the State of Alaska that the natural gas pipeline be constructed along the "southern" route, for construction along this route will

(A) provide the benefit of a less expensive, cleaner energy source to the Interior of the state and provide the opportunity for additional gas commercialization throughout the state;

(B) have the benefit of transportation access and support infrastructure, following in part a route for which environmental studies have already been developed;

(C) add significant property value to the tax base of the state and its local governments, generating millions of dollars of additional state and local government revenue; and

(D) provide direct short-term construction and long-term operation-related employment opportunities for Alaskans.

HOUSE BILL NO. 38

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SECOND LEGISLATURE - FIRST SESSION

BY THE HOUSE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

Introduced: 1/8/01
Referred: House Special Committee on Oil and Gas, Resources, Finance

A BILL

FOR AN ACT ENTITLED

"An Act amending the application deadline, and the standards applicable to determining whether a proposed new investment constitutes a qualified project, for purposes of the Alaska Stranded Gas Development Act; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** AS 43.82.100 is amended to read:

Sec. 43.82.100. Qualified project. Based on information available to the commissioner, the commissioner may determine that a proposal for new investment is a qualified project under this chapter only if the project

(1) [IS A PROJECT FOR THE EXPORT OF LIQUEFIED NATURAL GAS;

(2)] would produce at least 500,000,000,000 cubic feet of stranded gas within 20 years from the commencement of commercial

operations; and

(2) [(3)] is capable, subject to applicable commercial regulation and technical and economic considerations, of making gas available to meet the reasonably foreseeable demand in this state for gas within the economic proximity of the project.

*** Sec. 2.** AS 43.82.170 is amended to read:

Sec. 43.82.170. Application deadline. The commissioner of revenue or the commissioner of natural resources may not act on an application for a contract submitted under AS 43.82.120 unless the application is received by the Department of Revenue no later than **December 31, 2001** [JUNE 30, 2001].

*** Sec. 3.** This Act takes effect immediately under AS 01.10.070(c).

SENATE BILL NO. 17

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SECOND LEGISLATURE - FIRST SESSION

BY THE SENATE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

Introduced: 1/8/01
Referred: Transportation, Resources, Finance

A BILL

FOR AN ACT ENTITLED

"An Act amending the application deadline, and the standards applicable to determining whether a proposed new investment constitutes a qualified project, for purposes of the Alaska Stranded Gas Development Act; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** AS 43.82.100 is amended to read:

Sec. 43.82.100. Qualified project. Based on information available to the commissioner, the commissioner may determine that a proposal for new investment is a qualified project under this chapter only if the project

(1) [IS A PROJECT FOR THE EXPORT OF LIQUEFIED NATURAL GAS;

(2)] would produce at least 500,000,000,000 cubic feet of stranded gas within 20 years from the commencement of commercial

operations; and

(2) [(3)] is capable, subject to applicable commercial regulation and technical and economic considerations, of making gas available to meet the reasonably foreseeable demand in this state for gas within the economic proximity of the project.

*** Sec. 2.** AS 43.82.170 is amended to read:

Sec. 43.82.170. Application deadline. The commissioner of revenue or the commissioner of natural resources may not act on an application for a contract submitted under AS 43.82.120 unless the application is received by the Department of Revenue no later than **December 31, 2001** [JUNE 30, 2001].

*** Sec. 3.** This Act takes effect immediately under AS 01.10.070(c).

HOUSE BILL NO. 60

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SECOND LEGISLATURE - FIRST SESSION

BY THE HOUSE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

Introduced: 1/16/01
Referred: House Special Committee on Oil and Gas, Resources

A BILL

FOR AN ACT ENTITLED

"An Act relating to the Right-of-Way Leasing Act; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** AS 38.35.020(a) is amended to read:

(a) Rights-of-way on state land including rights-of-way [OVER, UNDER, ALONG, ACROSS, OR UPON THE RIGHT-OF-WAY OF A PUBLIC ROAD OR HIGHWAY OR THE RIGHT-OF-WAY OF A RAILROAD OR OTHER PUBLIC UTILITY, OR] across, upon, over, or under a river or other body of water or land belonging to or administered by the state may be granted by noncompetitive lease by the commissioner for pipeline purposes for the transportation of oil, products, or natural gas under those conditions prescribed by **statute** [LAW] or by [ADMINISTRATIVE] regulation. Except to the extent authorized by an oil and gas lease or unit agreement approved by the state, **a** [NO] person may **not** engage in any construction or operation of any part of an oil, products, or natural gas pipeline, which in whole or in part is or is proposed to be on state land unless that person has obtained from the commissioner a right-of-way lease of the land under this chapter.

* **Sec. 2.** AS 38.35.110 is amended to read:

Sec. 38.35.110. Term of lease. Each lease of state land for pipeline right-of-way purposes must contain a provision that the lease shall run for a specified term of not greater than 30 years, and shall be renewable for additional periods of up to **30** [10] years each, so long as the lessee is in commercial operation and is in full compliance with all state law, including [BUT NOT LIMITED TO] state law pertaining to regulation and taxation of the pipeline facility, and is in compliance will all terms of the lease. In making this determination the commissioner shall take into consideration the cost of the proposed pipeline, its useful life, and the probable financing requirement for the proposed pipeline.

* **Sec. 3.** AS 38.35.140(b) is amended to read:

(b) The lessee shall reimburse the state for all reasonable costs incurred in processing an application filed under AS 38.35.050 and in monitoring the construction**, operation, maintenance, and termination** of the pipeline on the right-of-way.

* **Sec. 4.** AS 38.35.230(9) is amended to read:

(9) "state land" means

(A) "state land" as defined in AS 38.05.965;

(B) public land of the United States selected by the state under **sec. 6** [§ 6] of the Alaska Statehood Act of 1958 (PL 85-508; 72 Stat. 399), as amended, and real property of the United States transferred to the state under **secs. 21, 35, and 45** [§§ 21, 35 and 45] of the Alaska Omnibus Act of 1959 (PL 86-70; 73 Stat. 141), as amended;

(C) any interest owned by the state in land**, if the interest is sufficient to permit the state to lease it under the authority of this chapter**;

* **Sec. 5.** The uncodified law of the State of Alaska is amended by adding a new section to read:

APPLICABILITY. This Act applies to all new right-of-way leases, and amendments and renewals of existing leases, issued under AS 38.35 and entered into on or after the effective date of this Act.

* **Sec. 6.** This Act takes effect immediately under AS 01.10.070(c).

SENATE BILL NO. 32

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SECOND LEGISLATURE - FIRST SESSION

BY THE SENATE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

Introduced: 1/12/01
Referred: Resources, Finance

A BILL

FOR AN ACT ENTITLED

"An Act relating to the Right-of-Way Leasing Act; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** AS 38.35.020(a) is amended to read:

(a) Rights-of-way on state land including rights-of-way [OVER, UNDER, ALONG, ACROSS, OR UPON THE RIGHT-OF-WAY OF A PUBLIC ROAD OR HIGHWAY OR THE RIGHT-OF-WAY OF A RAILROAD OR OTHER PUBLIC UTILITY, OR] across, upon, over, or under a river or other body of water or land belonging to or administered by the state may be granted by noncompetitive lease by the commissioner for pipeline purposes for the transportation of oil, products, or natural gas under those conditions prescribed by **statute** [LAW] or by [ADMINISTRATIVE] regulation. Except to the extent authorized by an oil and gas lease or unit agreement approved by the state, **a** [NO] person may **not** engage in any construction or operation of any part of an oil, products, or natural gas pipeline, which in whole or in part is or is proposed to be on state land unless that person has obtained from the commissioner a right-of-way lease of the land under this chapter.

* **Sec. 2.** AS 38.35.110 is amended to read:

Sec. 38.35.110. Term of lease. Each lease of state land for pipeline right-of-way purposes must contain a provision that the lease shall run for a specified term of not greater than 30 years, and shall be renewable for additional periods of up to **30** [10] years each, so long as the lessee is in commercial operation and is in full compliance with all state law, including [BUT NOT LIMITED TO] state law pertaining to regulation and taxation of the pipeline facility, and is in compliance will all terms of the lease. In making this determination the commissioner shall take into consideration the cost of the proposed pipeline, its useful life, and the probable financing requirement for the proposed pipeline.

* **Sec. 3.** AS 38.35.140(b) is amended to read:

(b) The lessee shall reimburse the state for all reasonable costs incurred in processing an application filed under AS 38.35.050 and in monitoring the construction**, operation, maintenance, and termination** of the pipeline on the right-of-way.

* **Sec. 4.** AS 38.35.230(9) is amended to read:

(9) "state land" means

(A) "state land" as defined in AS 38.05.965;

(B) public land of the United States selected by the state under **sec. 6** [§ 6] of the Alaska Statehood Act of 1958 (PL 85-508; 72 Stat. 399), as amended, and real property of the United States transferred to the state under **secs. 21, 35, and 45** [§§ 21, 35 and 45] of the Alaska Omnibus Act of 1959 (PL 86-70; 73 Stat. 141), as amended;

(C) any interest owned by the state in land**, if the interest is sufficient to permit the state to lease it under the authority of this chapter**;

* **Sec. 5.** The uncodified law of the State of Alaska is amended by adding a new section to read:

APPLICABILITY. This Act applies to all new right-of-way leases, and amendments and renewals of existing leases, issued under AS 38.35 and entered into on or after the effective date of this Act.

* **Sec. 6.** This Act takes effect immediately under AS 01.10.070(c).

22-LS0308\L

SENATE BILL NO. 76

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SECOND LEGISLATURE - FIRST SESSION

BY SENATORS THERRIAULT, Wilken, Kelly, Green

Introduced: 2/7/01
Referred: Resources

A BILL

FOR AN ACT ENTITLED

"An Act amending the permissible period of renewal of a lease entered into under the Alaska Right-of-Way Leasing Act, and providing for treatment of a pending application for lease renewal as a lease continued under its existing terms until entry of the final determination affecting the application for renewal; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** AS 38.35.110 is amended to read:

Sec. 38.35.110. Term of lease. Each lease of state land for pipeline right-of-way purposes must contain a provision that the lease shall run for a specified term of not greater than 30 years, and shall be renewable for additional periods of up to **30** [10] years each, so long as the lessee is in commercial operation and is in full compliance with all state law, including but not limited to state law pertaining to regulation and taxation of the pipeline facility, and is in compliance with all terms of

the lease. In making this determination, the commissioner shall take into consideration the cost of the proposed pipeline, its useful life, and the probable financing requirement for the proposed pipeline.

*** Sec. 2.** AS 38.35.110 is amended by adding a new subsection to read:

(b) If, not later than the date of expiration of the term of a lease made under (a) of this section, the lessee of a lease renewable under (a) of this section requests renewal and the lease has not been renewed, the commissioner shall continue the lease subject to the terms and conditions that were applicable to the lease in effect at the time of expiration of the lease's term. The commissioner shall continue the lease until the commissioner determines the duration of the renewed lease and renews the lease for that duration with any additional terms and conditions of the lease under renewal, or until the commissioner denies renewal if the commissioner determines that the lessee is not in commercial operation or that the lessee is not in full compliance with state law, and the denial has been adjudicated to a final decision not subject to further appeal.

*** Sec. 3.** The uncodified law of the State of Alaska is amended by adding a new section to read:

COMMISSIONER OF NATURAL RESOURCES TO AMEND CERTAIN EXISTING LEASES UNDER ALASKA RIGHT-OF-WAY LEASING ACT TO INCORPORATE PROVISION FOR RENEWAL PERIODS OF UP TO 30 YEARS. If, before expiration of the term of the original specified term of a lease first entered into under AS 38.35 that is in effect on the effective date of this Act, the lessee makes a written request, the commissioner of natural resources shall amend the lease to amend the terms under which the lease is renewable to conform to AS 38.35.110(a), amended by sec. 1 of this Act.

*** Sec. 4.** This Act takes effect immediately under AS 01.10.070(c).

22-LS0322\J

HOUSE BILL NO. 83

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SECOND LEGISLATURE - FIRST SESSION

BY THE HOUSE SPECIAL COMMITTEE ON OIL AND GAS

Introduced: 1/19/01
Referred: House Special Committee on Oil and Gas, Resources

A BILL

FOR AN ACT ENTITLED

"An Act relating to natural gas pipelines, providing a statutory definition for the portion of the constitutional statement of policy on resource development as applicable to the development and transportation of the state's natural gas reserves, amending Acts relating to construction of natural gas pipelines to require conformance to the requirements of the statutory definition, and amending the standards applicable to determining whether a proposed new investment constitutes a qualified project for purposes of the Alaska Stranded Gas Development Act; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** AS 38.05.910 is amended by adding a new subsection to read:

(b) Consistent with the statements of general state policy guiding resource development set out in art. VIII, sec. 1, Constitution of the State of Alaska, that the

resources of the state be developed "by making them available for maximum use consistent with the public interest" that appears in (a) of this section, and set out in art. VIII, sec. 2, Constitution of the State of Alaska, directing that provision shall be made by the legislature for "the utilization, development, and conservation of all natural resources belonging to the State . . . for the maximum benefit of its people," it is the policy of this state that the overall strategy for development, use, and control of a project or projects to develop and transport the state's substantial natural gas resources be directed

(1) to enhance the standard of living of state residents by

(A) ensuring that, in conjunction with out-of-state market-driven commercial demand for the natural gas, state residents and businesses will have access, direct or indirect, to that portion of the gas that will meet the reasonably foreseeable in-state demands for it, including substitution of the natural gas for depleting gas reserves in order to maintain a low-cost domestic and industrial energy source, and that the pipeline or pipelines for the transportation of the natural gas will be designed and located to be responsive to these requirements;

(B) making the maximum contribution to the development of job opportunities in this state by providing direct short-term construction and long-term operation- and maintenance-related employment on the pipeline or pipelines and by providing necessary support services; and

(C) adding significant long-term property value to the tax base of the state and its local governments, thereby providing the means to support public education, public health, transportation, and other essential state and local government projects and services;

(2) to ensure that the design, location, and construction of a pipeline or pipelines of natural gas from this state to North American markets through connection to the North American natural gas pipeline network does not foreclose implementation of gas delivery using alternative technologies and the construction of other pipelines to accommodate delivery of natural gas to tidewater for delivery to foreign and domestic markets; and

(3) to ensure construction of a pipeline or pipelines consistent with careful protection of the state's natural environment, with minimum environmental degradation, to the greatest extent possible, and with protection of fish, wildlife, and biotic resources for the use of persons who depend upon them, by using available transportation infrastructure to initiate and complete project construction and maintenance and by avoiding duplication of facilities.

*** Sec. 2.** AS 38.35.100(a) is amended to read:

(a) The commissioner shall promptly determine, in a written finding, on an application filed under AS 38.35.050, whether the applicant is fit, willing, and able to perform the transportation or other acts proposed in a manner that will be required by the present or future public interest. **For a natural gas pipeline, the commissioner shall also promptly determine, in a written finding, on an application filed under AS 38.35.050, whether the applicant's proposed use of the right-of-way will comply with the overall strategy for development, use, and control of a project or projects to develop and transport the state's natural gas resources set out in AS 38.05.910(b).** In making a determination the commissioner shall consider whether or not

(1) the proposed use of the right-of-way will unreasonably conflict with existing uses of the land involving a superior public interest;

(2) the applicant has the technical and financial capability to protect state and private property interests;

(3) the applicant has the technical and financial capability to take action to the extent reasonably practical to

(A) prevent any significant adverse environmental impact, including but not limited to erosion of the surface of the land and damage to fish and wildlife and their habitat;

(B) undertake any necessary restoration or revegetation; and

(C) protect the interests of individuals living in the general area of the right-of-way who rely on fish, wildlife, and biotic resources of the area for subsistence purposes;

(4) the applicant has the financial capability to pay reasonably

foreseeable damages for which the applicant may become liable on claims arising from the construction, operation, maintenance, or termination of the pipeline;

(5) the applicant has agreed that, in the construction and operation of a pipeline within the right-of-way,

(A) the applicant will comply with, and require contractors and their subcontractors to comply with, applicable and valid laws and regulations regarding the hiring of residents of the state then in effect or that take effect subsequently, **and**

(B) for a project or projects to develop and transport the state's natural gas resources, the applicant will also use the applicant's best efforts to contract with qualified contractors and firms in this state for work to be performed, including the fabrication and installation of required facilities; in this subparagraph, a contractor or firm is considered as qualified if the contractor or firm qualifies as an Alaska bidder under AS 36.30.170(b);

(6) for a North Slope natural gas pipeline, as that term is defined in AS 42.06.630, the applicant voluntarily agrees to use the applicant's best efforts to employ residents of this state, consistent with law; for purposes of this paragraph, a person is considered a resident if the person is physically present in the state with the intent to remain in the state indefinitely and has a home in the state.

* **Sec. 3.** AS 38.35.100(b) is amended to read:

(b) If the commissioner makes the determinations under (a) of this section favorably to the applicant, then the commissioner may grant the whole or part of the application. If the commissioner makes the determinations under **(a)** [(a)(1) - (5)] of this section favorably to the applicant but determines that the applicant is not then fit, willing, and able to perform under the application, the commissioner may grant the application under a conditional lease subject to conditions established by the commissioner that will ensure that the applicant will, within a prescribed period of time not exceeding 10 years, establish that the applicant is fit, willing, and able, under (a) of this section, to perform the transportation or other acts that will be required by

the present or future public interest. An applicant is not entitled to a notice or authorization to proceed to construction, or its equivalent, under a conditional lease until the commissioner determines in writing that the applicant has satisfactorily established that the applicant is then fit, willing, and able to perform under (a) of this section. Otherwise, the commissioner shall deny the application.

*** Sec. 4.** AS 42.06.310(d) is amended to read:

(d) **To reduce the time and cost of future connections for the injection and removal of gas from the main North Slope natural gas pipeline in order to maintain and facilitate access to a portion of the gas for use in intrastate commerce to meet the reasonably foreseeable in-state demands for it, including substitution of the natural gas for depleting gas reserves in order to maintain a low-cost domestic and industrial energy source, the** [THE REQUIREMENT OF (c) OF THIS SECTION DOES NOT APPLY TO A NORTH SLOPE NATURAL GAS PIPELINE CARRIER TO THE EXTENT THAT THE CAPACITY OF THE CARRIER'S NORTH SLOPE NATURAL GAS PIPELINE DOES NOT ALLOW FOR EXPANDED CAPACITY, AND DOES NOT APPLY TO REQUIRE A NORTH SLOPE NATURAL GAS PIPELINE CARRIER TO ENLARGE OR EXTEND ITS NORTH SLOPE NATURAL GAS PIPELINE SYSTEM. HOWEVER, THE] commission

(1) shall, notwithstanding the criteria applicable under (c) of this section, [MAY] require a North Slope natural gas pipeline [CARRIER] to **be designed and constructed in size and operating capability beyond the capacity, as measured by the average daily volume throughput, sufficient to provide gas in interstate commerce, and shall enter other appropriate orders under AS 42.06.340(b); and**

(2) may otherwise require a North Slope natural gas pipeline carrier to expand, enlarge, or extend its North Slope natural gas pipeline system if, after notice and opportunity for hearing, the commission determines that

(A) [(1)] a person making a request for expanded, enlarged, or extended service by a North Slope natural gas pipeline carrier has made a firm contractual commitment to the North Slope natural gas pipeline carrier to

transport North Slope natural gas; and

(B) [(2)] the expansion, enlargement, or extension will not result in

(i) [(A)] substantial injury, including economic injury, to the North Slope natural gas pipeline facility or its customers;

(ii) [(B)] substantial detriment to the services furnished by the North Slope natural gas pipeline facility; or

(iii) [(C)] the creation of safety hazards.

*** Sec. 5.** AS 43.82.100 is amended to read:

Sec. 43.82.100. Qualified project. Based on information available to the commissioner, the commissioner may determine that a proposal for new investment is a qualified project under this chapter only if the project

(1) [IS A PROJECT FOR THE EXPORT OF LIQUEFIED NATURAL GAS;

(2)] would produce at least 500,000,000,000 cubic feet of stranded gas within 20 years from the commencement of commercial operations; and

(2) complies with the overall strategy for development, use, and control of a project or projects to develop the state's natural gas resources set out in AS 38.05.910(b) [(3) IS CAPABLE, SUBJECT TO APPLICABLE COMMERCIAL REGULATION AND TECHNICAL AND ECONOMIC CONSIDERATIONS, OF MAKING GAS AVAILABLE TO MEET THE REASONABLY FORESEEABLE DEMAND IN THIS STATE FOR GAS WITHIN THE ECONOMIC PROXIMITY OF THE PROJECT].

*** Sec. 6.** AS 42.06.240(f) is repealed.

*** Sec. 7.** This Act takes effect immediately under AS 01.10.070(c).

SENATE BILL NO. 82

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SECOND LEGISLATURE - FIRST SESSION

BY THE SENATE RULES COMMITTEE BY REQUEST OF THE LEGISLATIVE COUNCIL

Introduced: 2/9/01
Referred: State Affairs, Judiciary

A BILL

FOR AN ACT ENTITLED

"An Act making corrective amendments to the Alaska Statutes as recommended by the revisor of statutes; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** AS 06.05.005(a)(3) is amended to read:

(3) review and approve or disapprove applications for new state banks under **AS 06.05.344** [AS 06.05.345], new bank branches under AS 06.05.399, and international or interstate branch banks under AS 06.05.555;

*** Sec. 2.** AS 13.06.050(29) is amended to read:

(29) "minor" means a person who is under **18** [19] years of age;

*** Sec. 3.** AS 16.05.930(g) is amended to read:

(g) **AS 16.05.330 - 16.05.723** [AS 16.05.440 - 16.05.723] do not apply to an activity authorized by a permit issued under AS 16.40.100 or 16.40.120, or to a person or vessel employed in an activity authorized by a permit issued under AS 16.40.100 or 16.40.120.

* **Sec. 4.** AS 21.27.560(a) is amended to read:

(a) A client who appoints an insurance producer as its broker in this state or relative to a subject resident, located, or to be performed in this state shall execute a written contract that specifically sets out the duties, functions, powers, authority, and compensation of the insurance producer, if the broker is compensated by a fee paid **by** the client or by a combination of a fee paid by a client and a commission paid by an insurer with which coverage has been placed. The written contract shall be kept in the permanent records of the insurance producer and be open to inspection by the director.

* **Sec. 5.** AS 21.42.500 is amended to read:

Sec. 21.42.500. Definitions. In **AS 21.42.345 - 21.42.500** [AS 21.42.345 - 21.42.395],

(1) "copayment" means the portion of medical care expenses in excess of the deductible to be paid by a covered individual;

(2) "deductible" means the portion of medical care expenses for which a covered individual must pay before benefits become payable;

(3) "excepted benefits" has the meaning given in AS 21.54.160;

(4) "fraternal benefit society" has the meaning given in AS 21.84.900;

(5) "health care insurance plan" has the meaning given in AS 21.54.500;

(6) "health care insurer" has the meaning given in AS 21.54.500;

(7) "placed for adoption" has the meaning given in AS 21.54.500.

* **Sec. 6.** AS 21.54.160(4)(A) is amended to read:

(A) Medicare **supplemental policy** [SUPPLEMENT HEALTH INSURANCE] as defined in **42 U.S.C. 1395ss(g)(1)** [42 U.S.C. 1345ss(g)(1)] (Social Security Act);

* **Sec. 7.** AS 21.56.050(d)(3) is amended to read:

(3) subject to the approval of the director, the board shall make an adjustment to the assessment formula for reinsuring carriers that are approved health maintenance organizations that are federally qualified under **42 U.S.C. 300e** [42 U.S.C. 300], to the extent, if any, that restrictions are imposed on those organizations that are not imposed on other small employer insurers;

* **Sec. 8.** AS 23.40.215(c) is amended to read:

(c) Notwithstanding (b) of this section, the monetary terms of an agreement entered into between a school district or regional educational attendance area and its employees are not **required to be submitted to** [SUBJECT TO APPROVAL BY] the legislature.

* **Sec. 9.** AS 24.45.041(b)(7) is amended to read:

(7) the identification of a legislator, legislative employee, or public official to whom the lobbyist is married or who is the spousal equivalent of the lobbyist; in this paragraph, "spousal equivalent" has the meaning given in **AS 39.50.200(a)** [AS 39.50.030(g)].

* **Sec. 10.** AS 38.04.900(c) is amended to read:

(c) If the regulations adopted by the commissioner under (a) of this section fail to provide for a process by which decisions of the commission may be appealed, an interested person may petition for reconsideration of a decision. The petition shall contain the information required to be submitted by AS 44.62.220 and shall be acted upon by the commissioner in the manner provided in AS 44.62.230. For purposes of this **subsection** [SECTION], a municipality is an interested person with respect to its interests in land defined in (b) of this section.

* **Sec. 11.** AS 38.05.810(i) is amended to read:

(i) Subject to AS 38.05.820, the commissioner may lease undeveloped state land, including tideland, to a port authority established under AS 29.35.600 - 29.35.730, if the state land is within the physical boundaries of the authority and is needed by the authority for purposes provided in AS 29.35.600 - 29.35.730. The commissioner may lease developed state land, including tideland, to a port authority established under AS 29.35.600 - 29.35.730 only if, (1) the developed state land is within the physical boundaries of the authority; (2) the developed state land is needed by the authority for purposes provided in AS 29.35.600 - 29.35.730; and (3) the legislature approves the lease. A lease of state land under this **subsection** [SECTION] may be for less than the appraised market value.

* **Sec. 12.** AS 38.05.821(a) is amended to read:

(a) Notwithstanding any other provision of law, a home rule or general law

municipality **that** [WHICH] accepts by conveyance or other disposition from the state a public recreation area facility developed under the terms of **P.L. 84-507, 70 Stat. 130** [P.L. 507 (70 STAT. 130)], upon application, shall receive by conveyance from the director all land owned by the state seaward of the public recreation area facility **that** [WHICH] is between the mean high tide line and the mean low tide line. The director may adopt necessary regulations providing for the conveyance of land under this section.

*** Sec. 13.** AS 38.20.060(a)(10) is amended to read:

(10) Zone 10 is a Lambert conformal conic projection of the Clarke spheroid of 1866, having standard parallels at north latitude 51 degrees 50 minutes [AS] and 53 degrees 50 minutes, along which parallels the scale shall be exact. The origin of coordinates is at the intersection of the meridian 176 degrees 00 minutes west of Greenwich and the parallel 51 degrees 00 minutes north latitude. This origin is given the coordinates: x = 3,000,000 feet and y = 0 feet.

*** Sec. 14.** AS 38.20.060(b)(10) is amended to read:

(10) Zone 10 is a Lambert conformal conic projection of the World Reference Ellipsoid, having standard parallels at north latitude 51 degrees 50 minutes [AS] and 53 degrees 50 minutes, along which parallels the scale shall be exact. The origin of coordinates is at the intersection of the meridian 176 degrees 00 minutes west of Greenwich and the parallel 51 degrees 00 minutes north latitude. This origin is given the coordinates: x = 1,000,000 meters and y = 0 meters.

*** Sec. 15.** AS 38.35.120(a)(1) is amended to read:

(1) it assumes the status of and will perform all of its functions undertaken under the lease as a common carrier and will accept, convey, and transport without discrimination crude oil or natural gas, depending on the kind of pipeline involved, delivered to it for transportation from fields in the vicinity of the pipeline subject to the lease throughout its route both on state land obtained under the lease and on the other land; **it will accept, convey, and transport crude oil or natural gas without unjust or unreasonable discrimination in favor of one producer or person, including itself, as against another but will take the crude oil or natural gas, depending on the kind of pipeline involved, delivered or offered, without**

unreasonable discrimination, that the Regulatory Commission of Alaska shall, after a full hearing with due notice to the interested parties and a proper finding of facts, determine to be reasonable in the performance of its duties as a common carrier; however, a lessee that owns or operates a natural gas pipeline

(A) subject to regulation either under the Natural Gas Act (15 U.S.C. 717 et seq.) of the United States or by the state or political subdivisions with respect to rates and charges for the sale of natural gas, is, to the extent of that regulation, exempt from the common carrier requirement in this paragraph; [IT WILL ACCEPT, CONVEY, AND TRANSPORT CRUDE OIL OR NATURAL GAS WITHOUT UNJUST OR UNREASONABLE DISCRIMINATION IN FAVOR OF ONE PRODUCER OR PERSON, INCLUDING ITSELF, AS AGAINST ANOTHER BUT WILL TAKE THE CRUDE OIL OR NATURAL GAS, DEPENDING ON THE KIND OF PIPELINE INVOLVED, DELIVERED OR OFFERED, WITHOUT UNREASONABLE DISCRIMINATION, THAT THE REGULATORY COMMISSION OF ALASKA SHALL, AFTER A FULL HEARING WITH DUE NOTICE TO THE INTERESTED PARTIES AND A PROPER FINDING OF FACTS, DETERMINE TO BE REASONABLE IN THE PERFORMANCE OF ITS DUTIES AS A COMMON CARRIER;]

(B) that is a North Slope natural gas pipeline (i) is required to operate as a common carrier only with respect to the intrastate transportation of North Slope natural gas, as that term is defined in AS 42.06.630, and (ii) is not required to operate as a common carrier as to a liquefied natural gas facility or a marine terminal facility associated with the pipeline, and is not otherwise required to perform its functions under the lease as a common carrier; for purposes of this subparagraph, "North Slope natural gas pipeline" means all the facilities of a total system of pipe, whether owned or operated under a contract, agreement, or lease, used by a carrier for transportation of North Slope natural gas, as defined by AS 42.06.630, for delivery, for storage, or for further transportation, and including all pipe, pump, or compressor stations, station equipment, tanks, valves, access roads, bridges, airfields, terminals and

terminal facilities, including docks and tanker loading facilities, operations control centers for both the upstream part of the pipeline and the terminal, tanker ballast treatment facilities, fire protection system, communication system, and all other facilities used or necessary for an integral line of pipe, taken as a whole, to carry out transportation, including an extension or enlargement of the line;

*** Sec. 16.** AS 38.95 is amended by adding a new section to article 3 to read:

Sec. 38.95.085. Definitions for AS 38.95.075 - 38.95.085. In AS 38.95.075 - 38.95.085,

(1) "commissioner" means the commissioner of natural resources;

(2) "director" means the director of the division of lands.

*** Sec. 17.** AS 40.15.050 is amended to read:

Sec. 40.15.050. Plats legalized. All plats filed or recorded with the recorder before March 30, 1953, whether executed and acknowledged in accordance with this chapter or not, are validated and all streets, alleys, or public thoroughfares shown on these plats are considered to be dedicated to public use. The last plat of the area of record on March 30, 1953, is the official plat of the area as of that date, and the streets, alleys, or thoroughfares shown on it are considered to be dedicated to public use. The streets, alleys, or thoroughfares shown on an earlier plat of the same area, or any part of it, **that are** [WHICH IS] in conflict with those shown on the official plat are considered to be abandoned and vacated.

*** Sec. 18.** AS 41.10.100(b) is amended to read:

(b) The board shall also

(1) receive and review reports concerning the use of soil resources of the state;

(2) hold public hearings and meetings to determine whether land in the state is being used in a manner consistent with sound soil and water conservation practices;

(3) make recommendations for specific action necessary to provide for the effective and orderly development of agricultural, forest, and grazing land in the state;

(4) review an appeal by an applicant or lessee from a decision of the director of the division of **lands** [LAND AND WATER MANAGEMENT] concerning a sale or lease of state agricultural or grazing land and submit its recommendations to the commissioner or hearing officer;

(5) act in an advisory capacity to the soil and water conservation districts in the state;

(6) act in an advisory capacity to the commissioner and director of the division of agriculture in the review of farm conservation plans for all state agricultural land sales in the state.

*** Sec. 19.** AS 41.17.950(13) is amended to read:

(13) "riparian area" means

(A) the areas specified in AS 41.17.116(a) on private land in the coastal forest of spruce or hemlock;

(B) the areas specified in regulations adopted by the commissioner under AS 41.17.116(b) on private land outside the coastal forest of spruce or hemlock;

(C) the area 100 feet from the shore or bank **of** [OR] an anadromous or high value resident fish water body on state land managed by the department and on other public land;

*** Sec. 20.** AS 43.40.100(4) is amended to read:

(4) "user" means a person consuming or using motor fuel, who [EITHER]

(A) purchases the fuel out of the state and ships it into the state for personal use in the state;

(B) manufactures the fuel in the state; or

(C) purchases or receives fuel in the state that is not taxed at the time of purchase or receipt or is taxed at a rate that is less than the rate prescribed by AS 43.40.010.

*** Sec. 21.** AS 44.85.320(a) is amended to read:

(a) A trustee appointed under **AS 44.85.310** [THIS SECTION] may, and shall in the trustee's name, upon written request of the holders of 25 **percent** [PER CENT]

in principal amount of the outstanding notes or bonds,

(1) by civil action enforce all rights of the noteholders or bondholders, including the right to require the bond bank authority to collect rates, charges, and other fees and to collect interest and amortization payments on municipal bonds and notes held by it adequate to carry out an agreement as to, or pledge of, the rates, charges, and other fees and of the interest and amortization payments, and to require the bond bank authority to carry out any other agreements with the holders of the notes or bonds and to perform its duties under this chapter;

(2) bring a civil action upon the notes or bonds;

(3) by civil action require the bond bank authority to account as if it were the trustee of an express trust for the holders of the notes or bonds;

(4) by civil action enjoin anything that may be unlawful or in violation of the rights of the holders of the notes or bonds;

(5) declare all the notes or bonds due and payable, and if all defaults are made good, then with the consent of the holders of 25 **percent** [PER CENT] of the principal amount of the outstanding notes or bonds, annul the declaration and its consequences;

(6) [THE TRUSTEE,] in addition to the foregoing, **excercise** [HAS] all the powers necessary for the exercise of functions specifically set out or incident to the general representation of bondholders or noteholders in the enforcement and protection of their rights.

*** Sec. 22.** AS 08.20.180(b); AS 14.43.310(b)(2); AS 18.65.250; AS 39.50.200(b)(17); AS 44.19.110, 44.19.112, 44.19.114, 44.19.116, 44.19.118, 44.19.120, and 44.19.122 are repealed.

*** Sec. 23.** This Act takes effect immediately under AS 01.10.070(c).

SENATE BILL NO. 121

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SECOND LEGISLATURE - FIRST SESSION

BY SENATOR LEMAN

Introduced: 2/27/01
Referred: Resources, Finance

A BILL

FOR AN ACT ENTITLED

"An Act adding, for purposes of the Alaska Right-of-Way Leasing Act, a definition of 'substantial change' as applied to an amended right-of-way lease application; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** AS 38.35.050(c) is amended to read:

(c) Any amendment to an application filed under this section **that** [WHICH] constitutes a substantial change in the application is subject to all provisions of this chapter applying to an original application. **For purposes of this subsection,**

(1) an amendment constitutes a substantial change in the application only if the amendment proposes

(A) a net increase in the amount of state acreage to be leased for the right-of-way that exceeds by at least 10 percent the amount of the acreage in the applicant's original application; or

(B) a change in the design of the pipeline that would use less

effective environmental or safety mitigation measures or less advanced technology than proposed in the original application;

(2) in calculating the percentage increase in acreage under (1)(A) of this subsection, each of the following must be excluded:

(A) the acreage attributable to an amendment to a right-of-way grant across federal land originally issued by the federal government, whether administered by the state or the federal government; and

(B) land subject to an existing federal right-of-way grant held by the applicant that is transferred to the state for its administration.

*** Sec. 2.** AS 38.35.080(b) is amended to read:

(b) Upon completion of the analysis but not less than 30 days before the date set for hearing an application or **an amendment to an application that, under AS 38.35.050(c), constitutes** a substantial **change in the** [AMENDMENT TO AN] application, the commissioner shall publish notice, and make copies available as provided in AS 38.35.070.

*** Sec. 3.** This Act takes effect immediately under AS 01.10.070(c).

KNOWLES ADMINISTRATION GAS PIPELINE PROJECT

MISSION STATEMENT

The Knowles-Ulmer administration is working aggressively to develop Alaska's enormous North Slope natural gas resources by advancing construction of an Alaska Highway natural gas pipeline. This pipeline project is designed to achieve the three principles most Alaskans agree on when it comes to commercializing Alaska's gas:

- Alaska hire, use of Alaska businesses and development of new gas-related industries,
- Access to natural gas for Alaskan communities, including use of gas for future projects such as liquid natural gas exports or gas-to-liquids facilities, and
- A fair share of revenues for Alaskans.

Planning Assumptions for FY 2002 Gas Pipeline Capital Budget

Timeline: July 2001 – June 2002
Project Status: Pre- and post-application
Funding Source: July to December 2001 – general fund
January to June 2002 – reimburseable under AS 38.35.140(b)

1. The FY 2001 Supplemental gas pipeline project budget is passed by the Legislature including funding for records review and work planning essential to summer 2001 field work.

2. A gas pipeline right-of-way application will be received on or about December 1, 2001 for the Alaska Highway route.

3. Construction activities will not occur during FY 2002.

4. All agencies will have a liaison and technical staff available to accomplish the FY 2002 gas pipeline activities once a capital appropriation is received.

5. Major state agency activities during this period will include:
    1. field work to identify specific route and facility siting exclusions and /or special considerations i.e., to address access, land ownership, streams, material sites, camps, compressors, solid waste facilities etc.
    2. data gathering for permit requirements (air, water, fish etc.) to help establish design requirements for the pipeline based on environmental considerations, fill information gaps, etc.
    3. participation in the Alaska Coastal Management Program process
    4. pre-application consultations with producers
    5. execution of memoranda of understanding with federal and Canadian agencies
    6. preparation for 2002 field season and development of FY 2003 work plan
    7. application and technical plan review starting in December 2001

6. A consolidated, multi-agency Gas Pipeline Office (GPO) will physically be in place beginning in July 2001.

7. As provided in Administrative Order 187, agency liaisons shall be available to manage and perform work necessary to process agency permits and authorizations, assist as necessary with other agency permits and authorizations, and provide other assistance to the State Pipeline Coordinator in their areas of expertise. Agency liaisons are responsible for supervision of staff hired to work at the GPO. Staff providing support from a regional or central office on short-term work assignments will continue to work for their supervisor.

8. SPCO will budget for and provide all work space, computers, equipment, supplies and administrative services for agency liaisons and staff assigned to the GPO unless expressly agreed otherwise.

9. Some costs incurred during the pre-application period from July – December could be reimburseable under AS 38.35.140(b) if the application is for the Alaska Highway

route. However, the working assumption is that expenditures during this period will not be reimburseable.

Description of Services in the Governor's FY 2002 Capital Gas Pipeline Budget Request

(Financial Summary Attached)

DEPARTMENT OF ENVIRONMENTAL CONSERVATION

Summary **$1,204.5**

The Department of Environmental Conservation (DEC) traditionally plays an important role in projects such as the proposed gas pipeline. The department is responsible for ensuring that impacts to the environment and human health are minimized. The project will require numerous DEC permits, plan approvals, state certifications of federal permits or approvals to operate under established general permits or DEC regulations.

During FY 2001 and FY 2002, the department will participate in updating the environmental impact studies, reviewing the State right-of-way application, and reviewing the overall project design for compliance with DEC statutes and regulations. DEC will provide pre-application assistance and permitting for major air pollution sources, such as compressor stations, and perform site-specific reviews for camp and other discharges, which take into account specific discharge and receiving water characteristics.

DEC believes that the proposed scope of work for FY 2001 and FY 2002 is the minimum level of effort necessary to provide the site-specific information needed for the planning process. By initiating the program immediately, DEC will capture the current (2001) summer field season. This proactive approach to integration of environmental protection and human health concerns into the planning process will minimize costly delays to the gas pipeline project.

Assumptions

In addition to the general planning assumptions used by all agencies, DEC has made the following assumption:

- Pre-application work with the project sponsor to update and perfect DEC permit applications[1] and supporting environmental documentation will reduce future delays in a[illegible]oving DEC permit applications. A proactive approach to permitting issues before the appli[illegible]ons are filed will eliminate the need for time-consuming and costly modifications down t[illegible]oad, ensuring that

[1] DEC approvals: The project will require numerous DEC permits, plan approva[illegible] state certifications of federal permits or approvals to operate under established general permits or DEC regulations.

- Compressor stations - construction and operation air permits, approval of stormwater pollution control plans, fuel storage spill prevention and response contingency plan approval.
- Construction Camps - water quality certification of fill permits, fuel storage spill prevention and response contingency plan approvals, solid waste disposal permits, domestic wastewater plans and permits, non domestic wastewater permits, contaminated site assessments and cleanups, food service permits, drinking water plan approval, pesticide permits.
- Pipeline excavation or VSMs - non-domestic wastewater permits, contaminated site assessments and cleanups.
- Construction material sites – non-domestic wastewater permits, contaminated site assessments and cleanups.

environmental protection is "built-in" to the project applications that are published for public review.

- DEC will be able to determine by December 2001 whether any ROW work will be done during summer 2002 that will require a permit for herbicide/pesticide use.
- DEC will receive permit applications in December 2001 that have been perfected to minimize need for additional information.

FY 2001 Immediate Pre-Application Work Tasks (April - June 2001)

- Hire Department of Environmental Conservation liaison to work with the State Pipeline Coordinator and other state agencies to establish an operating gas pipeline office.
- Hire four environmental program specialists (air, water, spill prevention & response, environmental health) to work with the project sponsor, and other state and federal agencies on issues within their program jurisdiction and expertise.
- Hire an air quality chemist to work with the project sponsor on summer air quality monitoring objectives.
- Complete a preliminary analysis of existing environmental information (ANGST EIS, federal and state lease documents, environmental plans etc.) and identify data gaps and additional information needs.
- Identify pollution prevention or control issues of concern including air, liquid and solid waste reduction, recycling and reuse plans, waste collection, treatment and disposal systems, fuel storage and handling systems, drinking water source protection, collection and treatment systems, food safety practices and pesticide or herbicide use requirements.
- Meet with the project sponsor to outline the scope of the project design, DEC authorities and approval requirements, potential issues and DEC/sponsor work contacts to work specific issues.
- Develop FY 2002 permit review staff work plans and begin recruitment to hire in July.

FY 2002 Short Term Pre-Application Work Tasks (July – December 2001)

- Hire eight plan approval and permit specialists (domestic and non-domestic wastewater, solid waste, air quality, spill prevention and response, contaminated sites) to work with project sponsor on pre-application issues and begin public notice of applications received in December.
- Provide technical field work assistance to collect ambient pre-construction air and water quality data, environmental sensitivity mapping, contaminated site identification and assessments, solid waste disposal site assessments, drinking water source assessments, and sewage disposal site assessments.
- Develop State right-of-way pollution prevention and control lease stipulations consistent with the department's authority under AS 46.03.024.
- Draft provisions in MOUs with appropriate federal and Canadian agencies on a coordinated gas pipeline approval process that serves DEC's authorities and interests.
- Conduct pre-application meetings with the project sponsor to discuss department requirements for the planning and design of fuel storage and handing facilities, drinking water, wastewater, solid waste, and food preparation facilities, stormwater and other non-domestic wastewater collection, treatment and disposal systems, air emission control systems, and review potential pesticide use.
- Review drafts of the project sponsors environmental plans as sections become available.
- Review field operations planned for summer 2002 and meet with the applicant to determine if a pesticide permit will be needed at that time.

FY 2002 Long Term Post-Application Work Tasks (December 2001- July 2002)

- If pesticides will be applied during summer 2002, hire permitting staff.
- Complete site-specific reviews for camp and other construction related discharges, which take into account specific discharge and receiving environment quality.
- Develop construction monitoring requirements and construction camp mobilization field work plans.
- Coordinate contaminated sites and assessment/cleanup schedules to compliment pipeline construction schedules.

- Participate in the development and review of the federal environmental impact statement.
- Review and approve facility plans and/or permits for camp drinking water, domestic wastewater, solid waste, and sanitation systems.
- Review and approve non-domestic wastewaster engineering plans and permits for all stream crossings, fills in wetlands, stormwater, excavation dewatering for gravel extraction and construction, discharge of hydrotest wastewaters for pipelines and storage tanks, and other environmental systems.
- Assess whether new air emissions will cause or contribute to a violation of an ambient air quality standards or air quality increment standards. Determine if the project is using the best available control technology for each applicable emission source and regulated pollutant.

DEPARTMENT OF FISH AND GAME

Summary **$636.7**

The Alaska Department of Fish and Game (ADF&G) traditionally plays an important role in projects such as the proposed gas pipeline. The department is responsible for ensuring that impacts to fish, wildlife and their habitats are minimized. For planning and oversight purposes, the gas pipeline project can be broken into three distinct phases, pre-construction, construction and post-construction. Past experience has shown the most cost-effective approach to addressing potential impacts to fish and wildlife resources is through proactive participation in the planning process (design stage for engineering efforts). Early identification of issues provides both land management planners and design engineers the time and information needed to mitigate impacts.

ADF&G believes that the proposed scope of work for FY 2001 and FY 2002 is the minimum level of effort necessary to provide the site-specific information needed for the planning process. By initiating the program immediately, ADF&G will capture the current (2001) summer field season. This proactive approach to integration of fish and wildlife concerns into the planning process will minimize costly delays to the gas pipeline project.

Assumptions

In addition to the general planning and budgeting assumptions used by all agencies, ADF&G made the following additional assumption for FY 2001 budgeting:

- A compressed timetable for gas pipeline construction requires expedited action to fulfill ADF&G work activities. Since DNR has no timetable beyond FY02, ADF&G assumed the need to be prepared for some level of construction activity in FY03.
- The applicant is Foothills and not one of or a group of oil and gas companies. This is significant because Foothills holds a federal grant of right of way and the existing EIS may only require updating. A new applicant for the Alaska Highway route may be required to initiate a new EIS process, possibly without benefit of existing proprietary information.

FY 2001 Work Activities

- Fill two positions, the Pipeline Liaison/Surveillance Supervisor and the Design/Permitting Coordinator. Emphasis will be preparation for summer 2001 field activities through records review and analysis. Additional work activities include coordination with divisional representatives to identify potential data gaps, selection and hiring of staff joining the program in FY 2002 and, working with the SPC and other agency Liaisons to create the gas pipeline office. ADF&G would like to use the existing JPO facilities to house staff, however, if office space is not available, temporary space may be available in the ADF&G, Region II facility.
- The longer it takes for ADF&G to receive funding with which to hire two lead JPO staff in FY 2001, the greater the chance that the department will lose the first of three critical field seasons (Summer '01,

Winter '01-02, and Summer '02). We believe we need to have our Pipeline Liaison/Surveillance Supervisor (R22) and Gas Pipeline Design/Permitting Coordinator (R20) *in place by April 1st* in order to ensure that ADF&G will be able to evaluate enough of the existing archival information to be able to set up and conduct an effective summer field season. The amount of lead time ADF&G needs to make these hires by April 1st depends on whether we can find qualified applicants in-state, and whether these applicants can indeed be hired (given current restrictions on hiring retirees, including under the RIP program).

FY 2002 Work Activities

Based on the above assumptions, FY 2002 work activities will be critical in formation of recommendations to: prevent any significant adverse environmental impact, including but not limited to erosion of the surface of the land and fish and wildlife and their habitat; create guidelines for revegetation and restoration activities and; protect the interests of individuals living in the general vicinity of the right-of-way who rely on fish, wildlife, and biotic resources for subsistence purposes.

ADF&G feels that protection of environmental resources is best accomplished through early identification of concerns which allows engineers an opportunity to incorporate these concerns into the design process. Many of these concerns can be identified from past experiences associated with construction of TAPS, however, a chilled gas pipeline project of this magnitude comes with many unknowns.

The work activities proposed for FY 02 represent a measured approach to addressing environmental concerns associated with the proposed gas pipeline. A strong field component is necessary because of the compressed time table and the need to have site specific information for the planning process. It is important to note that while work will begin on the tasks listed below, completion may not be realized until the state right-of-way lease is finalized.

- Coordinate with other participating agencies to develop a wetland evaluation program (planning and field). Generally, participating environmental agencies form a work group to delineate wetlands along the proposed route through a modeling effort. Field assessment of the model's accuracy is a major component of the effort.
- Develop criteria to facilitate material site selection and mining, including rehabilitation (primarily a planning task with limited field support). Alyeska Pipeline Service Company plans an aggressive workpad maintenance program in anticipation of their lease renewal efforts. Up to 1,000,000 cubic yards of material may be needed for the program. In addition, DOT regularly uses material along the entire TAPS route for new construction and maintenance. The gas pipeline will need large quantities of material to bed the pipe, build a workpad, and build access roads. ADF&G provides technical expertise on the siting of material sites (upland, floodplain, etc.) and rehabilitation of the site (erosion control, use of the overburden and other factors that enhance fish or wildlife habitat).
- Develop a fish stream list for the gas pipeline, access roads, material sites, etc (field). The fish stream list developed for TAPS has proved to be an important document for both TAPS and agency staff. The document includes information on species present and sensitive life phases used by all staff to plan instream projects and to develop criteria to protect fish resources present.
- Provide engineers with fish passage design criteria and specifications (planning). Vehicle access for the construction and operation of a gas pipeline requires crossing fish streams. Criteria for bridge placement, culvert installation and low water crossing construction is important to protect fish passage.
- Analysis of environmental impacts associated with above versus below ground pipe (substantial differences in potential impacts, waste disposal, gravel requirements, long-term rehabilitation, etc.) (planning).
- Evaluate location and siting of construction camp sites (planning and field). Proposed construction camp sites need to be evaluated for proximity to fish streams or important wildlife habitat. In addition to primary impacts, possible secondary impacts associated with increased vehicle traffic and human use of the area need to be assessed.

- Develop a surveillance and monitoring agreement with the federal government (planning and field). State and federal agencies with similar surveillance and monitoring needs share resources to accomplish common goals.
- Provide fish stream crossing specifications for a chilled gas line (planning and field). ADF&G is concerned that a chilled gas line beneath a stream may create a freeze bulb with possible impacts to fish passage.
- Recommend fish streams to be crossed using directional drilling (planning and field).
- Develop trenching guidelines for crossing fish streams (planning and field).
- Update draft state lease stipulation 1.6.1 - Plans (human/bear interactions, revegetation/restoration, material sites, disposal sites, etc.), the intent of these plans was to include adequate design criteria and specifications which would allow development of the mile by mile design using site-specific data – this was one of the lessons learned from TAPS (planning).
- Develop construction guidelines for quality control/quality assurance monitoring (planning). Generally, companies are required to have a quality control/assurance program in place prior to beginning work. ADF&G would like these programs to include a section on environmental protection and will provide input for program development.
- Evaluate any design or route changes (planning and field). The current route and design is about 20 years old. Any proposed changes to either the route or design will require further assessment.
- Develop a conceptual plan to address wildlife mitigation (planning). ADF&G will identify sensitive wildlife habitats and propose timing or activity restrictions to protect these areas.
- Provide comments on the updated EIS (planning).
- Compile existing information on subsistence uses in communities along the proposed pipeline corridor, including areas used, seasonality of harvest activities, and harvest levels.
- Assess the adequacy of existing subsistence use information for application to pipeline planning, and develop mechanisms to fill data gaps and update information as needed.
- In consultation with corridor area communities and regional organizations;
  (1) develop and prioritize a list of subsistence-related issues for consideration in formulating mitigation measures; and
  (2) outline a proposed subsistence monitoring plan for implementation upon initiation of pipeline construction activities.

OFFICE OF THE GOVERNOR
DIVISION OF GOVERNMENTAL COORDINATION

Summary **$74.4**

The Division of Governmental Coordination (DGC), in the Office of the Governor, is the lead agency for the Alaska Coastal Management Program (ACMP). Projects located in Alaska's coastal zone are reviewed by DGC for consistency with the ACMP. The portion of the gas pipeline projects that falls within Alaska's coastal zone is subject to consistency review by DGC per 6 AAC 50.

Assumptions

In addition to the general planning assumptions used by all agencies, DGC has made the following assumptions:

- DGC Project Analyst hired on May 1, 2001.
- The new DGC hire will locate either in the GPO, if it is open for business with available office space and computer equipment, or temporarily at the SPCO until the GPO office is opened.
- When available and collectable, all DGC Project Analyst costs will be fully reimbursable.

A DGC Project Analyst position will be dedicated to the start up of the GPO and coordination of pre-application assistance, the coordination of the State's review of proposals for consistency with the Alaska Coastal Management Program (ACMP) and other GPO related activities.

FY 2001 Work Activities

The ACMP involves decision making from the local government, state agencies, and federal agencies. The earlier these players get together to discuss the issues presented by the proposed project, the easier it is to avoid costly and time-consuming conflicts during the project review process. Specifically the pre-application process is a forum to:

1) Identify necessary permits;
2) Identify agency and district concerns early enough to affect design without costly added re-design;
3) Get coordinators, permitters, local government and applicants on the same page and fosters productive dialogue;
4) Avoid duplication of efforts as everyone is aware of who is responsible for what;
5) Identify potentially conflicting agency and local government requirements at the outset so that they may be resolved; and
6) Give applicants a reasonable and predictable timeline rather than starting a review that is incomplete or exceeds agency capacity.

During FY 2001, DGC will fill the Project Analyst position. The new hire will be trained on the purpose and procedures of the ACMP and agency procedures including how to coordinate consistency reviews and facilitate interagency interactions. The new position will begin to assume the primary and technical liaison role between the ACMP and other participating agencies involved in setting up the GPO pipeline office. A work plan will be developed for the DGC Project Analyst in coordination with GPO management. The DGC Project Analyst will develop briefing papers for the director on issues related to the gas pipeline.

FY 2002 Work Activities

- Coordinate among SPCO agencies during the final stages of the start up of the SPCO office.
- Provide pre-application and pre-review assistance to applicants. Work with applicants, State and federal agencies to ensure review packets and permit applications are complete.
- Assess whether it will be necessary to phase the consistency review of the project or whether all of the activities can be reviewed at one time.
- Coordinate the State's reviews of gas pipeline project applications for consistency with the ACMP.
- Work with the applicants, local and State resource agencies, and any affected coastal districts and the public to identify information requirements, potential impacts to the coastal zone, and applicable standards and regulations.
- Provide ACMP procedural information to applicants and other review participants
- Review State agency and coastal district comments to ensure that they are within the legal boundaries of the ACMP.
- Develop proposed and final consistency determinations based on comments and recommendations.
- Develop an analysis of how the project is consistent with the ACMP
- Resolve/mediate disagreements about project impacts, necessity for stipulations and interpretation of State and district policies.

DEPARTMENT OF LABOR & WORKFORCE DEVELOPMENT

Summary **$152.3**

The Department of Labor (DOL) will assess the demand for labor resulting from both the construction and operation of the gas pipeline. In an effort to ensure that a qualified workforce exists at the time of gas

pipeline construction, DOL will conduct occupational supply and demand analysis to identify potential workforce gaps. In addition, DOL will coordinate efforts to maximize the employment of Alaska residents and to ensure worker safety.

DOL will begin this work in FY 2001 by reviewing existing occupational information and identify data gaps. The information researched will include, though not be limited to, gas pipeline staffing patterns and indicators of occupational supply. Working with process industry experts, DOL will also review the existing occupational taxonomy (based on federal Standard Occupational Classifications) for adequacy. If additional occupational detail is needed to accurately analyze gas pipeline activity, more detailed occupational categories will be developed and data collection methods investigated.

FY 2002 Work Activities

Research and Analysis

- Construct Gas Pipeline Staffing Patterns: Based on the FY2001 research, DOL will construct a matrix of gas pipeline-related occupational needs by industry.
- Expand Occupational Data Collection: If needed, DOL's data collection programs will be expanded to include the collection of additional occupational information.
- Forecast Future Industry Employment: DOL will develop two industry employment forecasts, for the 2000 – 2005 and 2000 – 2010 time periods, reflecting the labor needs of the construction and maintenance of the gas pipeline. This analysis will include assessing the indirect effects of the gas pipeline project on Alaska's labor market.
- Forecast Future Occupational Employment: DOL will estimate future occupational demand resulting from the gas pipeline project.
- Identify Potential Skills Gaps: DOL will analyze occupational demand and supply data to identify potential workplace skills gaps.
- Minimize the Potential Skills Gaps: DOL will assist with the development of strategies to close the projected skills gap. Strategies may include the identification of "training gaps" and the development of career information products that encourage Alaskans, of all ages, to consider potential shortage occupations with planning their careers.

Commissioner's Offic

The DOL will hire a CPO Liaison to represent the department in all inter and intra agency deliberations; provide liaison and outreach to external stakeholders with regard to employment and training of Alaskan workers and socio-economic impacts in general; and provide for appropriate review of mechanical, electrical and health and safety issues attendant to the application process. Stakeholders include contractors, communities, labor organizations, Alaska Native organizations, and others.

DEPARTMENT OF PUBLIC SAFETY
DIVISION OF FIRE PREVENTION

Summary **$188.9**

The Department of Public Safety, Division of Fire Prevention is tasked by AS 18.70 to review all new, remodel, addition and relocated construction for fire and life safety, fire alarm and fire suppression criteria. The fire and life safety review pertains to commercial, industrial, business, institutional and residential use containing four or more dwelling units as outlined in the state adopted building, fire and mechanical codes.

Additionally, the Division of Fire Prevention monitors system operation, testing and maintenance of all fire alarm and suppression systems and conducts fire prevention inspections and enforcement actions to insure identified hazards are corrected in a timely manner. It is assumed that we will be heavily involved in helping to develop workable, reliable, flexible and reasonable fire response plans for both permanent and temporary facility uses.

- In anticipation of the application for a natural gas pipeline and the creation of one stop shopping for the application process, centered at the Joint Pipeline Office, it is important to jump-start our participation. This is so training, research, documentation requirements and pre-engineering of technical obstacles can be speedily assessed and processes are put into place.
- The result of these actions will ensure a quick and professional response to technical engineering issues, plan review of gas line facilities, support camps, and fire alarm and suppression system building permit approvals.
- We will eliminate unnecessary lag time between project submittals and project approvals, allowing us to hit the ground running once there is an applicant.
- There will already be a system in place to serve the applicant and the learning curve for the technical issues and process documentation will have already been achieved.
- It is anticipated that parts of the project will be accomplished through the design/build process. This will allow concurrent design, review and phased construction of individual and group projects at the same time and as in any major new endeavor the newest technologies will be used to increase the efficient operation of the gas line. It is important that we be aware and educated on new technologies to support these concepts as they relate to natural gas production, distribution, compression and refrigeration.
- Early on we will be able to establish working relationships with partner agencies and applicant engineers to form a basis of understanding to the intent of building, mechanical and fire codes in support of their projects.

Required training for 2 new positions (including travel) in the engineering of natural gas distribution, compression, and refrigeration of pipelines and their associated facilities will be funded through the FY 2001 supplemental budget.

FY 2002 Work Activities

- State Fire Marshal (5% of time, salary and benefits) to act on behalf of the Commissioner of Public Safety as it pertains to the Gas Pipeline Cabinet and provide fire and life safety consultant services to the acting liaison.
- Assistant State Fire Marshal (20% of time, salary and benefits) to work with the new liaison and plan reviewer to learn state and JPO operating, documentation requirements, assist in the development of FY 2003 budget and work plan and provide fire and life safety consultation services as requested in support of the gas pipeline.
- Liaison (100% of time, salary and benefits) to manage and perform work necessary to process department permits, authorizations and inspections, consult and coordinate with the SPC, develop work plans, manage department administrative functions, and supervise staff assigned to the GPO.
- Administrative Manager (5% of time, salary and benefits) to provide accountability, RSA development and processing of billings.
- Plan Reviewer (100% of time, salary, and benefits) to process all requests for plan review; consult on fire detection and suppression; pre- and post-engineering support of the gas pipeline and related facilities as it relates to state adopted building, fire and mechanical codes.

DEPARTMENT OF TRANSPORTATION & PUBLIC FACILITIES

Summary **$308.5**

Funds are needed for a liaison position for overall coordination of pipeline activities within the department and liaison to the SPCO. Technical staff is also needed to assist in highway right-of-way (ROW) permitting issues. Department of Transportation and Public Facilities (DOT&PF) is owner of the highway ROW and thus must participate in any permitting activities that take place on or across it.

Assumptions

In addition to the general planning and budgeting assumptions used by all agencies, DOT&PF made the following additional assumption for FY 2001 budgeting:

- The pipeline office will need copies of the full set of highway ROW files along the corridor as well as a full set of geotechnical reports.

Tasks and Resources

An SPCO Liaison/Engineer III will be hired May 1, 2001 and located in the Anchorage Pipeline Office This position will act as gas pipeline coordinator for the department and as liaison to the SPCO. This position will be familiar with the processes related to ROW permits for encroachments, utilities, construction, driveways, lane closures, etc. This position must be able to deal with issues as they arise concerning bridge integrity and impacts of overweight and oversized loads on the state's road system.

A Right-of-Way Agent IV position will be hired in FY 2002 to coordinate the ROW issues related to DOT&PF. Each crossing of the highway will require a full survey of the ROW at that location, research of land ownership and coordination with the underlying fee owner. If the underlying fee owner is a federal agency, then 23 CFR requires that the federal agency also approve the permit. Surveys performed by the Sate would be accomplished under consultant contracts administered by this position. The position would oversee land ownership research conducted by the Dept. of Law or by contract. The position would also develop the permit terms necessary to protect the interests of the traveling public at each location.

A Right-of-Way Agent IV position will be hired in FY 2002 to coordinate activities between the Northern Region and the Pipeline Office. Since the proposed route is entirely within the Northern Region boundaries, most planning, design, construction, maintenance and operations of the highway system along the corridor will be impacted. Records research and issue resolution will be the primary duties of this position.

An Engineer I position will be hired in FY 2002 to provide technical engineering support for the DOT&PF permitting activities. The position will evaluate highway design and operation issues such as sight distance, highway geometrics, traffic analysis, structures, and maintenance impacts related to each permit. This position will coordinate the DOT&PF response to any proposed use of the State's bridges and potential changes to the hydraulic condition at bridge piers and abutments due to the addition of other structures. This position will also provide Department coordination of requests for overload permits on the State's highways and bridges during construction.

The FY 2002 also includes contractual funds to respond to requests from potential applicants for land ownership and other ROW files inventory and copying.

DEPARTMENT OF NATURAL RESOURCES
STATE PIPELINE COORDINATOR'S OFFICE

Summary **$4,965.9**

During FY 2001 and FY 2002, the State Pipeline Coordinator's Office (SPCO) will implement Administrative Order 187. The major task associated with AO 187 implementation is the creation of a functional Gas Pipeline Office (GPO). This task will be started in FY 2001 and completed in FY 2002.

The GPO will be an operating unit of the SPCO. The Federal-State Joint Pipeline Office is the other operating unit of the SPCO.

Gas Pipeline Office

The GPO will provide multi-agency one-stop permitting, authorization, and oversight, comparable to that provided to the Trans Alaska Pipeline and common carrier pipelines on the North Slope by the Joint Pipeline Office. The main tasks associated with creation of the GPO are finding and moving to new offices; staffing the office; and creating the internal policies and procedures that will allow the participating agencies to work effectively together. These tasks will be initiated in FY 2001 and completed in FY 2002, culminating in the opening of the new GPO in July 2002. Hiring of many technical staff will be delayed until an application is received to reduce expenses.

Before receipt of an application, the agencies involved in the GPO will:

- Inventory existing information on the Alaska Natural Gas Transportation System (highway) route. Determine which of the information may be proprietary.
- Create a comprehensive list of required permits and authorizations and information and actions needed to process those permits and approvals for a highway application. Identify impediments to issuance of permits and authorizations.
- Develop and implement an aggressive plan for filling information gaps. Implementing the plan will provide a technical jump-start to permit and authorization processing.
- Develop aggressive plans to quickly and efficiently overcome identified impediments and process authorizations and permits. Creation of the plans will provide a procedural jump-start to permit and authorization processing. Creating the plans within the GPO will allow coordination between the tasks and resources of individual agencies, reducing duplication and redundancy, and producing better products faster and cheaper.
- Work with federal and Canadian agencies to agree upon application requirements and quick, efficient. coordinated review and approval processes. The goals of the effort are Memoranda of Understanding between the parties and participation of those entities in the Gas Pipeline Office.
- Work with project proponents to assure that statutory and regulatory requirements are understood and that the applications that are submitted to agencies within the GPO are as complete and responsive to those requirements as possible. Minimizing post-application information requests may be the single most effective means of speeding application processing.
- Begin engaging and informing the public of permitting and authorization efforts. More public participation efforts at the beginning will streamline statutorily required efforts later.

Many of these tasks will be initiated in FY 2001, once a supplemental appropriation is received, and completed in FY 2002.

After receipt of permit applications during FY 2002, GPO staff will be processing those applications.

The SPCO will provide the management and administration of the GPO. SPCO technical staff within the GPO will perform lands and engineering work to process a gas pipeline right-of-way application, and will manage work by other state agencies and consultants in support of ROW application processing.

In addition to the general assumptions applicable to all gas pipeline budget requests, the SPCO budget request for GPO work is based on the following assumption:

- Hiring of SPCO and other GPO staff will be in the amounts and according to the timing indicated in the budget supporting documents.

Gas Pipeline Office Management

During FY2001, the State Pipeline Coordinator will delegate to his deputy all pipeline authorization and oversight responsibilities that do not relate to a gas pipeline. By May 2001, the SPC will be focused exclusively on the gas pipeline project. In FY2001 and FY 2002, he will focus on managing the Gas

Pipeline Office startup and other tasks identified above. The Deputy SPC will assist the SPC with gas pipeline work until those delegations are completed.

Two deputy SPCs for the Gas Pipeline Office will be hired, the first in May 2001 and the second at the beginning of FY2002. One will assume responsibility for office and project management, including: work plan review, approval, and consolidation; budget review, approval, and consolidation; permit and authorization requirement and progress tracking; and field season planning and implementation. The second deputy SPC will manage relations among the many interested and involved parties to the state gas pipeline process, including involved state commissions, committees, and agencies, the federal and Canadian governments, and other pipeline route landowners. The second deputy will also manage media relations and public outreach.

A Special Assistant will be hired at the beginning of FY 2002 to communicate and coordinate with the DNR Commissioner's Office, the Gas Pipeline Cabinet, and the Natural Gas Policy Council. The Special Assistant will provide staff support to the Commissioner and Gas Cabinet as requested by the DNR Commissioner.

The Public Information Officer hired at the beginning of FY 2002 will be responsible for responses to public and media inquiries, and for the Gas Pipeline Office public outreach program. The latter duty is now envisioned to include a quarterly newsletter, a web site, and bi-monthly public meetings, in addition to the notices, meetings, and hearing that will be statutorily required. The existing JPO PIO will provide support to SPCO gas pipeline efforts until the position is filled.

The Executive Secretary hired at the beginning of FY 2002 will provide support to the SPC and deputies. Existing staff will provide that support until the position is filled.

The Engineering, Right-of-Way, and Administration sections are discussed below.

Gas Pipeline Office Right-of-Way Section

During FY 2001, the ROW Section of the GPO will initiate the following work prior to receipt of an application:

- Review previously submitted materials for relevancy to statutory requirements and likely proposals.
- Begin to develop checklists of requirements for authorizations, lists of impediments to authorizations, and a workplan to address both.
- Assist in the establishment and maintenance of the administrative record.
- Begin coordination with other landowners and land managers.

The ROW Section will continue the tasks above in FY 2002, and assist in the preparation and review of work scopes and budgets for outside expertise (generally from other state agencies) to support the workplan.

During FY 2002, the ROW Section will receive the application, process the application fee, provide public notice of the application, and receive and respond to comments on the application. They will then:

- Review submitted materials.
- Begin the ACMP review.
- Begin acreage accounting.
- Begin preparation of the contract for the lease of the land, including development of special terms and conditions.
- Begin coordination with any NEPA process.
- Begin processing other required permits and authorizations, including those necessary for material sales, access roads, disposal sites, construction camps, communication sites, and water withdrawals.

During FY 2002, the ROW Section will provide quasi-legal assistance to the Commissioner and State Pipeline Coordinator.

Gas Pipeline Office Engineering Section

The Engineering Section will evaluate the adequacy of pipeline system engineering across state-owned land. The work will ensure that sound engineering practices have been followed and that, where assumptions or judgments have been made, they are reasonable and justified. The evaluation is likely to involve engineering expertise from SPCO staff, ADOT staff (through RSAs), and outside consultants.

The engineering staff will perform the following work during FY 2001(assuming the supplemental appropriation is received):

- Review previously submitted materials for relevancy to requirements and likely proposals.
- Begin to develop checklists of engineering requirements for authorizations, lists of engineering challenges, questions, and impediments, and a responsive work plan.
- Assist project proponents in planning their engineering work, to assure that the work is performed in a manner that allows efficient review by GPO staff.
- Establish and maintain the engineering files and records.

During FY 2002, the engineering staff will continue the tasks above, and will:

- Coordinate with jurisdictional agencies to identify environmental, safety, and other requirements that must be addressed in the project design basis before detailed engineering is undertaken.
- Manage engineering consultants supporting the engineering work plan by developing scopes of work, budgets, and schedules, reviewing progress against work orders, and approving work products.
- Coordinate engineering reviews with other landowners and managers, and appropriate jurisdictional agencies.
- Approve design basis submittals.

Consulting engineers will provide specific discipline reviews of design basis documents and support data submitted by the applicant. Engineering disciplines that may be involved in the FY 2002 reviews include geotechnical, geophysical, hydrological, civil, electrical, mechanical, corrosion, and welding. In addition, reviews by chemists and physicists may be warranted.

Gas Pipeline Office Administration Section

An Administration Manager will be hired in May 2001 to oversee all administrative aspects of the startup and the functioning GPO. The manager will supervise the administrative staff that perform or support hiring, space procurement, supply and equipment procurement, space allocation, personnel management, computer system administration, document production, records management, budgeting, accounts payable and receivable, billing, reception, and other administrative tasks.

A System Administrator will be hired in May 2001 to set up and maintain a local area network for the new facility. He will purchase, set up, and configure computers. An Assistant System Administrator will be added to the GPO staff at the beginning of FY02.

A Records Manager will be hired in May 2001 to establish and maintain physical and electronic filing systems for agencies and functions with the GPO, and ensure compliance with applicable State and Federal retention schedules and regulations. The Records Manager will supervise the filing clerks; one clerk will be hired at the beginning of FY 2002, and two will be added after receipt of an application.

A temporary Procurement Specialist will be a hired at the beginning of FY 2002 for a period of less than a year to establish new accounts with local vendors, and purchase equipment and supplies for the new office.

An Administrative Assistant will be hired at the beginning of FY 2002 to handle personnel actions, timesheets, billings, RSAs, accounts receivable and payable, training, assist the Procurement Specialist with purchasing, and supervise the Administrative Clerks. The clerks will handle word processing, filing, mail handling, travel coordination and reception. At the beginning of FY 2002, three clerks will be hired to provide support to designated agency staff within the GPO, and two clerks will be hired to handle GPO

travel and mail. A receptionist will be hired at the beginning of FY02 to greet visitors, keep track of staff, receive and distribute incoming faxes, and otherwise assist the administrative staff.

Gas Pipeline Office Procurement

Assumptions leading to contractual budget requests are provided in the support documents. Additional comments on specific items follow:

- We intend to "fast track" the file inventory contract, since much of the early GPO work will be based on the results of that effort. File inventory work will occur in FY 2001.
- The GPO will establish a shared records management system with the Joint Pipeline Office in FY 2002 that will require rental of an appropriate storage location and the purchase of basic files equipment.
- Engineering assistance was described above, and will occur in FY 2002.
- We expect staff recruitment to be difficult, and have included recruitment assistance in our request. Most of the costs are in FY 2001, with some continuing into FY 2002
- The requested archeological, sociological, economic, and appraisal assistance will be used for processing the right-of-way and other permit applications and for state interaction with federal processes such as NEPA. These are data that can be developed early, and that are normally developed by the state and not requested from the applicant. All work will occur in FY 2002.
- The public outreach items are based on an expectation that the GPO will begin a continuous outreach program in FY 2002 that will continue through permitting and construction.
- The Public Notice line item is for all Public Notices by all GPO agencies during FY 2002.
- The DNR Support Service Division will provide administrative support for the GPO in FY 2001 and FY 2002.
- Assumptions for rent, travel, equipment are provided.

DEPARTMENT OF NATURAL RESOURCES

Division of Mining, Land, and Water, Realty Services
Land Records Information Section
Division of Geological and Geophysical Survey
Division of Mining, Land, and Water, Water Section
Division of Parks and Outdoor Recreation, Office of History and Archaeology

Summary **$810.4**

During Fiscal Year 2001, the Department of Natural Resources (DNR) will work with the State Pipeline Coordinator's Office (SPCO) and others to implement Administrative Order 187. The major DNR tasks associated with AO 187 implementation include land title work, mapping, geologic data assessment, hydrologic assessment, and archeological assessment. Each of these tasks will be completed in FY 2002.

Assumptions

- An early jump on land status and right-of-way issues will offer valuable input on routing alternatives and address permitting issues.
- The present demand for maps will continue and requests for increased detail will be made.
- Geologic hazard mitigation requires a state perspective that is broader than the narrow right-of-way focus of an applicant. The broader view can affect selection of routing alternatives.
- Preliminary knowledge of construction materials is needed to assist cost projections, site planning, and route adjustments.
- Initiating hydrographic review of existing literature and water data will save time, especially in the federal environmental review defined by the National Environmental Protection Act (NEPA).

- Initiating hydrologic review and compilation of existing literature and water data will save time, especially in the federal environmental review defined by the National Environmental Protection Act (NEPA).
- Compiling existing literature on archeological resources and preparing for site specific field work for summer 2001 will save time with the clearances required for permitting.

Deliverables

1. Title Report and Title System
   This task includes the development of a title report for lands along the pipeline route that will define and ownership and use rights. Land title documents, maps, and text will be organized into a web-based storage and retrieval system accessible by all parties. This approach is much more efficient, cost effective, and user-friendly than a paper-based system.

2. Gas Pipeline Maps
   Maps provide graphical information on routes, ownership, and landform. Initially supports needs of policy makers for preliminary information on routing and constraints. This effort will support agencies needs to view detailed information related to respective permitting duties.

3. Geologic Assessment
   This task determines current level of knowledge about geologic hazards and construction materials that could affect future gas pipeline design, route adjustments, construction, and safety.

4. Hydrologic Assessment
   This assessment of hydrologic data identifies and compiles current knowledge on surface and ground water quantity, quality, and timing. These data are needed for final pipeline routing and design. Protection of fisheries habitats and wetlands are dependent upon knowledge of water. Water data is critical to environmental analysis required under NEPA.

5. Archeological Assessment
   This task assesses the current level of knowledge on archaeological sites listed on the Alaska Heritage Resources Site inventory, identifies information gaps, and assesses survey and evaluation needs.

Justification

Task 1: Title Report and System
- An overland route will traverse complex federal, state, and private land holdings. Knowledge of detailed land ownership, right-of-ways, and land use constraints are essential to routing and permitting decisions.
- Once issued, the title report can be easily updated electronically to include changes in conveyance.
- Sharing title reports knowledge via electronic / Internet networks will be much more efficient than the present paper-based solution. This project builds a web-based land title reporting system. Cost is minimized by simply extending existing system capability.
- The current system is not workable for customers. A single title report for one route could easily create a pile of paper over three feet thick - just for one copy. Customers include SPCO, Department of Law, federal solicitor's offices, public interest groups, and applicants.
- The means to associate related federal land records with state records is best accomplished with an electronic storage and retrieval system. This approach leverages federal investments in records automation.
- The interface will permit easy search of the records by location (e.g. meridian, township and range, or route milepost), geographic name, case file, etc.

Task 2: Gas Pipeline Maps
- New maps will be needed to help management make informed land and resource decisions related to the gas pipeline route. State mapping work will be coordinated across agencies.

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- Customers: Maps will be requested and used by the Gas Pipeline Cabinet, SPCO, other DNR managers and staff, ADFG, ADEC, DOTPF, legislators, federal agencies, potential applicants, and others.
- Mapping needs range from general overviews to detailed route and land ownership information.

Task 3: Report on Status of Geologic Hazards and Materials

- This report will utilize existing data to identify potential geologic hazards and their probable extent. Identification of hazards is the first step in geologic hazard mitigation.
- Knowledge of prior geological work will help eliminate redundancy, saving time and money by avoiding duplicate studies.
- Contractors and engineers must know about geologic materials they will encounter on site, and the availability of construction materials (appropriate rock, sand, gravel). This report will provide a basis for personnel and equipment cost estimatesby the applicant.
- Detailed, accurate, and current geologic data is the foundation of engineering geology and geologic hazard identification. Presently DNR does not know the state of the geologic information base for the proposed gas pipeline corridor nor for the geologic hazards that may exist within it.
- The most effective and economic construction and route adjustment alternatives can be outlined and compared without impeding progress during actual construction. For example, DOT has experienced significant cost overruns on some projects due to encountering more resistant bedrock than anticipated or from inadequate supplies of gravel accessible to contractors. Similar situations could arise during construction of the proposed gas pipeline if the state does not have adequate geologic information.

Task 4: Hydrologic Assessment

- This task will speed the application process and any required state decision process or federal NEPA update through the compilation of hydrologic data, and rapid access to all pertinent data needed for decisions on routing, design, and construction.
- Identification and compilation of applicable hydrologic data will eliminate repetition of previous work, and pin point where additional site specific data are needed. This efficiency will save time and reduce cost.
- Areas where conflicts between water quality/quantity issues and fisheries habitats, wetland habitats, or users of water can be identified early in the route assessment and design process. Substantial savings and speed of design and construction can be realized if routing and design are done to minimize mitigation efforts.
- Sizing of all stream and river crossings are dependent upon design for maximum expected discharge. Design engineers must know maximum expected flows for all effected waterways to protect the pipeline itself, the affected physical and biologic environment, and the safety of people.

Task 5: Archaeological Assessment

- Identification of known archaeological sites and unsurveyed areas of high potential for sites is essential information for policy makers.
- Knowledge of prior archaeological work will avoid duplication of field inventory and site evaluation studies, thereby saving time and money.
- The most effective route alternatives and adjustments can be outlined and compared, if adequate understanding of the archaeological sites within the corridor is available beforehand.
- Mitigation measures that protect archaeological sites can be formulated prior to construction to avoid cost overruns and delays during construction.

Immediate Pre-Application Work Tasks (April - July 2001)

- Build a working system for title reports; integrate with existing DNR land records.
- Hire Natural Resource Officer to begin title research.
- Hire GIS Specialist / Analyst Programmer III to support title work and mapping demands.
- Begin work on title reports; look for overlap between TAPS renewal and the gas line.
- Generate preliminary maps and routing graphics to support multiple user needs.

- Hire non-perm geologists for compiling existing data on geologic hazards and construction materials, complete about 25% of this task.
- Map detailed route location showing proposed ANGTS pipeline route. Verify resolutions on information on alternate routes; initiate mapping database for the project.
- Hire non-perm archaeologists to compile known archaeological site location data and identify areas of insufficient data that require survey and evaluation.

Short Term Pre-Application Work Tasks (July 2001 – June 2002)

Title Report/System and Mapping

- Realty Services Section will complete title work associated with the gas pipeline route on a township-by-township basis. Realty Services provides the updated title report prior to the final approval process. Township reports become available through the web based system as each one is competed.
- Land title and legal support documents will be scanned to augment the title reports. These documents include any actions affecting the State of Alaska title to lands along the proposed route. The scanned images will be used in a low-cost web retrieval system.
- Status Graphics Unit will automate the remaining mylar-based townships that lie within the corridor. All townships will be combined into a parcel level database on state ownership and land status. These data will be used in title reports and detailed mapping. Pending actions that affect title will be updated on a priority basis.
- Build a geographic information system (GIS) that supports multi-agency mapping and spatial data demands as expressed primarily through the State Pipeline Coordinator's Office. Contain cost by adding incremental capacity to DNR GIS operation. Incorporate essential federal digital land records.

Geologic Hazards and Materials Assessment

- Locate and assemble all available and pertinent geologic data on the trans-Alaska pipeline corridor from Prudhoe Bay to Delta Junction, Alaska.
- Create a computer accessible geo-referenced database of all geologic maps and reports for the area within the corridor.
- Create a digital geologic map-file archive for the corridor and a digital document-file archive.
- Quantify geologic and geologic hazard data coverage within the corridor and display the ranking in map format (this is not a geologic hazards assessment).
- Compile an office-based reconnaissance of construction materials resources in the vicinity of the proposed gas pipeline route from Prudhoe Bay to the Yukon border.
- Create a GIS application that will allow a broad spectrum of users to easily access and display the currently available data.

Hydrologic Assessment

- Identify and compile all pertinent hydrologic data for the proposed pipeline corridor.
- Assemble a computer accessible GIS database of hydrologic data for the pipeline corridor route.
- Identify areas of conflict between users, e.g. areas of high value for fisheries or wetlands habitats with the design needs of the pipeline and/or other users of the water.
- Identify specific sites within the pipeline corridor where insufficient data exist to adequately address routing and design needs.
- Use a geographic information system (GIS) to display and share the results – i.e. use a computer system, not a paper system, to facilitate and encourage easy retrieval and use of needed hydrologic information.

Archeological Review

- Locate and assemble all available and pertinent archaeological data within the corridor.
- Create a digital archaeological map atlas of known archaeological site locations for the corridor in GIS compatible format with level of evaluation and status, i.e., tested, excavated, or determined eligible for the National Register.

- Verify locations and determine size of important archaeological sites in crucial areas of the corridor.
- Conduct field reconnaissance in specific, unsurveyed areas of high archaeological site potential within the corridor.

DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS

Summary **$226.7**

Each of the following gas pipeline-related studies will be initiated in FY 2001 and completed in FY 2002.

ANS Gas Pipeline Studies (Royalty Modification)
In addition to the risks associated with the enormous cost of an ANS gas development project and the uncertain future of potential gas markets, successful completion of the project could depend on the economic impact of the State's fiscal regime. Of particular concern is how and when the State earns revenue for its royalty share of the resource. Alaska's royalty regime is regressive and insensitive to a project's profitability. The royalty regime also is insensitive to the risks assumed by the project developer. Although the State's tax policy vis-à-vis the gas pipeline have been examined, the effect of the State's royalty ownership of the gas resource has not been studied.

This study will examine how the royalty "take" of the State affects the ANS gas project and identify alternative royalty mechanisms. The alternatives will be designed to afford the greatest positive contribution to the success of the project at the least cost to the State's royalty revenue. Issues such as what is appropriate revenue share that the State should receive for its royalty ownership, the timing of royalty revenues, and how the royalty share should be valued will be studied. The study will be designed to precede a more detailed evaluation of ANS gas pipeline economics that would be needed if an AS 38.05.180(j)-type royalty modification is required.

Modification of the State's royalty on the gas that will supply the ANS Gasline project may remove an impediment to the project's successful completion. If this is the case, the State will need to understand what changes to the royalty regime will produce the best results.

ANS Gas Pipeline Study (Royalty-In-Kind ANS Gas Marketing Strategy and In-state Natural Gas Demand)

It is timely to fund this project as the ANS natural gas pipeline route location and out-of-state markets are being finally determined. Natural gas from Cook Inlet has provided Southcentral Alaskans with a low cost and clean burning fuel for over thirty years. The proximity of natural gas has given a location advantage for industry, and lower heating and electric bills for local businesses and residences. Other communities in Alaska could enjoy these same benefits if their requirements are identified and a portion of the large gas reserves on the Slope are directed to meet their needs.

In addition, the large, mature, Cook Inlet gas fields are nearing their end-of-life production discoveries of similar size in this well-known basin are uncertain, but unlikely. Any future loss of natural gas to Southcentral will cause unemployment and high investment cost to households forced to convert from their existing gas-fired furnaces and hot water heaters to alternative fuel sources.

The citizens of the state may benefit if royalty gas is sold in-state to guarantee a supply to local users and perhaps earn higher revenues. However, royalty gas sold in-state may crowd out small ANS gas producers from a ready market and produce a disincentive to new and smaller entrants on the North Slope who may bring competition to lease sales and energy to exploration ideas.

This research project will reconcile these conflicting forces and provide a structure for decision-making for royalty-in-kind policy and that produces the best overall, long-term, policy for the supply of ANS gas to Alaska residents.

Gas Pipeline Supply Side Study

For FY 2001, the Division of Oil and Gas will begin a study to quantify the additional gas resources that might be available for development from sources along and near possible natural gas pipeline routes across the state. Additional natural gas resources might be available from the eastern Beaufort Sea, the ANWR coastal plain, and the Brooks Range areas. Natural gas resources might also be found in the Yukon-Kandik, Tanana, Minchumina-Holitna, Susitna, Copper River and Cook Inlet Basins of central and south-central Alaska. Estimates of the volume of these potential gas resources and possible reserves, the types of gas present and their locations, a discussion of developmental issues and the timing with which such potential resources might be brought on-line to supply additional product to an Alaska gas pipeline (and possibly community trunk-lines) will contribute significantly to any gas-line feasibility study and to out-year planning as the project proceeds. This project will require FY 2002 capital budget funding for completion.

Approval of the supplemental will allow the division to initiate project planning and make early commitments for geological studies to be conducted during summer 2001. Failure to accomplish field work in 2001 will likely force the division's field studies to continue into summer 2002. Authorization of this supplemental will allow division staff to begin compilation and analyses of existing literature and geological data (maps, field samples, sample analyses, geophysical data) necessary for design of the summer's field programs.

ANS Gas Sales (Reservoir Studies)

Major gas sales from the Prudhoe Bay reservoir will likely result in lower annual reservoir pressures compared to the no-gas-sales case. Little reliable and detailed information exists in the public domain concerning the effect of major gas sales on oil production rates and ultimate recovery of oil from Prudhoe Bay. Some oil production could be deferred while some may also be lost forever depending on the timing of gas sales, the volumes involved and the mitigation measures employed to stem pressure decline. The goal of this project would be to gather information from the producers and various consultants and make the information available to interested parties. Detailed reservoir simulation models would not be built and run since the cost would be prohibitive. Information primarily would have to come from the Prudhoe Bay lessees. Without that cooperation the project would not succeed. Depletion options for the Point Thomson reservoir could, but need not, be included in this study. A consultant would be retained to review the data and results for completeness and accuracy.

The state as a North Slope gas and oil royalty owner needs to know what effect gas sales will have on future oil production (volume and timing) and how any perceived negative effects from major gas sales can be managed and mitigated. In addition to gas sales, NGLs and LPGs are available to send down the gas line along with the gas if sales of these products are justified. Sales of additional NGLs (now mixed with the oil in TAPS or sold to other north slope fields for enhanced oil recovery) and sales of LPGs (the same molecules now used at Prudhoe Bay for miscible injectant) can also effect future oil production both at Prudhoe Bay and across the North Slope. Understanding the effects and trade offs of the various gas sales options and analyzing the various pipeline scenarios against the effects on future oil production will reduce uncertainty around the project and help define "ramp up" strategy, use of gas from fields other than Prudhoe Bay, gas liquids options, reserves and timing trade offs and annual volumes of gas reasonably available for sale. Members of the public, the Legislature and the AOGCC will want these types of physical waste and economic waste questions analyzed and answered before the gas line project goes forward. The project sponsors will want at least implicit approval from the regulatory agencies that the project can proceed under the basic assumptions that the project sponsors put forward. Moving forward with this reservoir study now will prevent a later delay or reevaluation of the preferred alternative in the future. It will take considerable time to award a contract, establish contacts with the North S lope lessees, assemble the required data, analyze the data and then report the results. To the extent effort and work products can be shared between DNR and the AOGCC, that sharing will occur.

ALASKA OIL AND GAS CONSERVATION COMMISSION

Summary **$500.0**

The Alaska Oil and Gas Conservation Commission (AOGCC) is required to evaluate the effects of gas sales on oil recovery from the Prudhoe Oil Pool in order to carry out its statutory obligation to prohibit ph ical waste of oil and gas, and achieve maximum ultimate recovery of those resources. Specifically, the AOGCC needs to know what effect gas sales will have on oil recovery and what options are available to mitigate potential negative effects on oil production. It is critical to identify and understand issues associated with Prudhoe gas sales versus continuing gas injection for enhanced oil recovery. Currently, the AOGCC does not have monetary resources or adequate staff to conduct this study.

Gas that is proposed for sale is currently being re-injected to maintain reservoir pressure to increase oil recovery. In general, maintaining reservoir pressure increases ultimate oil recovery. In the Prudhoe Bay Field, reservoir pressure is partially maintained through a combination of gas re-injection and water injection. Reservoir pressure is gradually declining in a controlled manner to accommodate the diverse recovery mechanisms in the reservoir. In general, gas production on a large scale will cause lower reservoir pressure that, if unmitigated, may result in reduction of ultimate oil recovery. We propose a study to evaluate how to most effectively and efficiently achieve greater recovery of both oil and gas.

The AOGCC proposes a two-phase approach to the problem. The first phase is currently in progress. An independent, outside expert was hired to assist in establishing a scope of critical issues and make recommendations for subsequent evaluation of gas sales issues and course of action for the AOGCC. Phase one will be paid from existing FY01 appropriations.

Recommendations of phase one will be carried out by phase two and will result in a comprehensive technical study and report that identifies effects on oil production by the Gasline Project and what methods can be employed to mitigate negative impacts on ultimate recovery.

Based on the recommendations developed in phase one, the second phase will encompass one of the three following options:

- Independent evaluation (estimated $3,000,000)
- Audit of the owners' internal evaluation (estimated $500,000)
- Other option recommended by the Phase I consultant

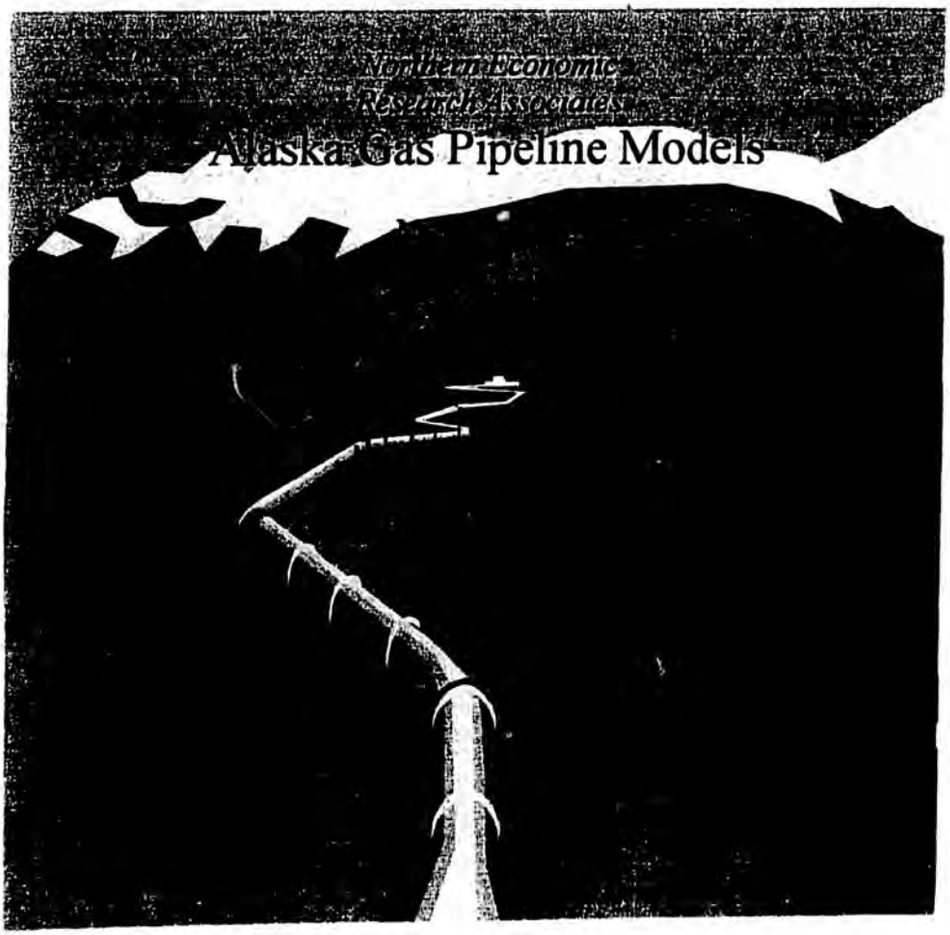
As a comparison, an AOGCC sponsored independent study of Prudhoe Bay reservoir performance and depletion plans performed in 1978 cost approximately $7,000,000.

The cost of the project is dependent on two factors:

- The consultant's recommendations made from phase one, which should be received before April 30, 2001.
- The amount of information and internal evaluations the owners willingly share versus the amount of work the AOGCC must perform independently because the owners do not supply the information. The more information that is supplied, the lower to cost of phase two will be. Conceivably, if the owners supply enough information, the project cost could be less than $500,000.

Depending on which option is executed, phase two could involve a tremendous amount of data and interpretation, resulting in significant staff-hours.

Early initiation of the study of gas recovery and its impact on fluid recovery will benefit the State of Alaska by identifying and understanding conservation issues early. The study will assure that mitigation factors



CD: ALASKA GAS PIPELINE MODELS, BY NORTHERN ECONOMIC RESEARCH ASSOCIATES, MAY 13, 2002.

(CD WAS LEFT IN THIS FILE SINCE IT'S CONTENTS ARE LARGE SPREADSHEETS WHICH ARE DIFFICULT TO COPY OR MICROFICHE. COPIES ARE AVAILABLE AT LEG. RESEARCH LIBRARY [LRAL] + STATE LIBRARY)

LAWS OF ALASKA

1973

Source	Chapter No.
FSS-FCCS HCS CSSB 3	3

AN ACT

Relating to pipelines; and providing for an effective date.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. AS 38.35.010 is amended by adding a new subsection to read:

(b) The State of Alaska reserves unto itself all rights, powers, privileges and immunities not preempted by federal interstate commerce laws and regulations in the right-of-way leasing of any state lands for pipeline construction, transmission, or operation within its boundaries.

* Sec. 2. AS 38.35.020 is amended to read:

Sec. 38.35.020. GRANT OF RIGHT-OF-WAY LEASE. (a) Rights-of-way on state land including rights-of-way over, under, along, across, or upon the right-of-way of a public road or highway or the right-of-way of a railroad or other public utility, or across, upon, over, or under a river or other body of water or land belonging to or administered by the state may be granted by noncompetitive lease by the commissioner for pipeline purposes for the transportation of oil, products or natural gas under those conditions prescribed by law or by administrative regulation. Except to the extent authorized by an oil and gas lease or unit agreement approved by the state, no person may engage in any construction or operation of any part of an oil, products, or natural gas pipeline, which in whole or in part is or is proposed to be on state land unless that person has obtained from the commissioner a right-of-way lease of the land under this chapter.

(b) The commissioner may by regulation exempt the construction or operation of field gathering lines or any

reasonable classification of them from the requirement of a right-of-way lease under this chapter.

* Sec. 3. AS 38.35.030 is amended to read:

Sec. 38.35.030. ABANDONMENT, REDUCTION OR IMPAIRMENT OF SERVICE OF PIPELINE. No lessee may abandon any portion of a pipeline that is subject to a lease granted under this chapter, or operation or transportation, service, or sale by it, or reduce or impair service, except in accordance with the terms of the lease or sec. 40 of this chapter.

* Sec. 4. AS 38.35.040 is amended to read:

Sec. 38.35.040. TEMPORARY OR EMERGENCY SERVICE OR TEMPORARY ABANDONMENT, REDUCTION OR IMPAIRMENT OF SERVICE BY LESSEE. The commissioner may, either upon a request made in the form he shall by regulation require, or upon his own motion without request, authorize or require temporary or emergency rendering of service or temporary or emergency abandonment, reduction or impairment of service by a pipeline of a lessee without compliance with secs. 50 - 100 of this chapter. Nothing in this section prevents a carrier from temporarily suspending operations in the event of an emergency which threatens public health or safety; however, notice shall be given the commissioner as soon as possible.

* Sec. 5. AS 38.35.050 is repealed and re-enacted to read:

Sec. 38.35.050. APPLICATIONS FOR RIGHT-OF-WAY LEASES. (a) A person or persons desiring to own a pipeline which is proposed to be located in whole or in part on state land, shall apply for a noncompetitive right-of-way lease of the state land.

(b) Applications under (a) of this section shall be made in a form and manner prescribed by regulation, and shall include any and all data, information, plans and exhibits which the commissioner determines are necessary to prepare the analysis required by sec. 80 of this chapter and to make a decision under sec. 100 of this chapter.

(c) Any amendment to an application filed under this section which constitutes a substantial change in the application is subject to all provisions of this chapter applying to an original application.

(d) All persons owning or planning to own an interest in a pipeline or proposed pipeline subject to a lease must join in the application under (a) of this section. Any person employed by the lessee in operating the pipeline is bound by the covenants of the lease applicable to functions within the scope of his employment as if he were an applicant under the lease and the state may enforce any breach of a covenant directly against an operator who is not in compliance with the covenant.

* Sec. 6. AS 38.35.060 is repealed.

* Sec. 7. AS 38.35.070 is amended to read:

Sec. 38.35.070. NOTICE OF APPLICATION. Upon receiving

an application under sec. 50 of this chapter, the commissioner shall

(1) cause notice of it to appear in a daily newspaper of general circulation published in the vicinity of the location of the proposed pipeline, the notice to include:

(A) a general description of the land involved;

(B) a summary of the substance of the application;

(2) file copies of the application with each coordinate agency;

(3) furnish at cost copies of a notice or application to persons requesting them; and

(4) provide other publication and notice he considers reasonable and appropriate to inform the public of the application.

* Sec. 8. AS 38.35.080 is amended to read:

Sec. 38.35.080. ANALYSIS AND PUBLIC HEARING. (a) The commissioner shall, within a reasonable time after receiving the application, prepare an analysis of the application or of the matter of which he was notified, including a proposal for action if feasible; a proposed lease and a general statement of his basis and purpose, if favorable action is proposed; or, when a proposal for action is not feasible before a hearing, a description of the subjects and issues involved.

(b) Upon completion of the analysis but not less than 30 days before the date set for hearing an application or a substantial amendment to an application, the commissioner shall publish notice, and make copies available as provided in sec. 70 of this chapter.

(c) The commissioner shall set all applications for public hearing as soon as practicable, if a public hearing on an application is requested by any person within 30 days of publication of notice under sec. 70(a) of this chapter or if the proposed action being considered involves a substantial public interest. The commissioner shall set the application for public hearing and publish notice of the time and place of the public hearing at least 30 days before the hearing.

(d) Except to the extent specified in sec. 190(b) of this chapter, the provisions of the Administrative Procedure Act (AS 44.62) do not apply to hearings held under this section.

* Sec. 9. AS 38.35.100 is repealed and re-enacted to read:

Sec. 38.35.100. DECISION ON APPLICATION. (a) The commissioner shall promptly determine, on an application filed with him under sec. 50 of this chapter, whether the

applicant is fit, willing and able to perform the transportation or other acts proposed in a manner that will be required by the present or future public interest. In making a determination the commissioner shall consider whether or not

(1) the proposed use of the right-of-way will unreasonably conflict with existing uses of the land involving a superior public interest;

(2) the applicant has the technical and financial capability to protect state and private property interests;

(3) the applicant has the technical and financial capability to take action to the extent reasonably practical to

(A) prevent any significant adverse environmental impact, including but not limited to, erosion of the surface of the land and damage to fish and wildlife and their habitat;

(B) undertake any necessary restoration or revegetation; and

(C) protect the interests of individuals living in the general area of the right-of-way who rely on fish, wildlife and biotic resources of the area for subsistence purposes;

(4) the applicant has the financial capability to pay reasonably foreseeable damages for which he may become liable on claims arising from the construction, operation, maintenance or termination of the pipeline.

(b) If the commissioner makes these determinations favorably to the applicant, then he may grant the whole or part of the application. Otherwise, he shall deny the application. In order to grant the whole or part of the application the commissioner shall offer a lease to the applicant for its acceptance through signing of the lease and agreeing to comply with its terms, conditions, and obligations. Only upon proper acceptance of offered lease by the applicant within 30 days after its having been presented is the grant of the application consummated.

* Sec. 10. AS 38.35.110 is amended to read:

Sec. 38.35.110. TERM OF LEASE. Each lease of state land for pipeline right-of-way purposes shall contain a provision that the lease shall run for a specified term of not greater than 30 years, and shall be renewable for additional periods of up to 10 years each, so long as the lessee is in commercial operation and is in full compliance with all state law, including but not limited to state law pertaining to regulation and taxation of the pipeline facility, and is in compliance with all terms of the lease. In making this determination he shall take into consideration the cost of the proposed pipeline, its useful life, and the probable financing requirement for the proposed pipeline.

* Sec. 11. AS 38.35.120 is repealed and re-enacted to read:

Sec. 38.35.120. COVENANTS REQUIRED TO BE INCLUDED IN LEASE. (a) A noncompetitive lease of state land for a right-of-way for an oil or natural gas pipeline valued at $1,000,000 or more may be granted only upon the condition that the lessee expressly covenants in the lease, in consideration of the rights acquired by it under the lease, that

(1) it assumes the status of and will perform all of its functions undertaken under the lease as a common carrier and will accept, convey, and transport without discrimination crude oil or natural gas, depending on the kind of pipeline involved, delivered to it for transportation from fields in the vicinity of the pipeline subject to the lease throughout its route both on state land obtained under the lease and on other land; however, a lessee who owns or operates a natural gas pipeline subject to regulation either (A) under the Natural Gas Act (15 U.S.C. 717 et. seq.) of the United States, or (B) by the state or political subdivisions with respect to rates and charges for the sale of natural gas, is, to the extent of that regulation, exempt from the common carrier requirement in this paragraph; it will accept, convey, and transport crude oil or natural gas without unjust or unreasonable discrimination in favor of one producer or person, including itself, as against another but will take the crude oil or natural gas, depending on the kind of pipeline involved, delivered or offered, without unreasonable discrimination, that the Alaska Pipeline Commission shall, after a full hearing with due notice to the interested parties and a proper finding of facts, determine to be reasonable in the performance of its duties as a common carrier;

(2) it will interchange crude oil or natural gas, depending on the kind of pipeline involved, with each like common carrier and provide connections and facilities for the interchange of crude oil or natural gas at every locality reached by both pipelines when the necessity exists, subject to rates and regulations made by the appropriate state or federal regulatory agency;

(3) it will maintain and preserve books, accounts and records and will make those reports that the state may prescribe by regulation or law as necessary and appropriate for purposes of administration of this chapter;

(4) it will accord at all reasonable times to the state and its authorized agents and auditors the right of access to its property and records, of inspection of its property, and of examination and copying of records;

(5) it will provide connections, as determined by the Alaska Pipeline Commission under AS 42.06.340, to facilities on the pipeline subject to the lease, both on state land and other land in the state, for the purpose of delivering crude oil or natural gas, depending on the kind of pipeline involved, to persons (including the state and its political subdivisions) contracting for the purchase at wholesale of crude oil or natural gas transported by the pipeline when required by the public interest;

(6) it shall, notwithstanding any other

provision, provide connections and interchange facilities at state expense at such places the state considers necessary if the state determines to take a portion of its royalty or taxes in oil or natural gas;

(7) it will construct and operate the pipeline in accordance with applicable state laws and lawful regulations and orders of the Alaska Pipeline Commission;

(8) it will, at its own expense, during the term of the lease

(A) maintain the leasehold and pipeline in good repair;

(B) promptly repair or remedy any damage to the leasehold;

(C) promptly compensate for any damage to or destruction of property for which the lessee is liable resulting from damage to or destruction of the leasehold or pipeline;

(9) it will not transfer, assign, or dispose of in any manner, directly or indirectly, or by transfer of control of the carrier corporation, its interest in a right-of-way lease, or any rights under the lease or any pipeline subject to the lease to any person other than another owner of the pipeline (including subsidiaries, parents and affiliates of the owners), except to the extent that the commissioner, after consideration of the protection of the public interest (including whether the proposed transferee is fit, willing and able to perform the transportation or other acts proposed in a manner that will reasonably protect the lives, property and general welfare of the people of Alaska), authorizes; the commissioner shall not unreasonably withhold his consent to the transfer, assignment or disposal;

(10) it will file with the commissioner a written appointment of a named permanent resident of the state to be its registered agent in the state and to receive service of notices, regulations, decisions and orders of the commissioner; if it fails to appoint an agent for service, service may be made by posting a copy in the office of the commissioner and filing a copy of it in the office of the lieutenant governor and by mailing a copy to the lessee's last known address;

(11) the applicable law of this state will be used in resolving questions of interpretation of the lease;

(12) the granting of the right-of-way lease is subject to the express condition that the exercise of the rights and privileges granted under the lease will not unduly interfere with the management, administration, or disposal by the state of the land affected by the lease, and that the lessee agrees and consents to the occupancy and use by the state, its grantees, permittees, or other lessees of any part of the right-of-way not actually occupied or required by the pipeline for the full and safe utilization of the pipeline, for necessary operations

incident to land management, administration, or disposal;

(13) it will be liable to the state for damages or injury incurred by the state caused by the construction, operation or maintenance of the pipeline and it will indemnify the state for the liabilities or damages;

(14) it will procure and furnish liability and property damage insurance from a company licensed to do business in the state or furnish other security or undertaking upon the terms and conditions the commissioner considers necessary if the commissioner finds that the net assets of the lessee are insufficient to protect the public from damage for which the lessee may be liable arising out of the construction or operation of the pipeline.

(b) For a right-of-way lease granted under this chapter for an oil or natural gas pipeline valued at $1,000,000 or more to be valid and of legal effect, it must contain the terms required to be inserted under the provisions of secs. 110 - 140 of this chapter. An oil or natural gas pipeline right-of-way lease granted under this chapter that does not contain the required terms is null and void and without legal effect and does not vest any interest in state land or any authority in the carrier granted the lease.

(c) The commissioner may insert in any right-of-way lease other reasonable provisions and conditions that he determines the public interest requires.

(d) The lease will also contain terms and conditions that are reasonably necessary to obligate the lessee, to the extent reasonably practicable, to

(1) prevent conflicts with other existing uses of the land involving a superior public interest;

(2) protect state and private property interests;

(3) prevent any significant adverse environmental impact, including but not limited to the erosion of the surface of the land, and damage to fish and wildlife and their habitat;

(4) restore and revegetate during the term and at termination of the lease; and

(5) protect the interests of individuals living in the general area of the right-of-way who rely on the fish, wildlife, and biotic resources of the area for subsistence purposes.

(e) In the event the commissioner proposes to offer a lease or leases to two or more lessees for the same pipeline, the commissioner may include terms in the lease or leases which establish the limit of the obligations and liabilities of each lessee arising under this chapter or under the lease or leases.

(f) The commissioner may, at his discretion, include any or all of the terms set out in this section in leases

of state land for products pipeline right-of-way purposes.

* Sec. 12. AS 38.35.130 is amended to read:

Sec. 38.35.130. RIGHT-OF-WAY EASEMENTS OR LEASES ACQUIRED FROM OTHERS. (a) The lessee may, if the commissioner delegates the function to it, condemn, by declaration of taking, under AS 09.55.420 - 09.55.450, real property and acquire leases of or easements or rights-of-way on lands in the state required for right-of-way purposes for a pipeline subject to the lease on behalf of and as agent for the state in which title to or interest in the land shall vest.

(b) The lease shall contain a covenant that the land, right-of-way, or easement acquired under this section is or will form part of the land leased to the lessee.

* Sec. 13. AS 38.35.140 is repealed and re-enacted to read:

Sec. 38.35.140. PAYMENT OF RENTAL AND COSTS. (a) The lease price for a right-of-way lease shall be the annual fair market rental of the state lands included in the right-of-way based on the appraised fair market value of the land. The lease price is payable annually in advance on or before the anniversary of the lease. The appraised fair market rental value shall be adjusted periodically under the provisions of AS 38.05.105. Rental may not be charged for any land acquired by the lessee under sec. 130(b) of this chapter and conveyed without cost to the state.

(b) The lessee shall reimburse the state for all reasonable costs incurred in monitoring the construction of the pipeline on the right-of-way.

* Sec. 14. AS 38.35.150 is repealed.

* Sec. 15. AS 38.35.160 is repealed.

* Sec. 16. AS 38.35.170 is repealed and re-enacted to read:

Sec. 38.35.170. FORFEITURE OF LEASE. Failure to begin construction of the pipeline facility within a reasonable time of the granting of a right-of-way lease under this chapter for reasons within the control of the lessee or failure of an owner of an interest in the granted right-of-way substantially to comply with the terms of the right-of-way shall be grounds for forfeiture of the right-of-way interest of the lessee or owner in an action brought by the commissioner in the superior court. Before the commencement of any action for forfeiture of an interest in a right-of-way under this section, the commissioner shall give the lessee or owner of the interest notice in writing of the alleged default and shall not commence the proceeding unless the lessee or owner of the interest has failed to initiate good faith efforts to cure the default within 60 days of the notice of the alleged default.

* Sec. 17. AS 38.35.180(c) is amended to read:

(c) Neither this section nor the state's obtaining an injunction or recovering penalties extinguishes any civil

cause of action arising out of a violation of this chapter or the provisions of a right-of-way lease.

* Sec. 18. AS 38.35.190(b), (c) and (d) are repealed.

* Sec. 19. AS 38.35.200 is repealed and re-enacted to read:

Sec. 38.35.200. JUDICIAL REVIEW OF DECISIONS OF COMMISSIONER ON APPLICATION. (a) An applicant or competing applicant or a person who has a direct financial interest affected by the lease who raises objections within 60 days of the publication of notice under sec. 70 of this chapter are the only persons with standing to seek judicial review of a decision of the commissioner under sec. 100 of this chapter.

(b) The only grounds for judicial review of a decision of the commissioner are

(1) failure to follow the procedures set out in this chapter; or

(2) abuse of discretion so capricious, arbitrary or confiscatory as to constitute a denial of due process.

* Sec. 20. AS 38.35.210 is amended to read:

Sec. 38.35.210. DELEGATION OF COMMISSIONER'S AUTHORITY. The commissioner may delegate to an employee of the Department of Natural Resources or the Department of Law the authority granted under this chapter, except for the authority to execute leases.

* Sec. 21. AS 38.35.220(d) is repealed.

* Sec. 22. AS 38.35.230 is repealed and re-enacted to read:

Sec. 38.35.230. DEFINITIONS. In this chapter

(1) "commissioner" means the commissioner of natural resources;

(2) "coordinate agencies" includes Department of Labor, Department of Highways, Department of Environmental Conservation, and the Alaska Pipeline Commission;

(3) "lease" means the instrument or extension of an instrument issued under this chapter granting a leasehold interest in state land for pipeline right-of-way purposes to a person and authorizing the construction or operation of, or transportation, service or sale by a pipeline for crude oil, natural gas, or products;

(4) "lessee" means a person or persons holding a valid lease issued by the commissioner;

(5) "natural gas" includes all hydrocarbons produced at the wellhead not defined as oil;

(6) "oil" includes crude petroleum oil and other hydrocarbons regardless of gravity which are produced at the wellhead in liquid form and the liquid hydrocarbons

known as distillate or condensate recovered or extracted from gas, other than gas produced in association with oil and commonly known as casinghead gas;

(7) "pipeline" or "pipeline facility" means all the facilities of a total system of pipe (whether owned or operated under a contract, agreement, or lease) used by a carrier for transportation of crude oil, natural gas, or products for delivery, for storage, or for further transportation, and including all pipe, pump or compressor stations, station equipment, tanks, valves, access roads, bridges, airfields, terminals and terminal facilities, including docks and tanker loading facilities, operations control center for both the upstream part of the pipeline and the terminal, tanker ballast treatment facilities, and fire protection system, communication system, and all other facilities used or necessary for an integral line of pipe, taken as a whole, to effectuate transportation, including an extension or enlargement of the line;

(8) "product" means refined crude oil, crude tops, topped crude, processed crude petroleum, residue from crude petroleum, cracking stock, uncracked fuel oil, fuel oil, treated crude oil, residuum, gas oil, casinghead gasoline, natural gas gasoline, naphtha, distillate, gasoline, kerosene, benzine, wash oil, waste oil, blended gasoline, lubricating oil, blends or mixtures of petroleum and any liquid product or by-product derived from crude petroleum oil or natural gas;

(9) "state land" means

(A) "state lands" as defined in AS 38.05.-365;

(B) public land of the United States selected by the state under sec. 6 of the Alaska Statehood Act of 1958 (PL 85-508; 72 Stat. 395), as amended, and real property of the United States transferred to the state under secs. 21, 35 and 45 of the Alaska Omnibus Act of 1959 (PL 86-70; 73 Stat. 141), as amended;

(C) any interest owned by the state in land;

(10) "transportation" means the shipment or carriage by a pipeline of crude oil, natural gas, or products from an upstream terminus in one or more fields or points of production or supply of the minerals to a downstream terminus in one or more points for delivery of the minerals to a purchaser or consignee, for storage, or for further carriage or shipment, including shipment or carriage within the state that may be classified as interstate or foreign transportation to the extent that the transportation may constitutionally be subjected to the provisions of this chapter, as well as all services necessary to effectuate shipment or carriage, including, among other things, the receipt, storage, processing, handling, transfer in transit, forwarding and delivery of the minerals.

Sec. 23. AS 38.35 is amended by adding new sections to

read:

Sec. 38.35.205. LEASE SAVINGS CLAUSE. A judicial finding that any term or condition of a right-of-way lease issued under this chapter is unlawful or invalid may not operate to invalidate the lease or any other term or condition of the lease.

Sec. 38.35.225. BINDING EFFECT OF COVENANTS. By entering into a lease under this chapter, the lessee is bound by all the covenants provided for in the lease to the full extent of the power of the state to impose those covenants under its authority as owner of the land to be leased or under its police or regulatory powers or otherwise; provided that the right of the lessee to challenge the power of the state to require such a covenant as owner of the land to be leased or under its police or regulatory powers or otherwise is preserved until such time as action to enforce the covenant is taken by the state.

* Sec. 24. AS 09.55.240(a)(12) is amended to read:

(12) for the location of pipelines for gathering, transmitting, transporting, storing, or delivering natural or artificial gas or oil or any liquid or gaseous hydrocarbons, including, but not limited to, pumping stations, terminals, storage tanks, or reservoirs, and related installations.

* Sec. 25. AS 38.05.020(c)(1) is amended to read:

(1) granting leases of state land for pipeline right-of-way purposes;

* Sec. 26. AS 38.05.020(c)(2) is amended to read:

(2) leasing, purchasing, or otherwise acquiring (including condemning by declaration of taking), easements or other interests in land in this state for the purpose of utilizing or granting leases of the land, easements or interests for pipeline right-of-way purposes;

* Sec. 27. AS 38.05.020(c)(4) is amended to read:

(4) investigating any matters concerning any lessee with a view to assuring compliance by it with its right-of-way lease, this chapter, and any other applicable state or federal law;

* Sec. 28. AS 38.05.330 is amended to read:

Sec. 38.05.330. PERMITS. The director, without the prior approval of the commissioner, may issue permits, rights-of-way or easements on state land for secondary roads, trails, ditches, field gathering lines or transmission and distribution pipelines not subject to AS 38.35, telephone and transmission lines, log storage, oil well drilling sites and production facilities for the purposes of recovering minerals from adjacent lands under valid lease, and other similar uses or improvements, or for the limited personal use of timber or materials. The commissioner, upon recommendation of the director, shall

establish a reasonable rate or fee schedule to be charged for these uses. In the granting, suspension or revocation of a permit or easement of lands, the director shall give preference to that use of the land which will be of greatest economic benefit to the state and the development of its resources. However, first preference shall be granted to the upland owner for the use of a tract of tideland, or tideland and contiguous submerged land, which is seaward of the upland property of the upland owner and which is needed by the upland owner for any of the purposes for which the use may be granted.

* Sec. 29. AS 42.06.310 is amended by adding a new subsection to read:

(c) Every common carrier shall, when ordered by the Alaska Pipeline Commission, extend or enlarge its pipeline or storage facilities provided the extension or enlargement shall be found to be reasonable and required in the public interest and that the expense involved will not impair the ability of the common carrier or public utility to perform its duty to the public.

* Sec. 30. The commissioner of natural resources shall submit to the members of the Eighth Legislature not later than September 1, 1974 a full report covering all lands conveyed under provisions of AS 38.05.063 and 38.05.076. The report shall contain a description of all parcels conveyed under the Act including acreage (to include a detailed plat of each parcel), land classification, appraised value, lease or sale value, proposed land usage, and any other information the commissioner may feel necessary to an understanding of the particular disposal.

* Sec. 31. AS 38.05.063 and 38.05.076 are repealed effective September 1, 1974.

* Sec. 32. This Act takes effect on the day after its passage and approval or on the day it becomes law without approval.

Approved by governor: November 19, 1973
Actual effective date: November 20, 1973