

SCOMM

129:1

geli

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 Committee 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 not 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!

Our Gas. Our Future



➤ 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:		Mean=2.334
	Count	%	
Strongly Favor	100	26.0%	
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:		Mean=2.766
	Count	%	
Strongly Favor	144	37.4%	
Mildly Favor	129	33.6%	
Neutral	24	6.2%	
Mildly Oppose	52	13.6%	
Strongly Oppose	35	9.1%	

Our Gas, Our Future

- 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%
Mildly Favor	64	16.6%
Neutral	31	8.2%
Mildly Oppose	102	26.6%
Strongly Oppose	179	46.4%

Mean=1.019

- 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%



Our Gas. Our Future



- 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%

Our Gas, Our Future



- 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%

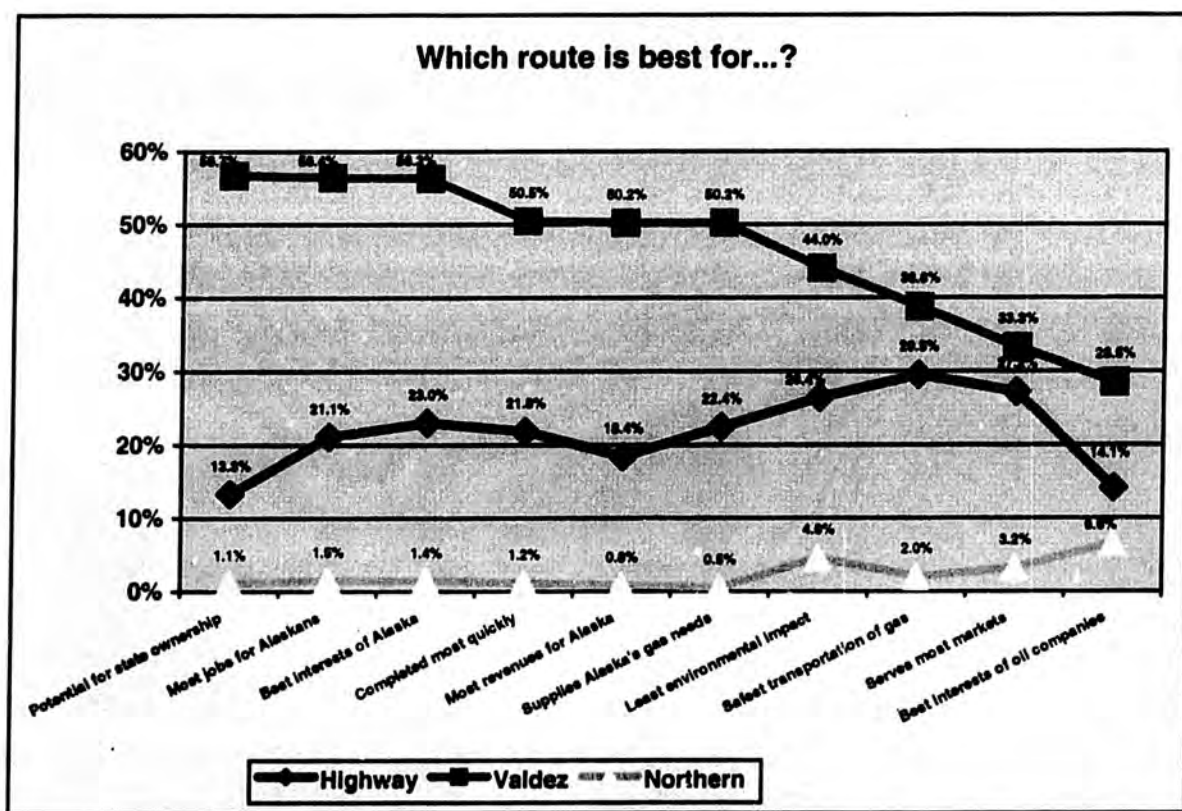
- Has the most potential for state ownership?

	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%

Our Gas, Our Future

- 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.



Official Business

ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

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)



Official Business

ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

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

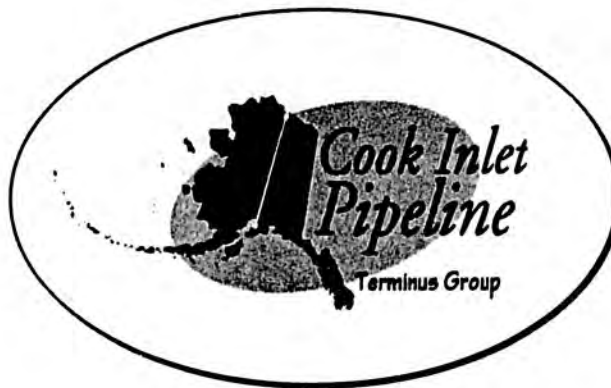
3:45 - 4:30 p.m.

- 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
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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Alaska Natural Gas Pipeline



7/13/01

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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.

North Slope Reserves Are Huge !

**35 Trillion cubic
feet of Natural Gas
has been
Discovered on the
North Slope**

7/13/01

2

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 For

- **LNG production and export**
- **Gas to Liquids(GTL) production**
- **A Midwest gas pipeline through Canada**

7/13/01

3

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.**

7/13/01

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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%)

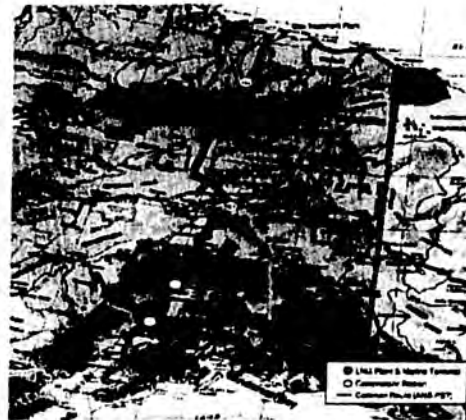
These are the right players. They have natural gas reserves, they have the expertise & experience that comes from decades of producing natural gas. They have world wide natural gas marketing experience. They have successfully permitted and built projects throughout the world.

The Sponsor Group has completed Phase I of their Feasibility Study

- Looking at a Cook Inlet terminal

Or

- Anderson Bay near Valdez



7/13/01

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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.

A Gas Pipeline Will Provide:

- **A 7 billion dollar construction project**
- **Long term industry jobs**
- **Industry support jobs**
- **Increased jobs throughout the State**

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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.

Along the Cook Inlet Route There Are:

- **CONSUMER NEEDS**
- **INDUSTRY NEEDS**
- **SPACE FOR NEW
INDUSTRY**

7/13/01

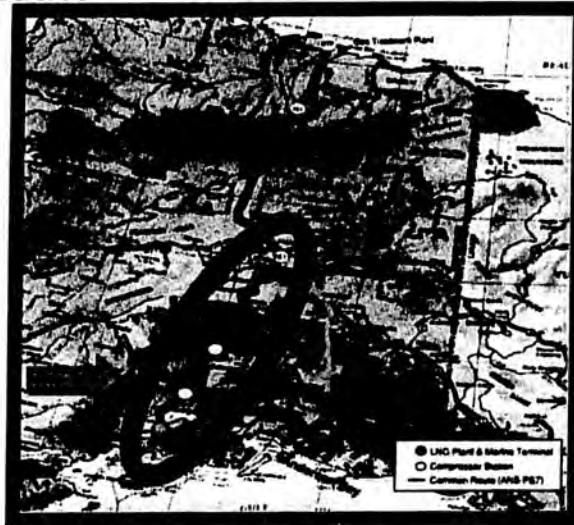
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Read

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

Consumer Needs

70% Of Alaskans Live Along the Cook Inlet Route



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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.

CONSUMER NEEDS

A Cook Inlet Route Will Provide Gas For

- **Consumers along the route**
- **Light industry along the route**
- **LNG or compressed gas to the Bush**
- **Vehicles and heavy equipment that utilize natural gas**

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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



7/13/01

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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.

INDUSTRY NEEDS

PHILLIPS LNG PLANT HAS:

- Safe Produced LNG
- On time delivery of LNG
- Successfully marketed LNG
- and
- LNG facilities across the world are patterned after the Cook Inlet LNG facility

7/13/01

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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.

INDUSTRY NEEDS

Industries that Use Natural Gas

- Agrium
- Phillips Alaska Inc.
- Tesoro
- BP's Gas To Liquid Plant
- Electrical Power Plants
- There is even a LNG facility in Mat-Su

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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.

NEW INDUSTRY

- Space in Nikiski
- Space in Mat-Su
- Space along the route

7/13/01

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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 at 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.

Here Are Some Other Important Reasons For A Cook Inlet Route

- **Cook Inlet works together**
- **Cook Inlet is wide and safe**
- **Cook Inlet has a close relationship with the oil and gas industry**

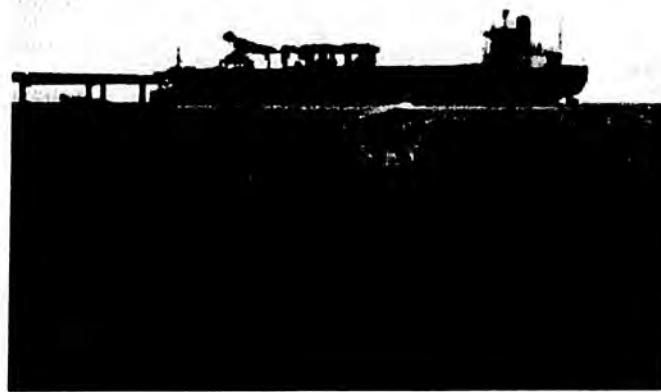
7/13/01

15

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 Works Together!



7/13/01

16

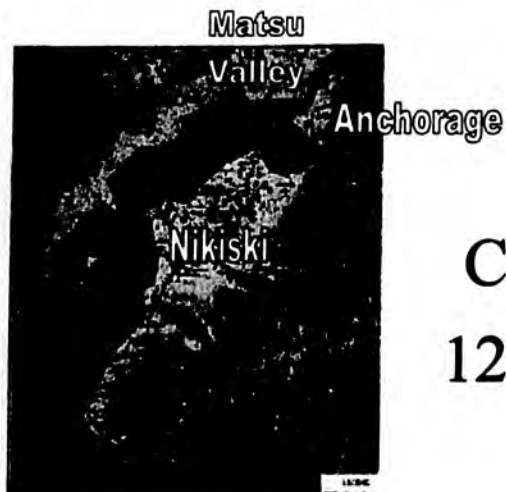
Cook Inlet's oil and gas industry has always worked together with the commercial fishing industry and tourism industries.

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

7/13/01

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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



7/13/01

18

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.

A Cook Inlet Route

- **Will serve Alaskan consumers**
- **Will protect existing industries and jobs**
- **Has the space for new industry**

7/13/01

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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.

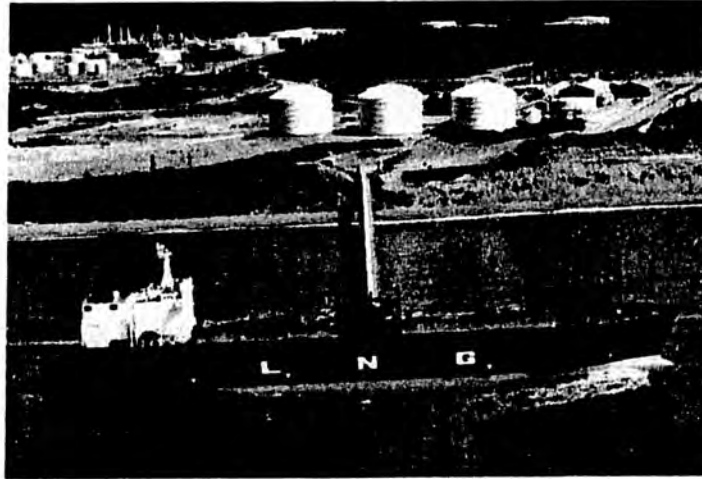
A Cook Inlet route will protect existing industries, and

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!



7/13/01

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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

Example
Less Favorable Scenario

"bare bones" - barely economic

5

ALCAN route to Alberta

\$3 gas price in Chicago

\$1.00 ~~cost~~ 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

7

Page 1

*Assumes no price effect,
Keep everything constant*

Volume sensitivity

(9)

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:

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

*costs go
up when
you
change
values*

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

BASE

11

STATE REVENUE - MORE FAVORABLE SCENARIO							
					State	Addit	
					Corp Inc	Sev Tax	
					Tax	from	
	Property		Severance	Corp Inc	from pipeline	ELF	
	Tax	Royalties	Tax	Tax	tariffs (see)	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	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 Discussions 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:

<u>Period (In Years)</u>	<u>10 % Discount Factor¹</u>	<u>Present Value</u>
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



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 transportation 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

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 -- 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



2

1

Gulf of Mexico Annual Gas Production Projections

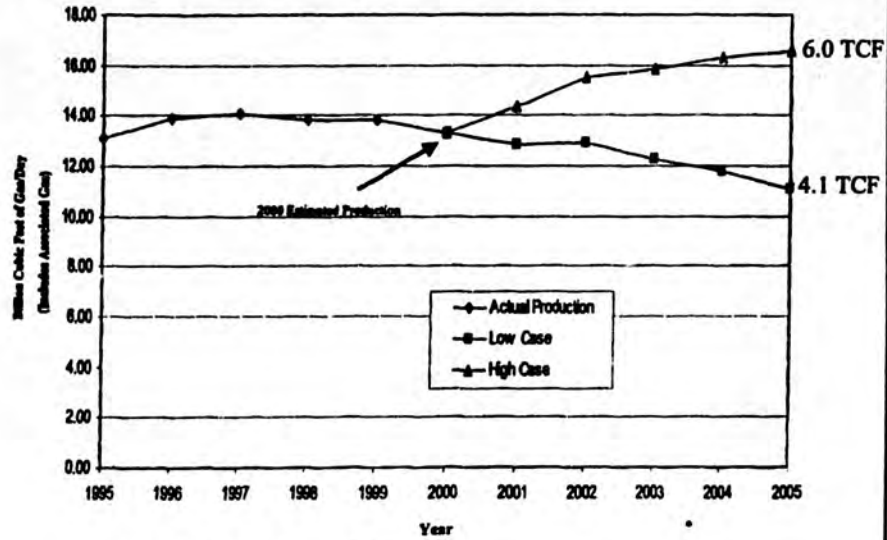
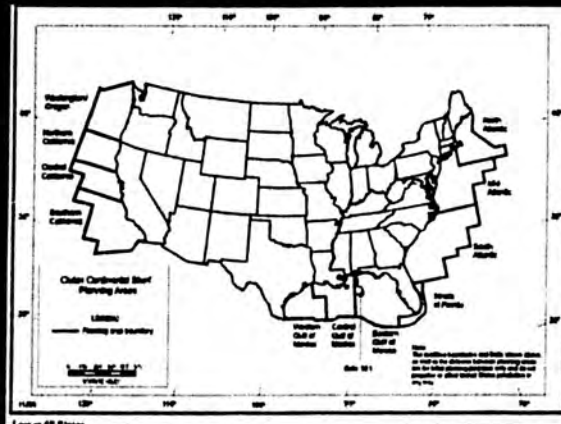


Figure 2. - Gas Production Rate Projections, Gulf of Mexico Region

3

Limitations in the Lower 48



Areas Off Limits

Atlantic	14.5% of total
GOM	12.5% of total
West Coast	15.5% of total
Rockies	1.5% of total

4

Alaska OCS Potential

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

	Oil billions barrels	Gas TCF
• <u>Alaska OCS Total</u>	<u>17 - 35</u>	<u>55 - 227</u>
• 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



8

Coastal
management
program

Special Considerations

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



9

during
break up -
waters 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



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



11

For more information

The screenshot displays the MMS (Minerals Management Service) website. The main header reads "MMS Minerals Management Service". Below this, there are several sections: "Current Events" with a circular graphic, "Industry Antitrust Ceremony", and "MMS Starts Preparation of New 5-Year OCS Leasing Program". The "MMS Starts Preparation of New 5-Year OCS Leasing Program" section includes a paragraph about the MMS's role in preparing a new 5-year oil and gas leasing plan for the Outer Continental Shelf (OCS). At the bottom of the screenshot, there is a link to "http://www.mms.gov/".

<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.

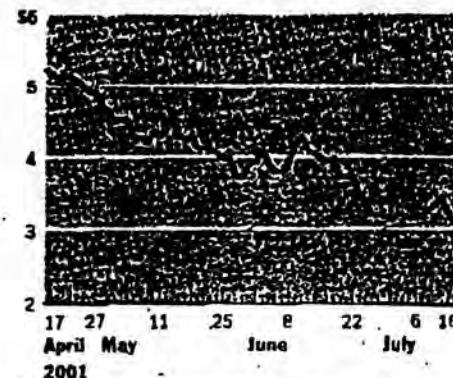
Such a large short position may be hard for some smaller investors to bet against, which only fuels more selling, analysts said.

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.

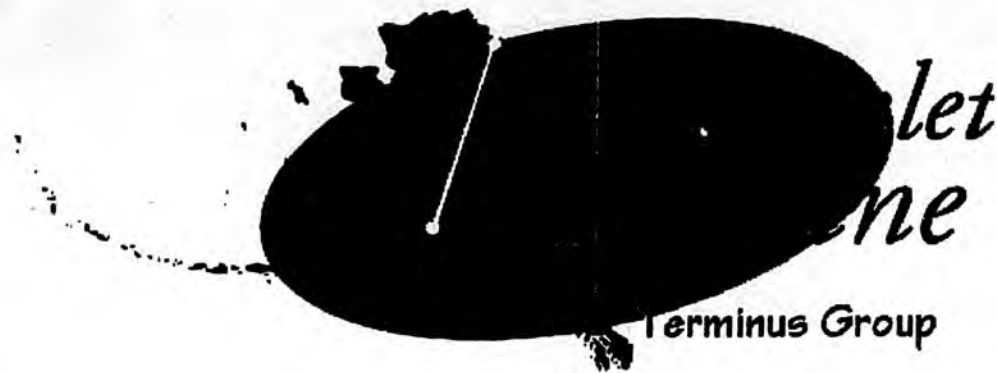
Why Alaskans should support a Cook Inlet Terminus:

- 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**

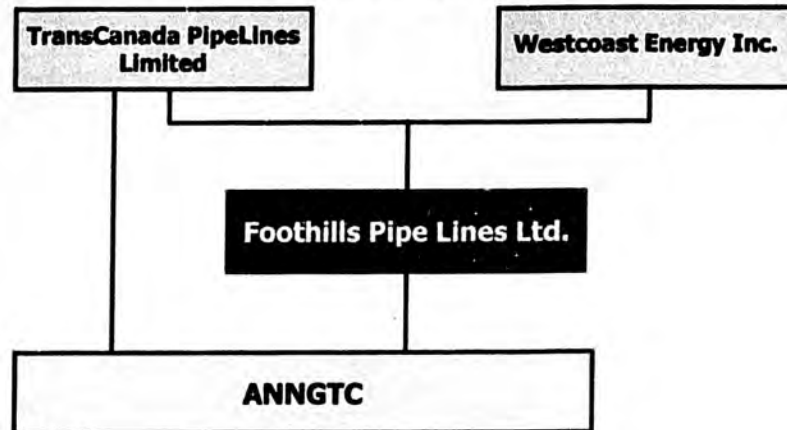
July 18, 2001



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

Earliest Timing

- ◆ ANNGTC/Foothills was selected by the United States and Canada to construct and operate the ANGTS and have secured the following:

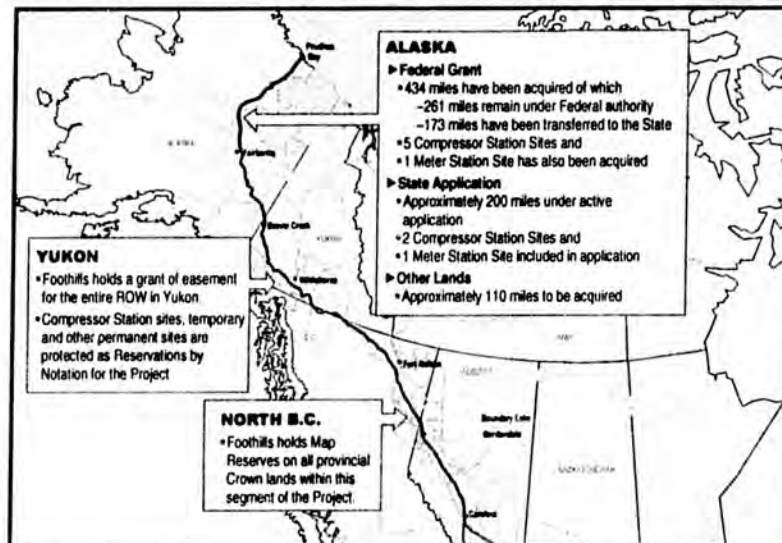
- ▶ Federal Lands ROW
- ▶ Federal ROW on State lands
- ▶ FERC Certificate
- ▶ NEB Certificate
- ▶ US Corps 404 permits
- ▶ Yukon ROW
- ▶ British Columbia Map Reserve

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

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 Mscf 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

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 its 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

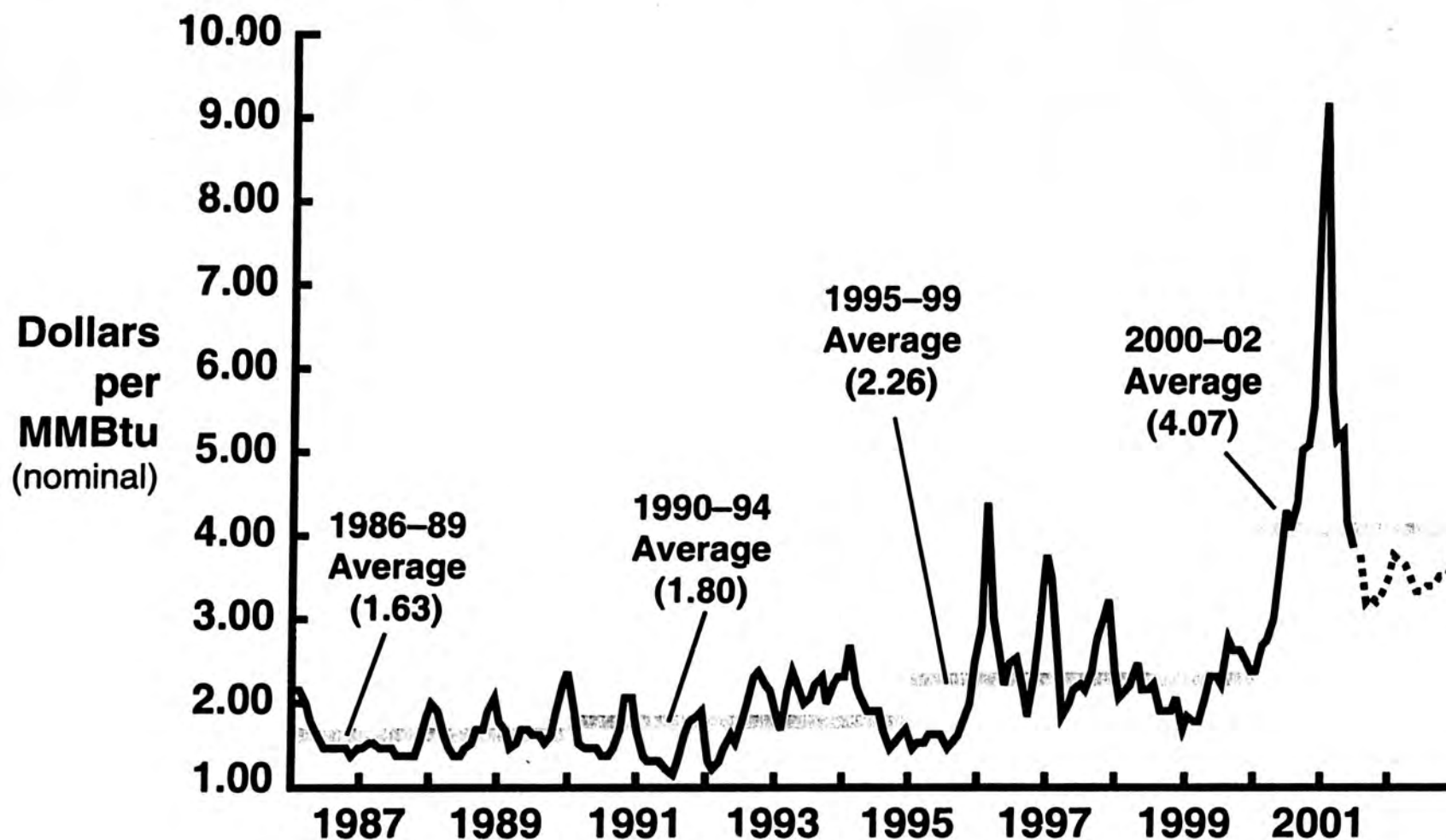


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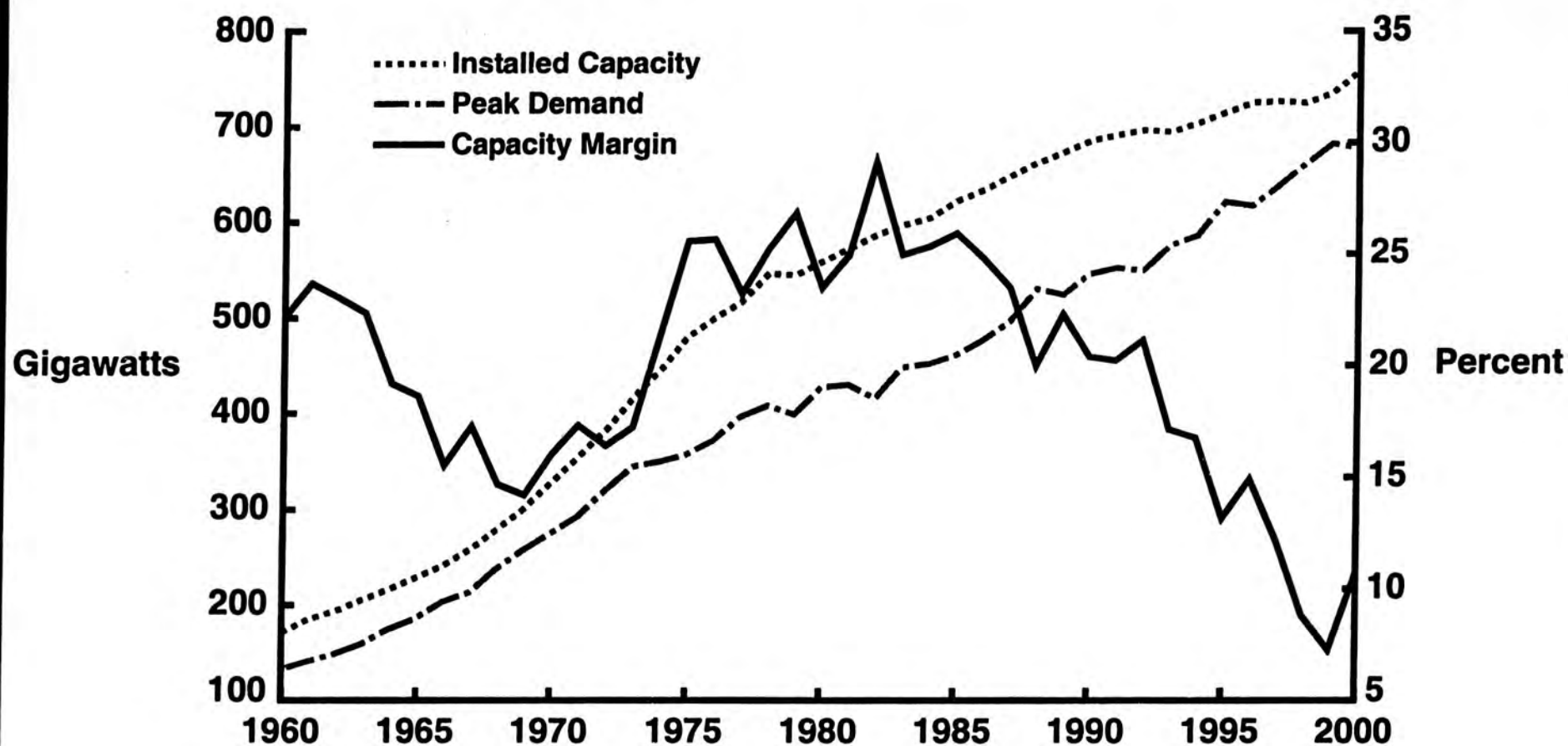
The Surge in North American Gas Prices (Henry Hub Spot Price)



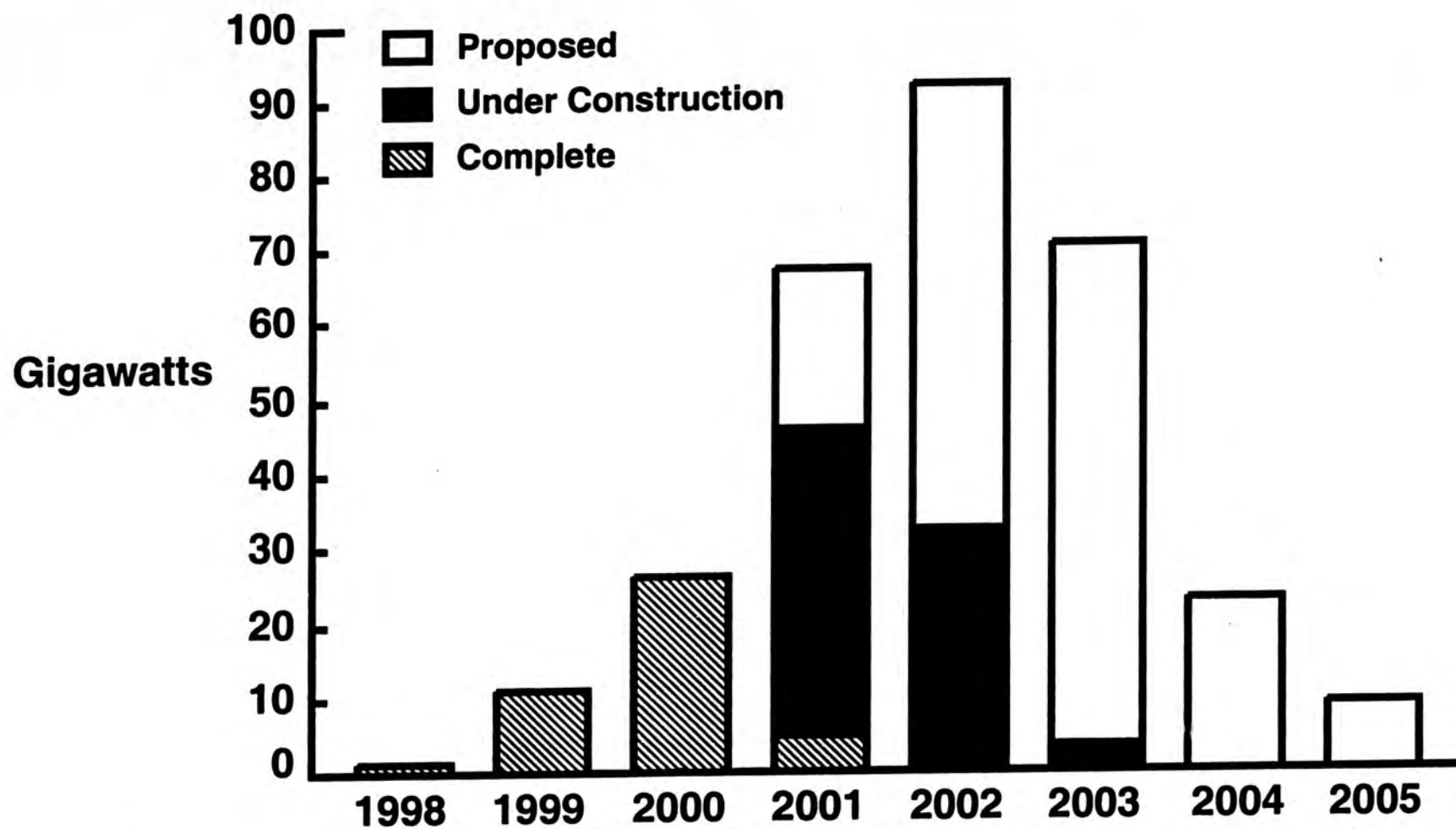
Source: Cambridge Energy Research Associates.
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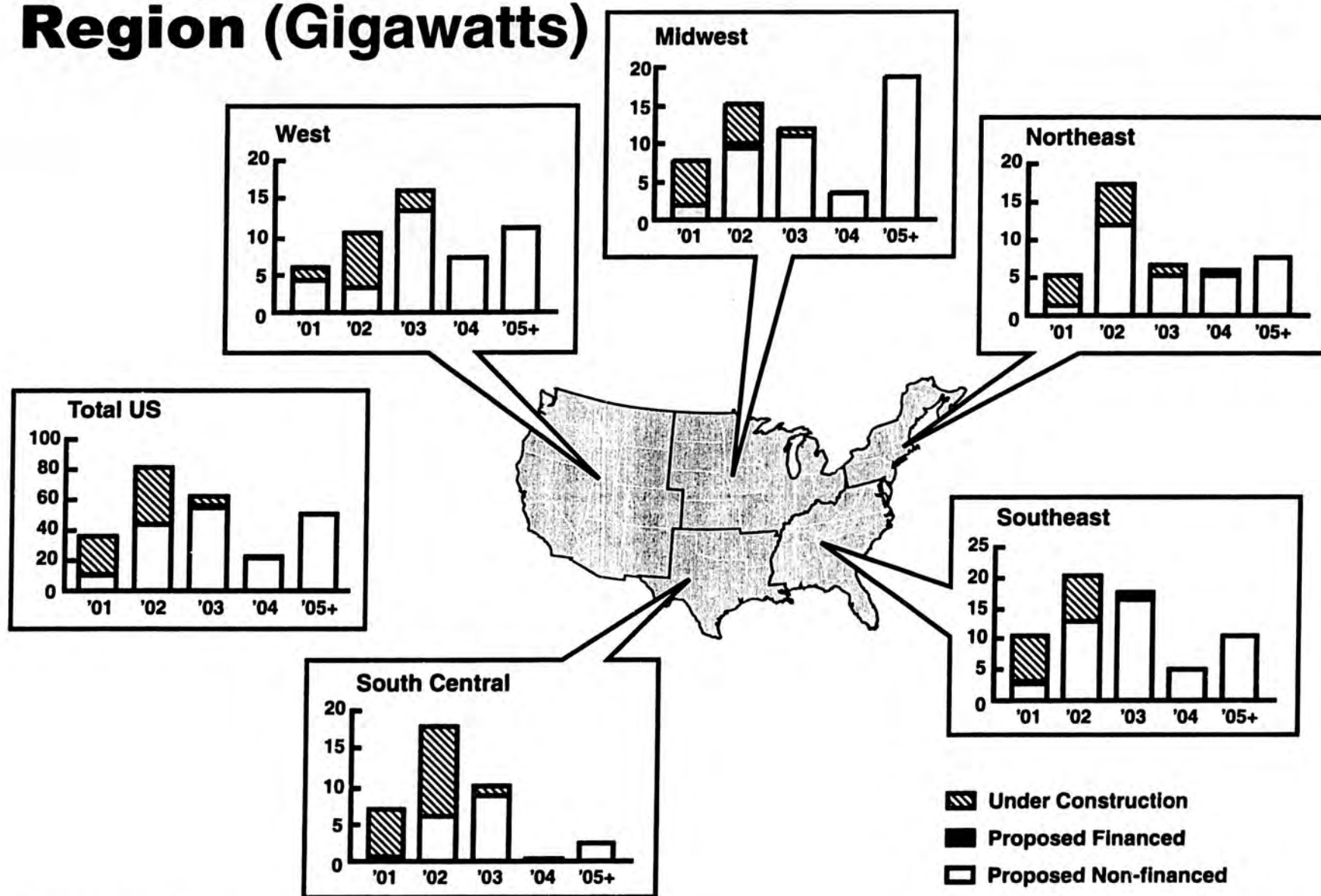
US Installed Capacity, Peak Demand, and Capacity Margin



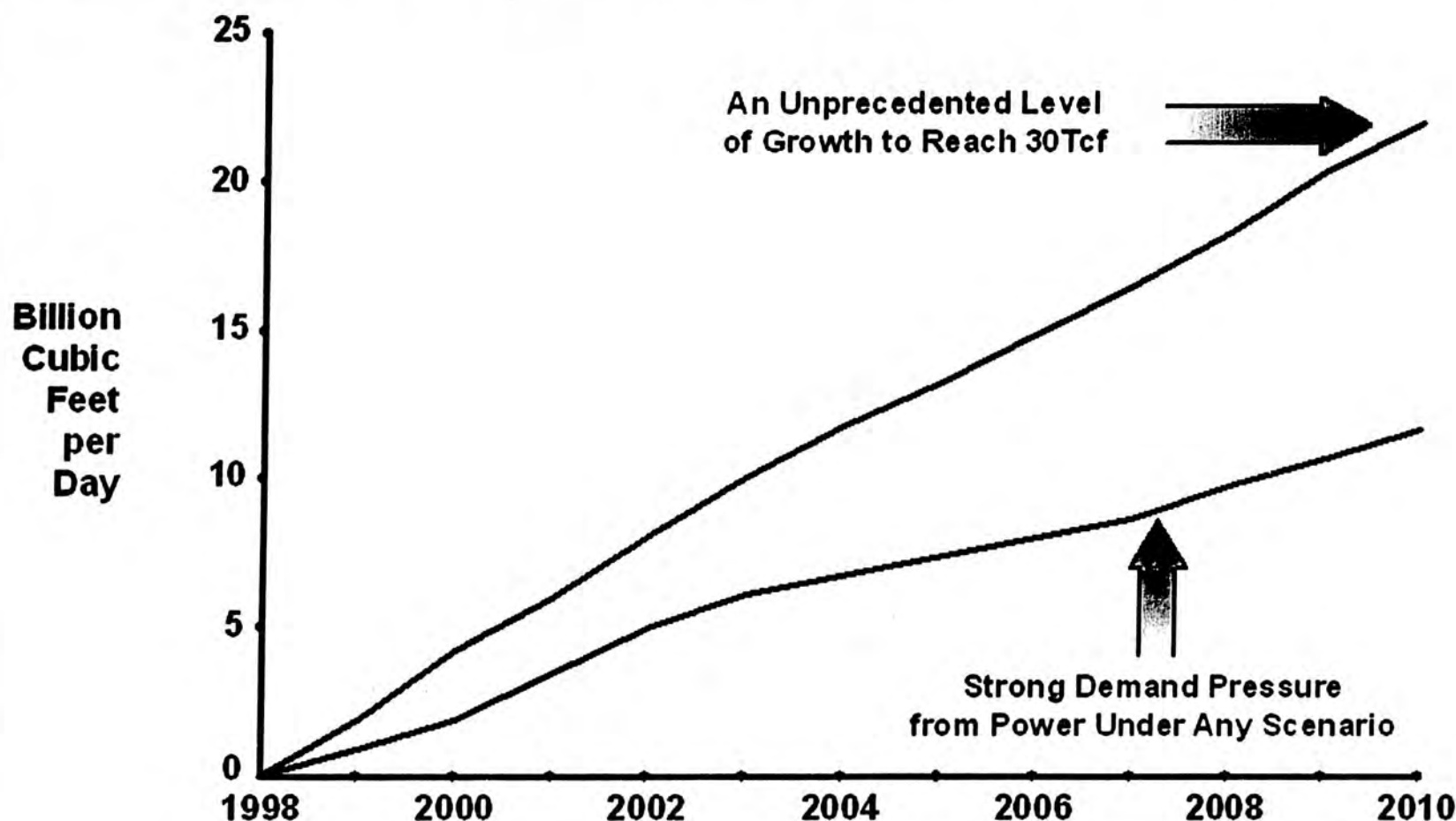
North American Generation Project Status



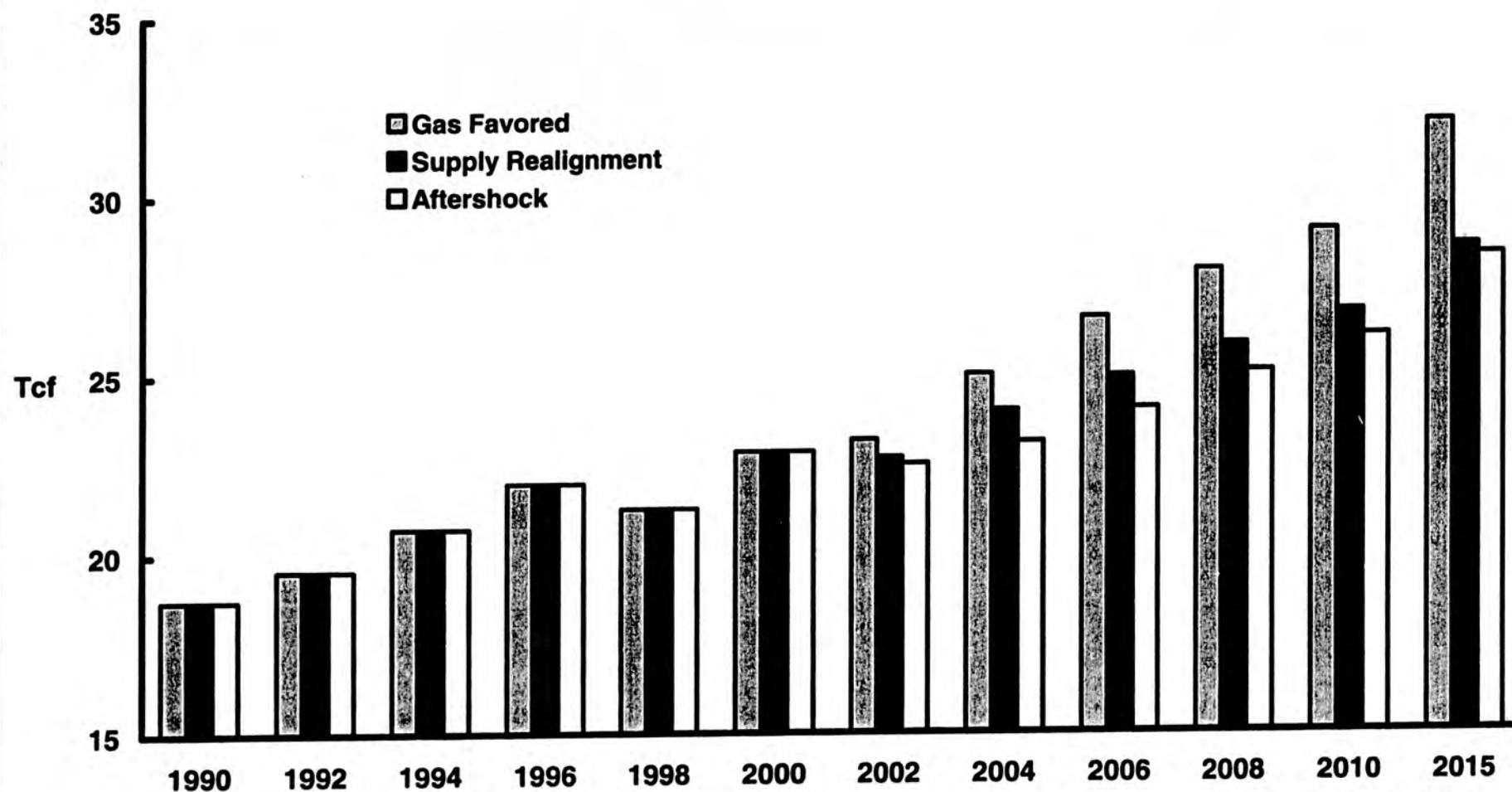
Pressure in the Pipeline: The Potential Gas-fired Power Build by Region (Gigawatts)



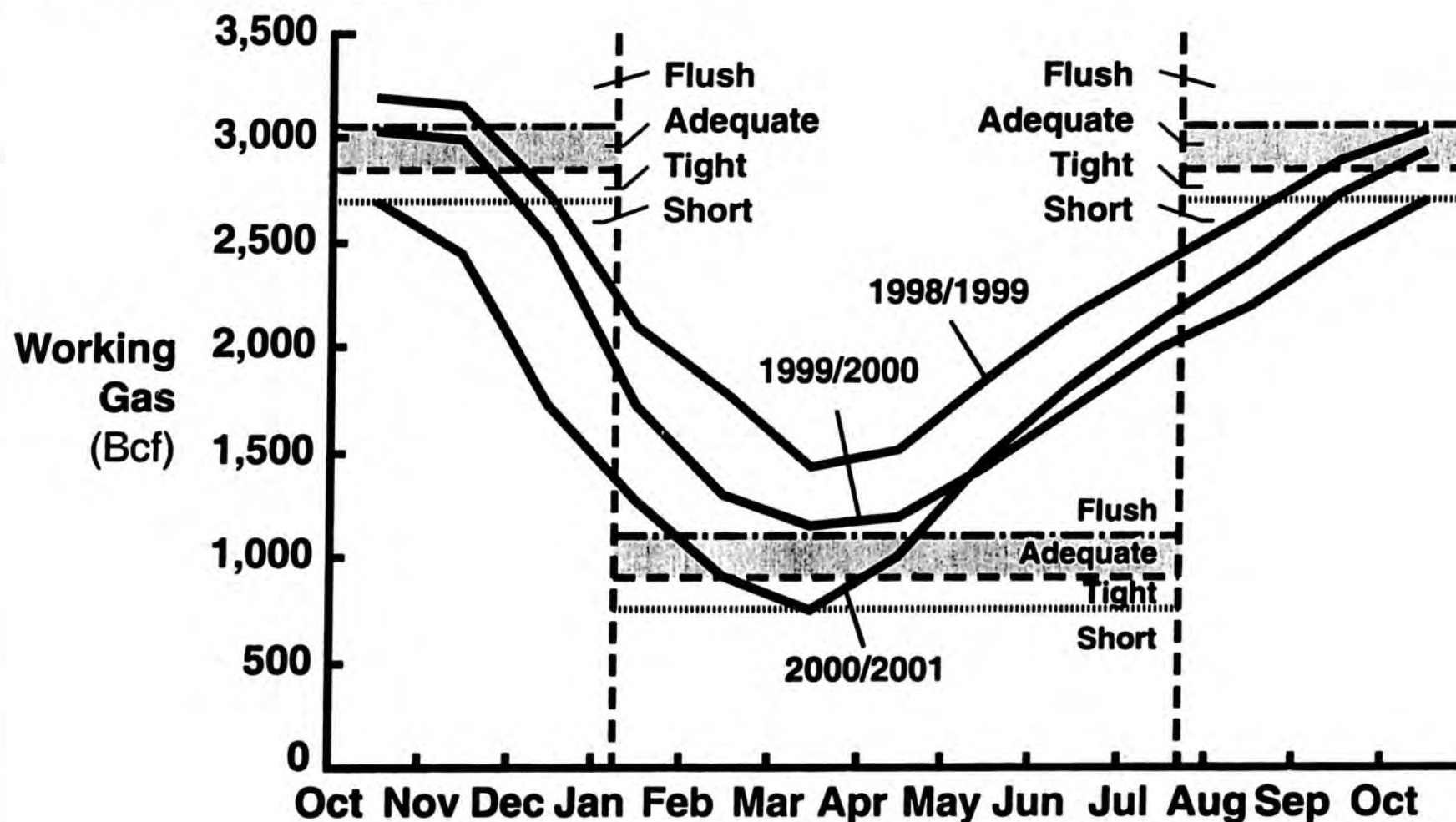
30 Tcf: More Plausible Than Probable The Range of Natural Gas Demand Growth Relative to 1998



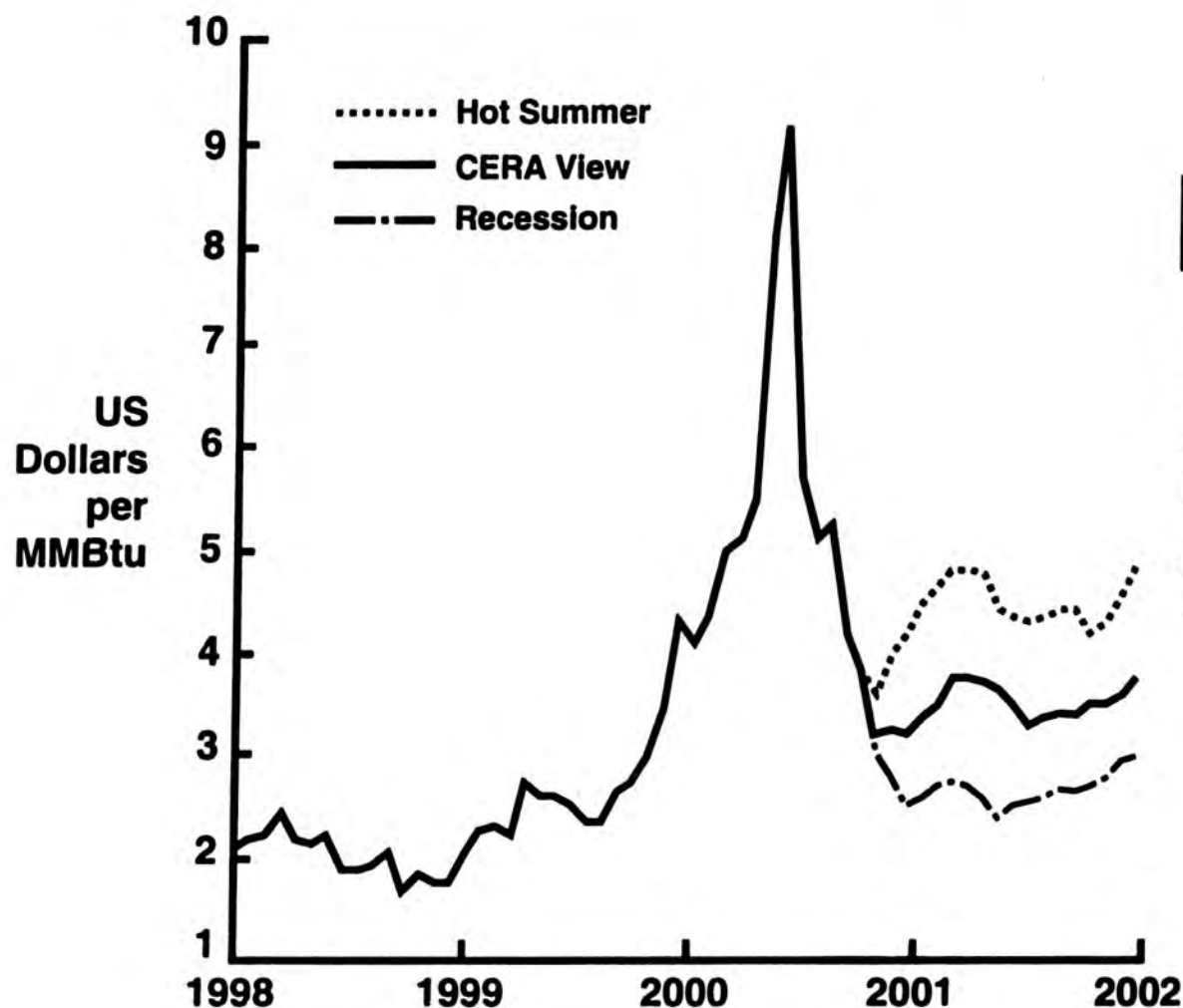
US Lower-48 Natural Gas Demand



The Storage Cushion Deflates: Supply Declines Drive Down Inventories



Henry Hub Price Projections



2000 Average	2001 Average	2002 Average
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Hot Summer:

\$4.23 \$4.91 \$4.46

CERA View:

\$4.23 \$4.45 \$3.53

Recession:

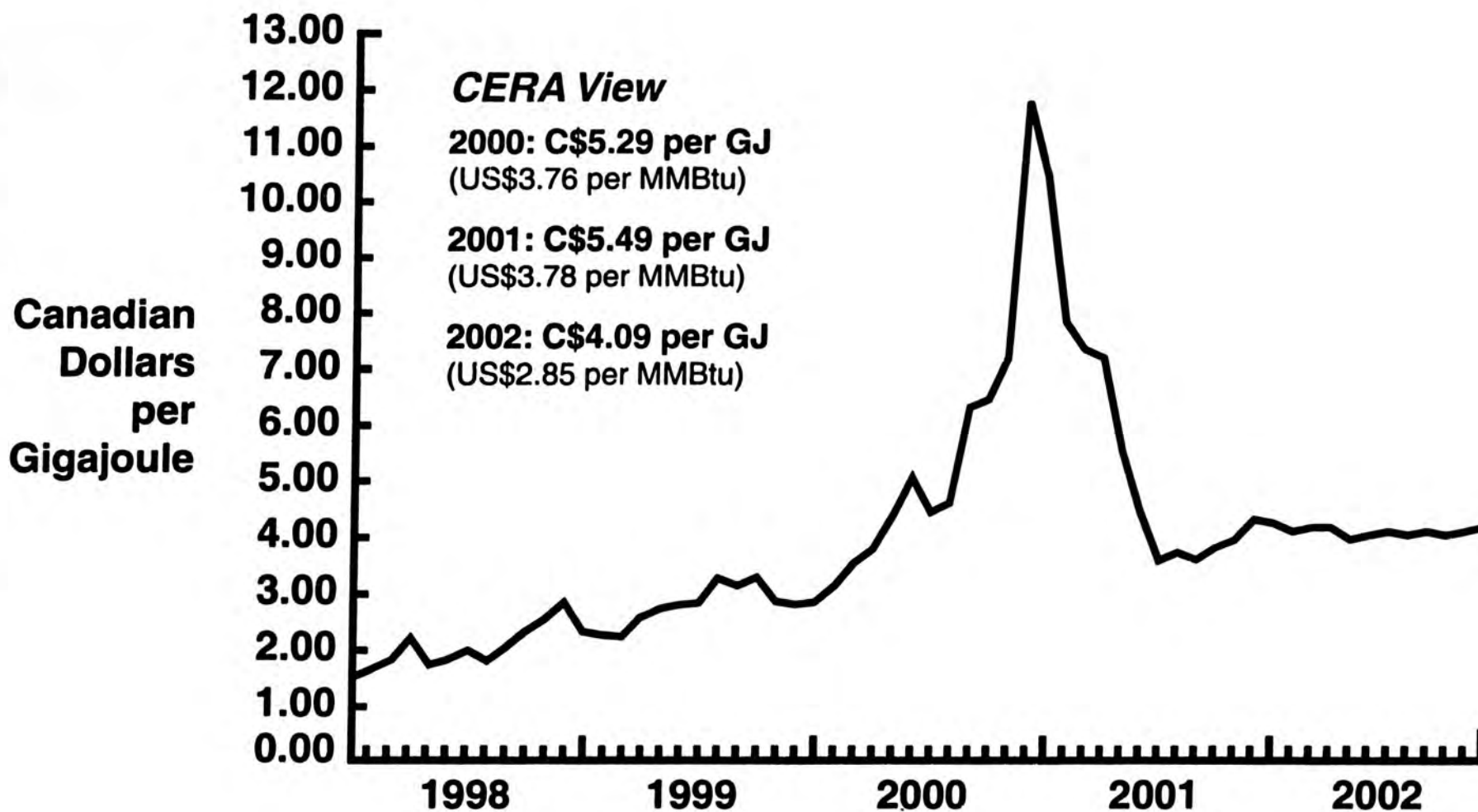
\$4.23 \$4.13 \$2.68



Source: Cambridge Energy Research Associates.
 90306-14
 070501

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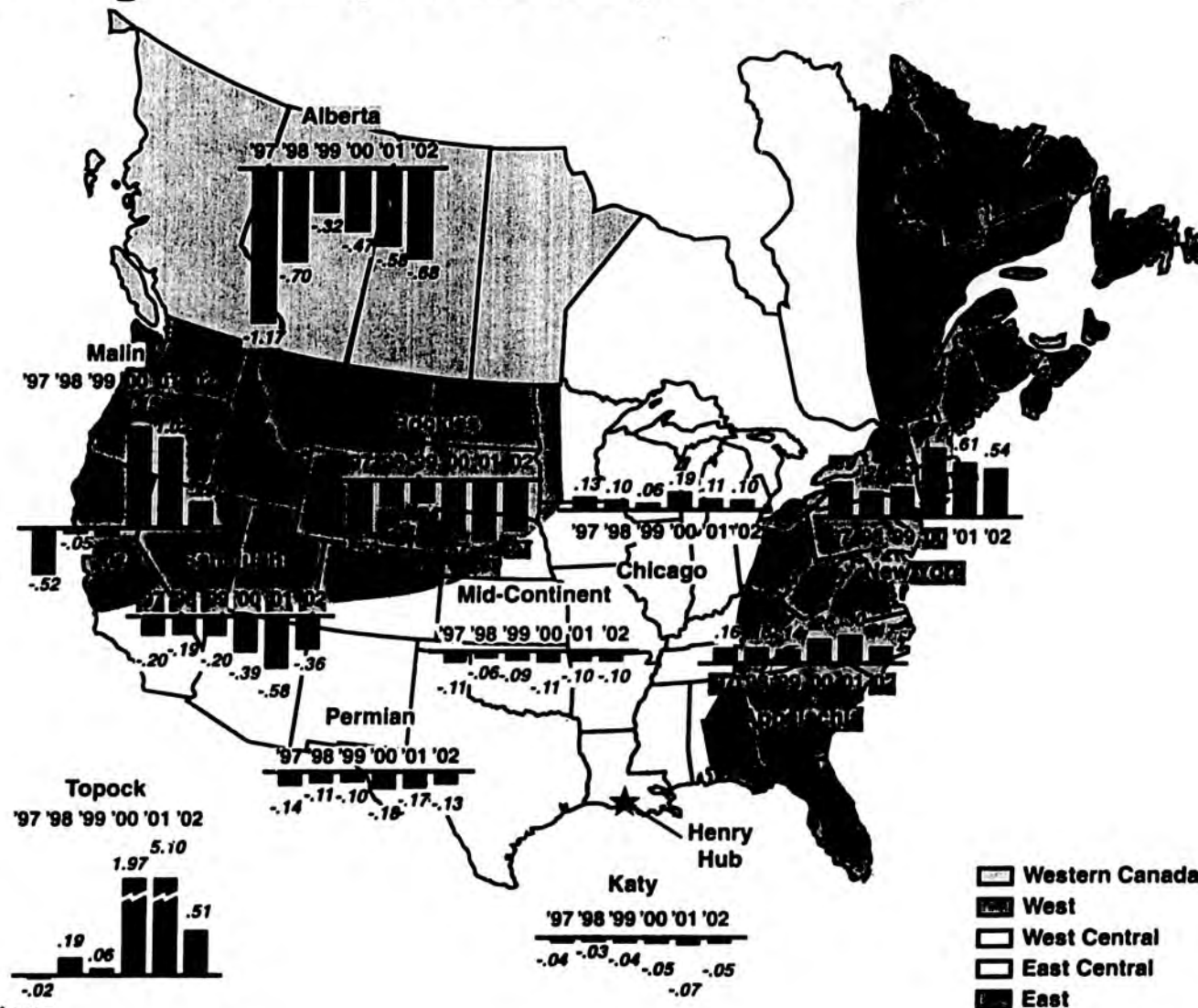
AECO Spot Gas Price Outlook



Source: Cambridge Energy Research Associates.
90119-4
0712

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



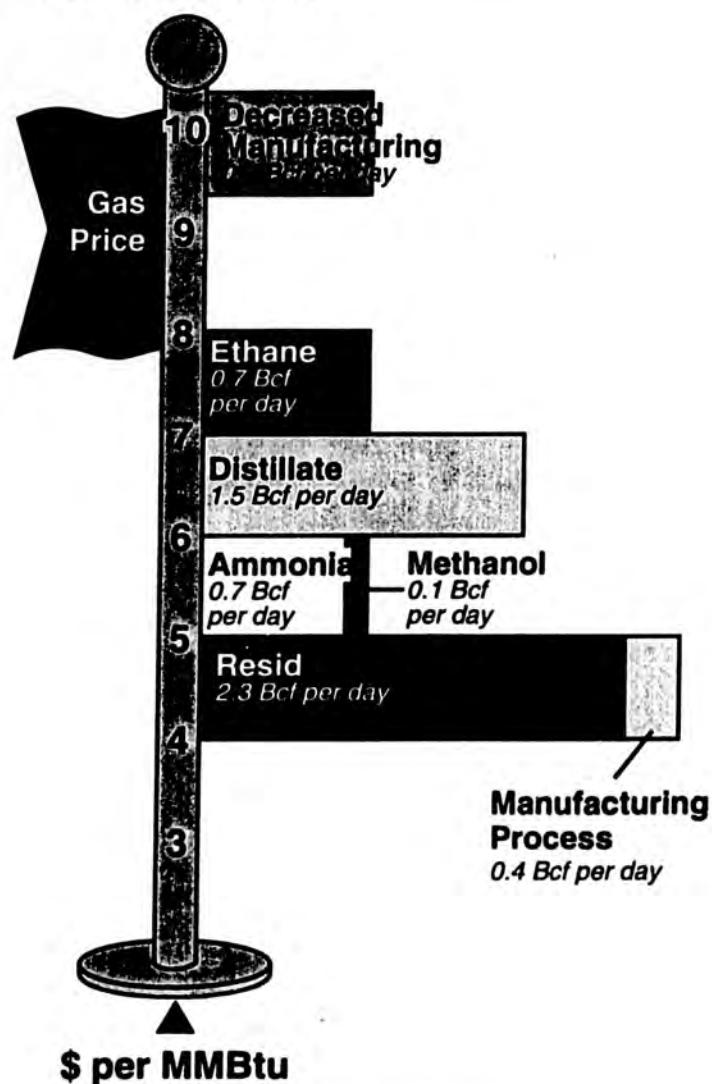
Note: Supply Realignment case.

Source: Cambridge Energy Research Associates.
90341-1
0712

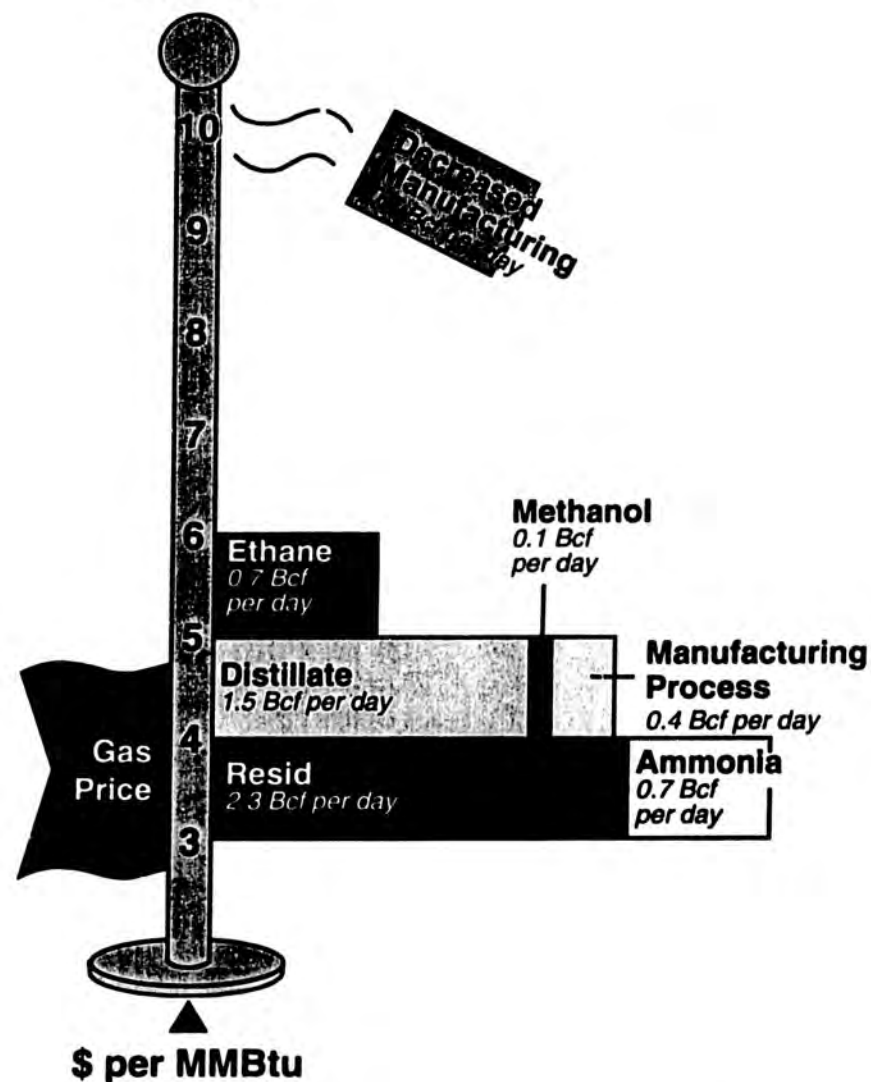
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Shifts in Competitive Markets

December 2000



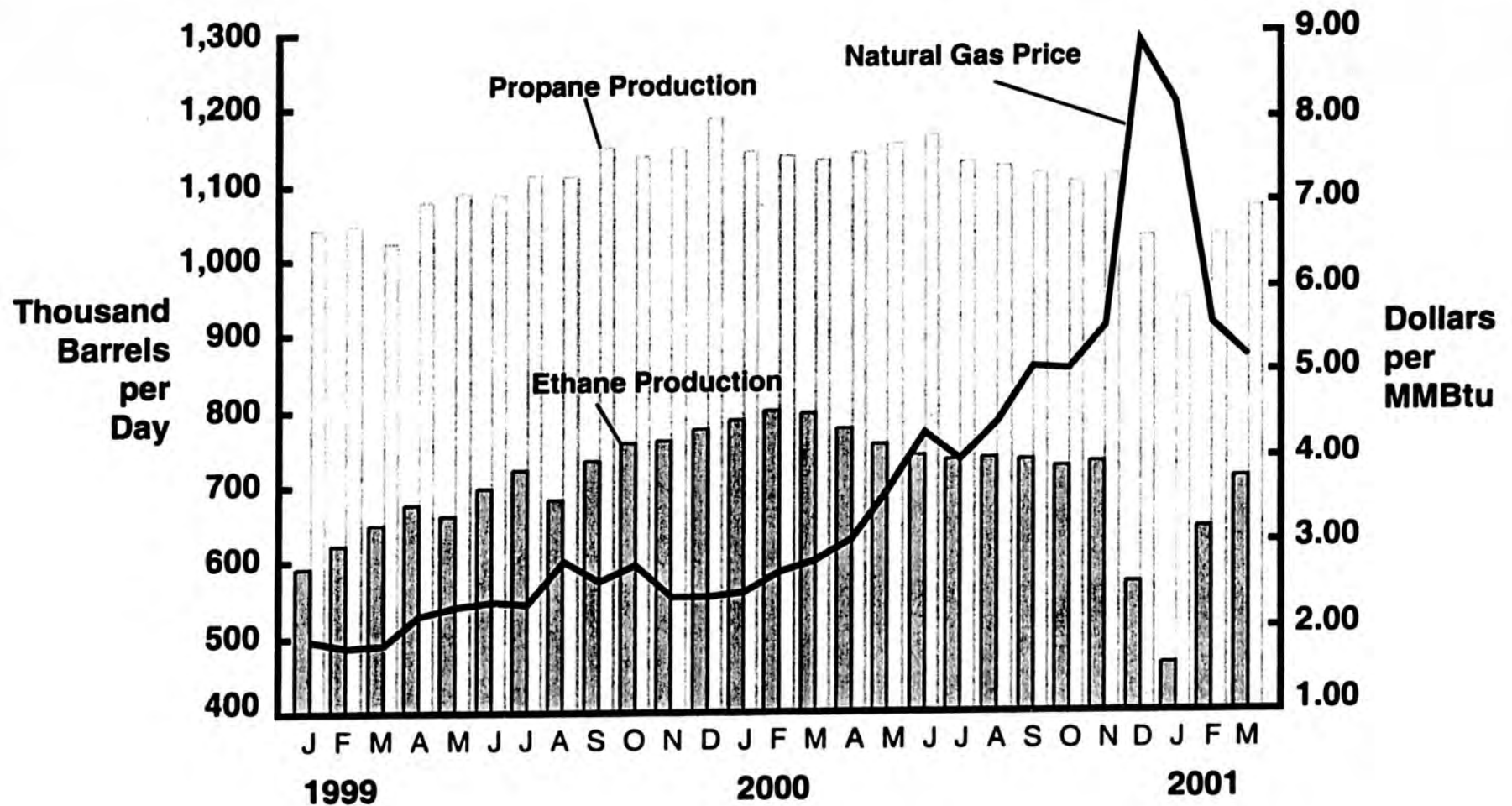
Q3 2001



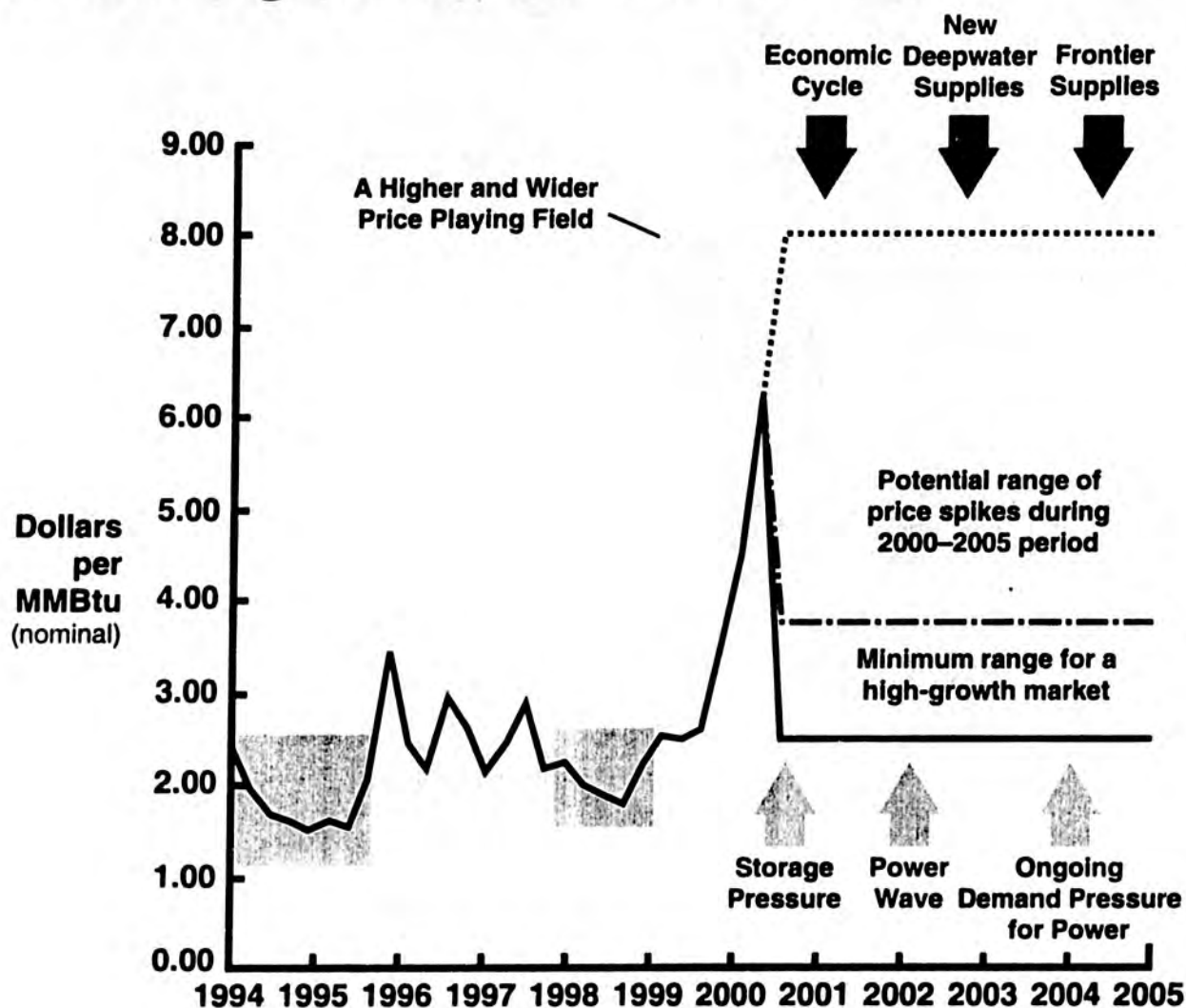
Source: Cambridge Energy Research Associates.
10118-2
0622

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US Gas Liquids Production versus Natural Gas Price



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

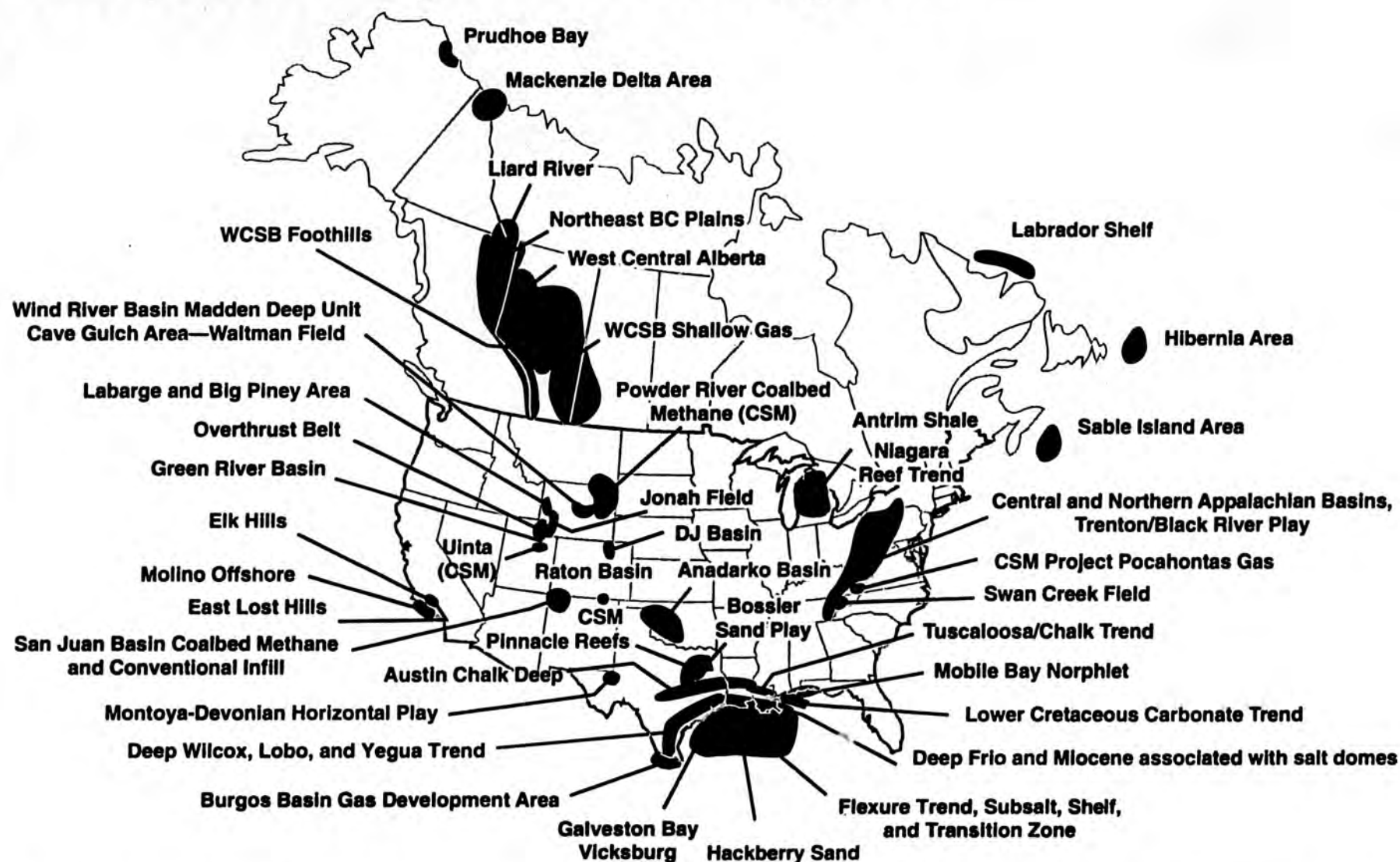


Source: Cambridge Energy Research Associates.
00315-4
0220

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

AlaskaStateLegislature_071501_nag

Major North American Gas Exploration and Development Hotspots

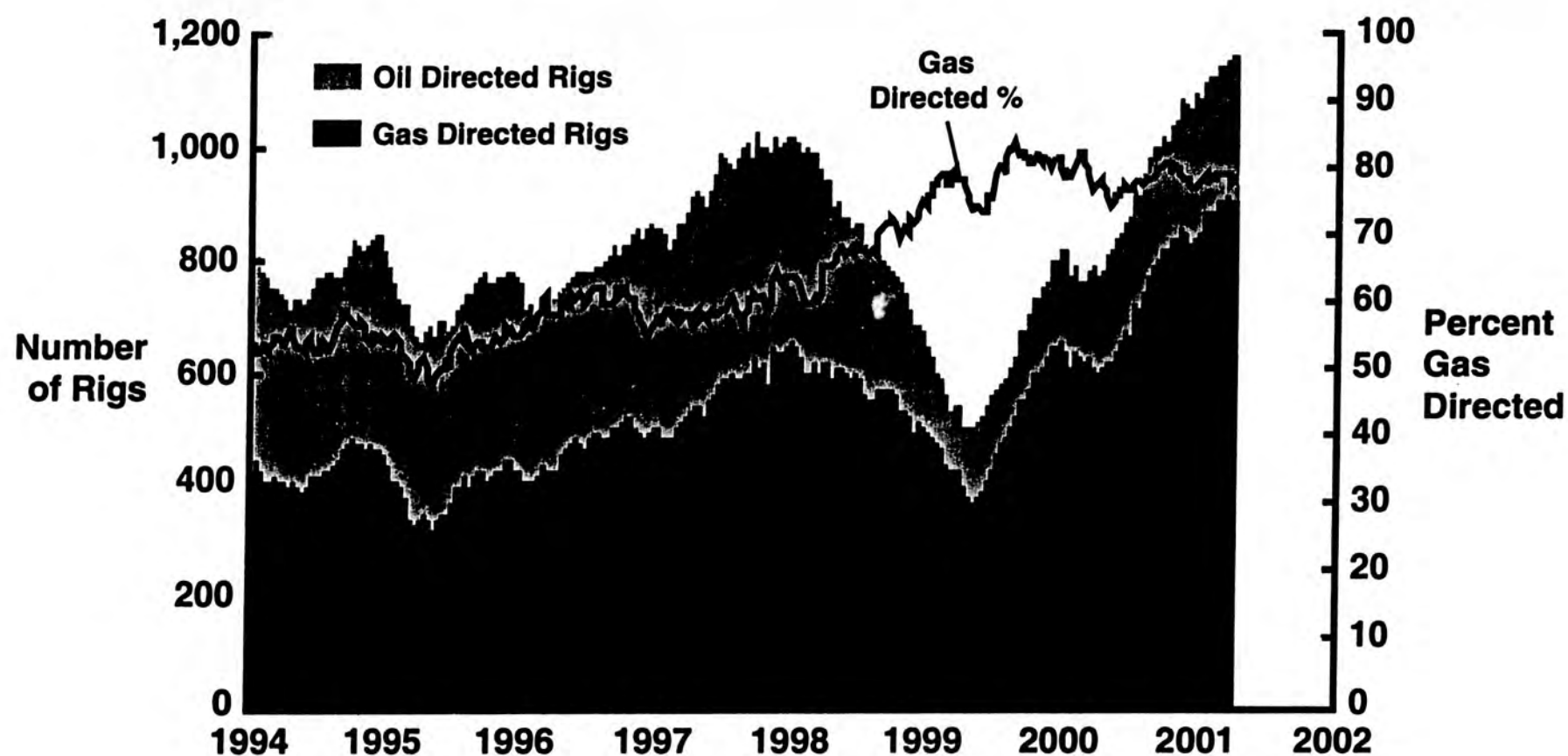


CERA

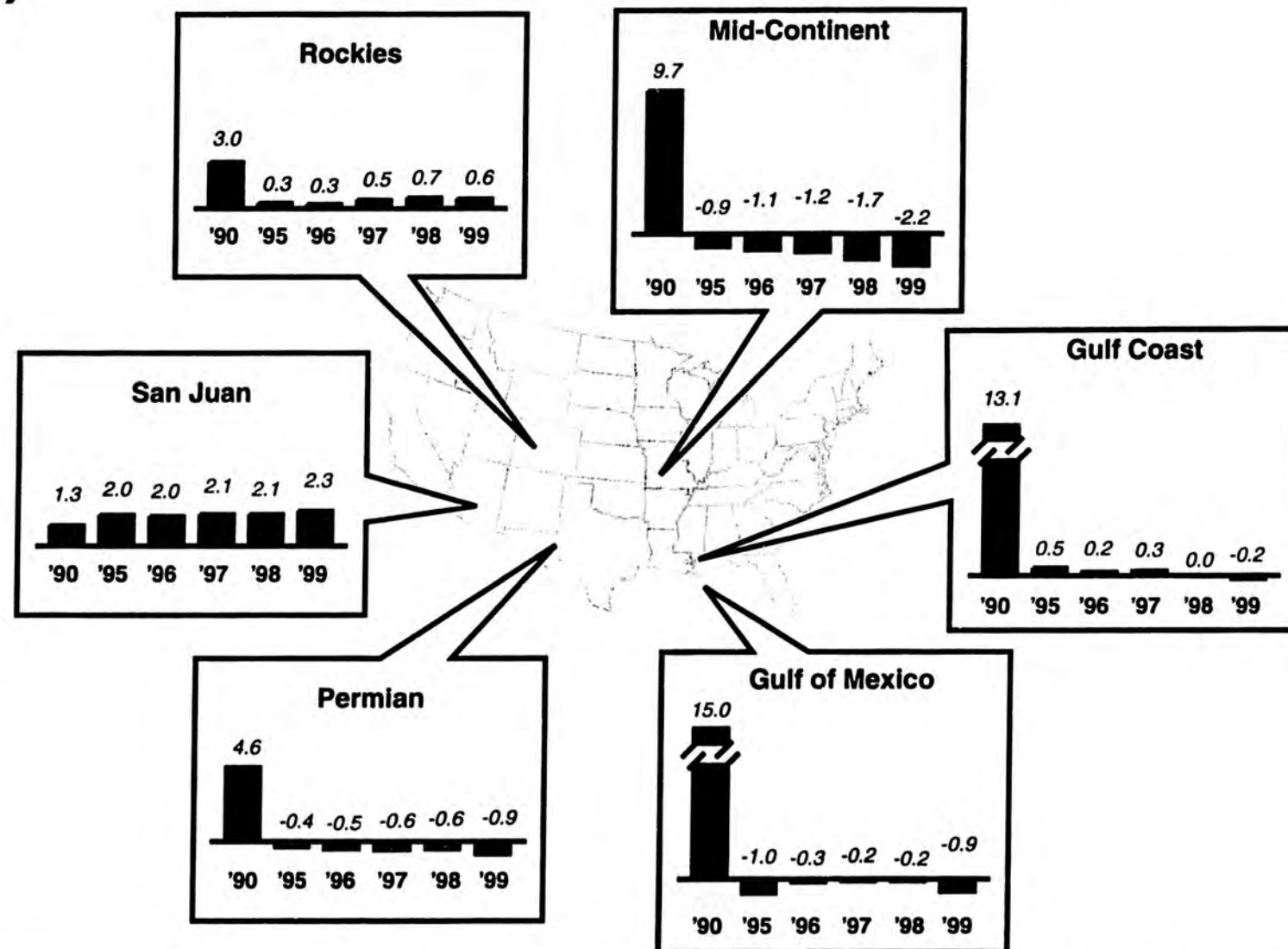
Source: Cambridge Energy Research Associates.
Updated April 2001
90523-27

AlaskaStateLegislature_071501_nag

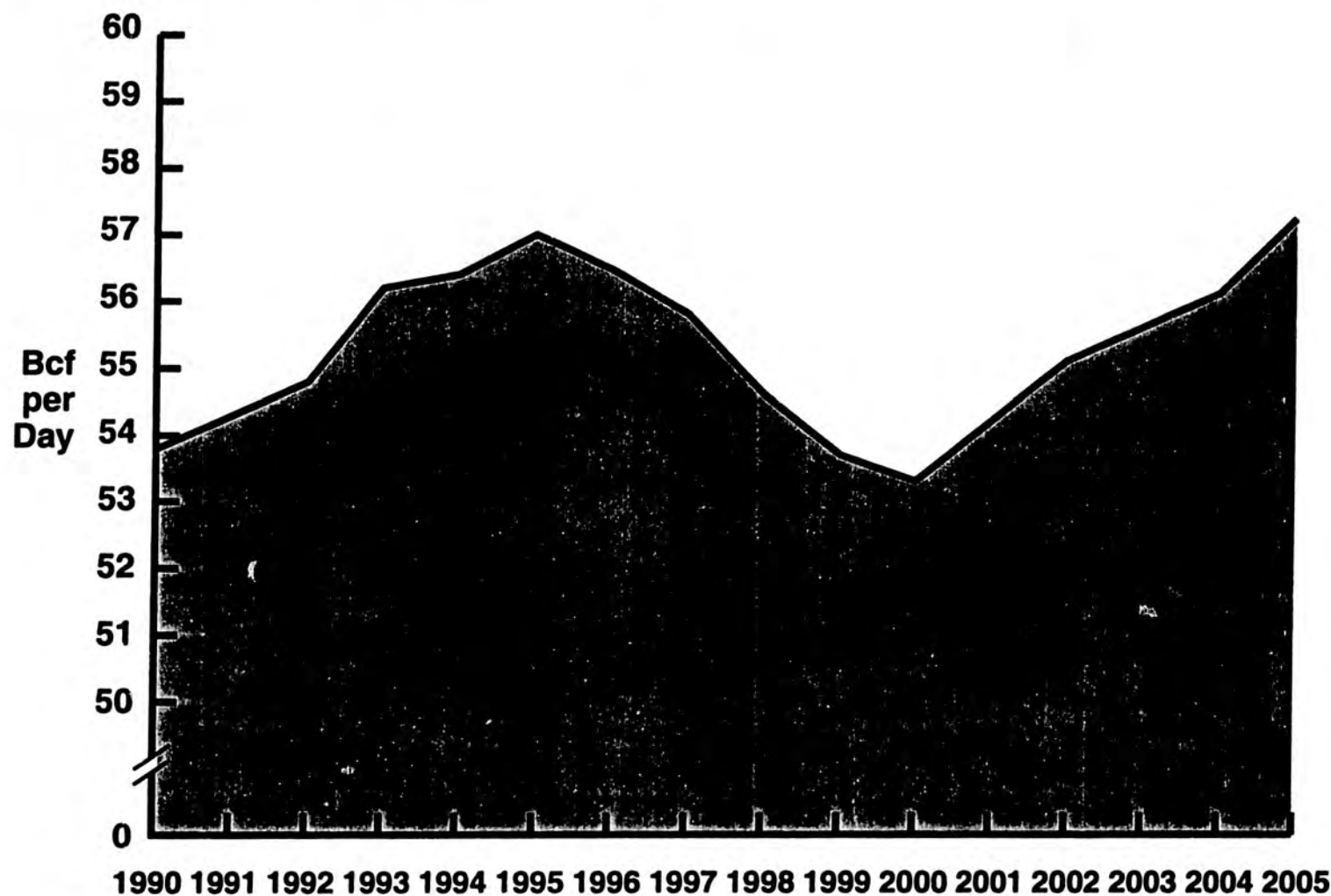
US Rig Fleet and Gas-directed Drilling



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



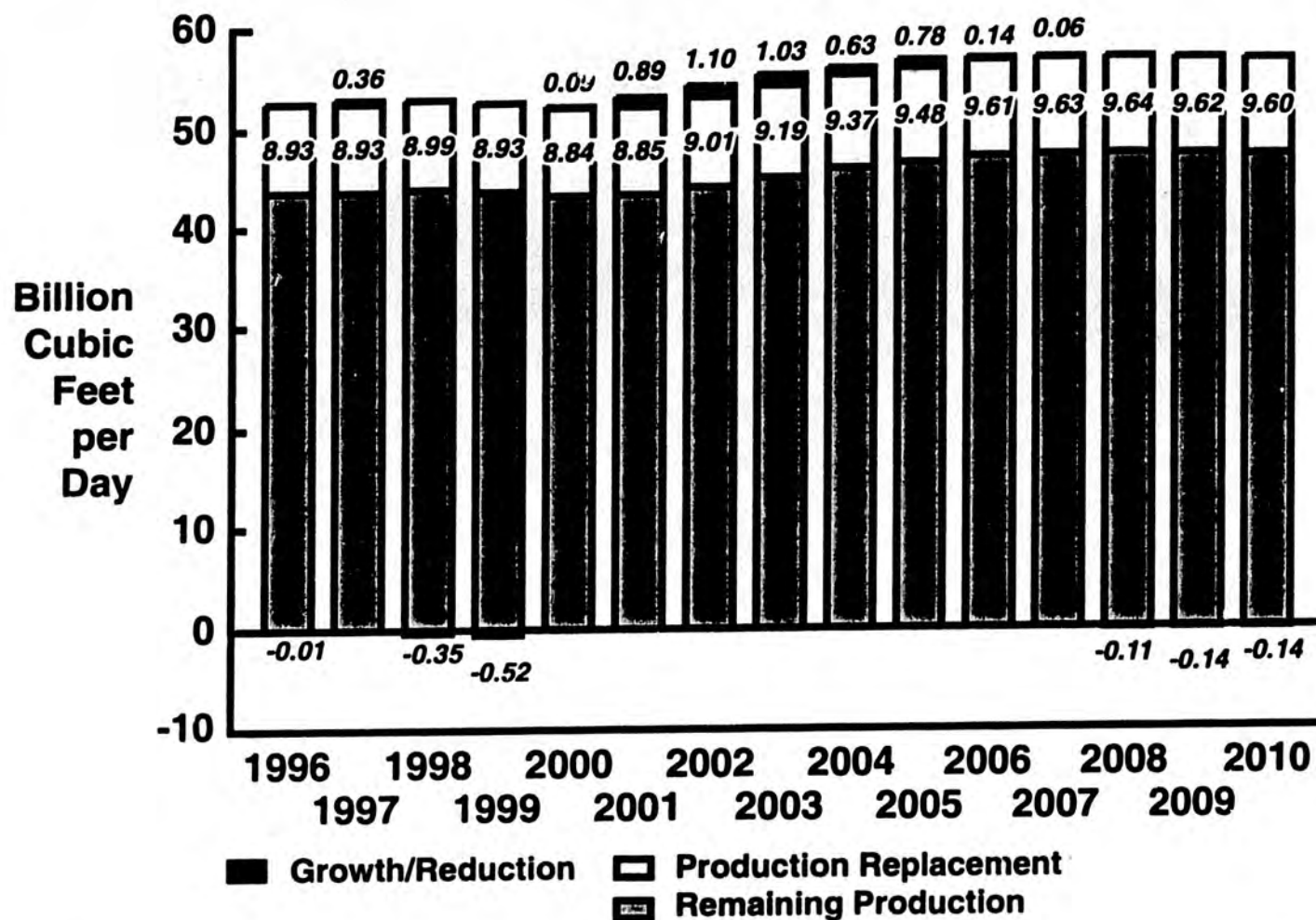
US Lower-48 Average Annual Wet Gas Productive Capacity



Source: Cambridge Energy Research Associates.
Updated June 2001
10530-3

AlaskaStateLegislature_071501_nag

North American Onshore Gas Production*

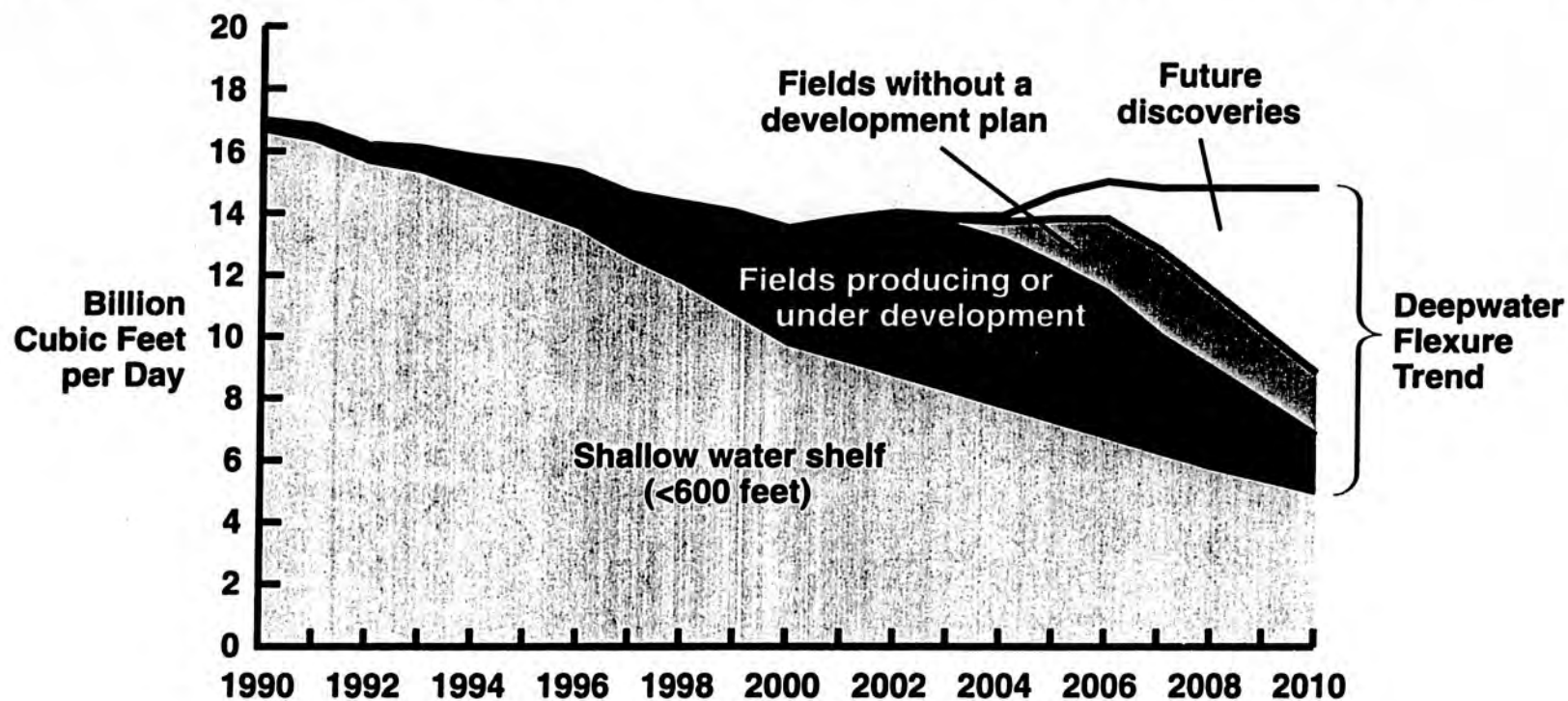


Source: Cambridge Energy Research Associates.

*Gulf Coast, Permian & Mid-Continent, Rockies and San Juan, Western Canada
10328-6

AlaskaStateLegislature_071501_nag

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.

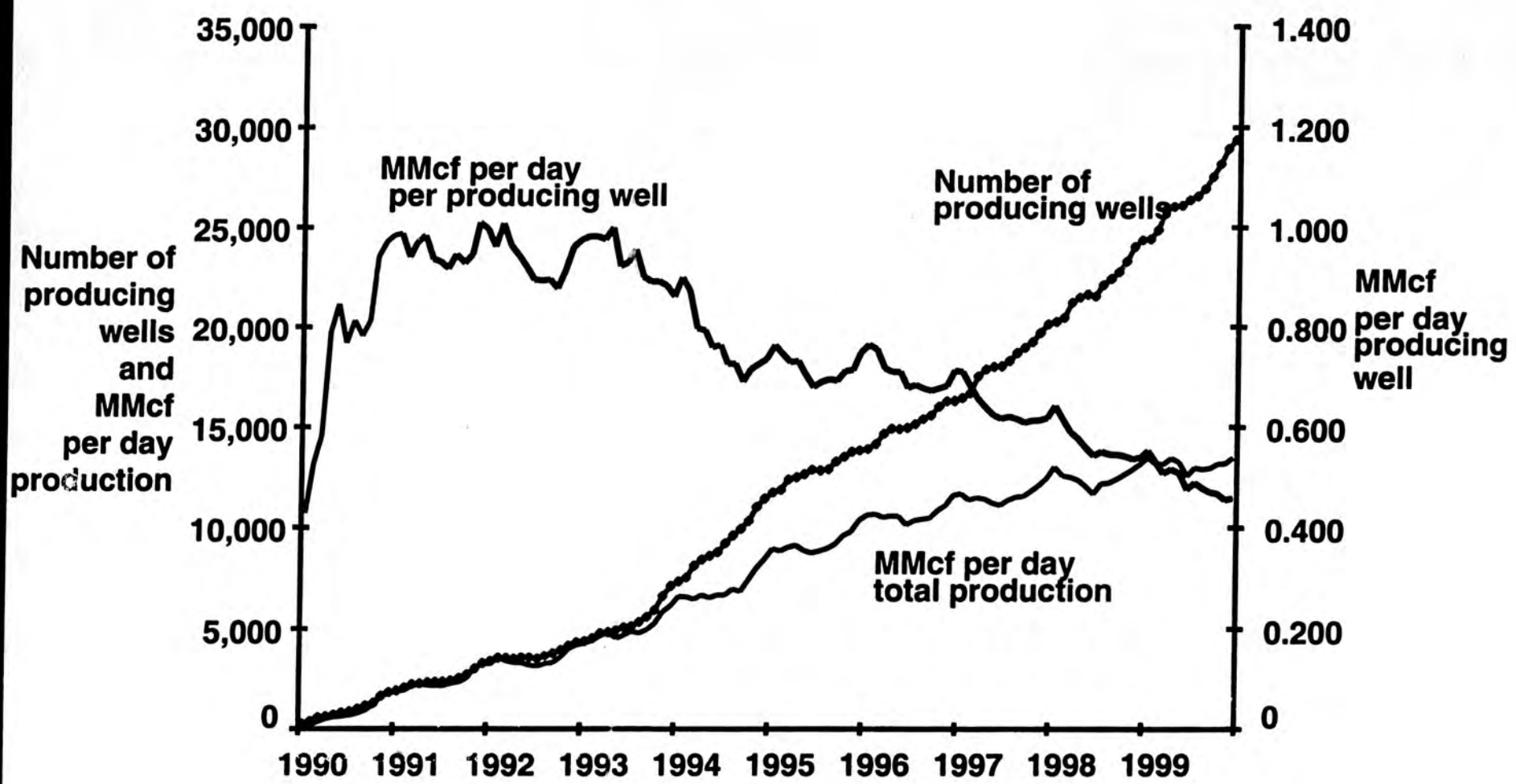
* Includes Louisiana and Texas only.

Updated June 2001

10530-4

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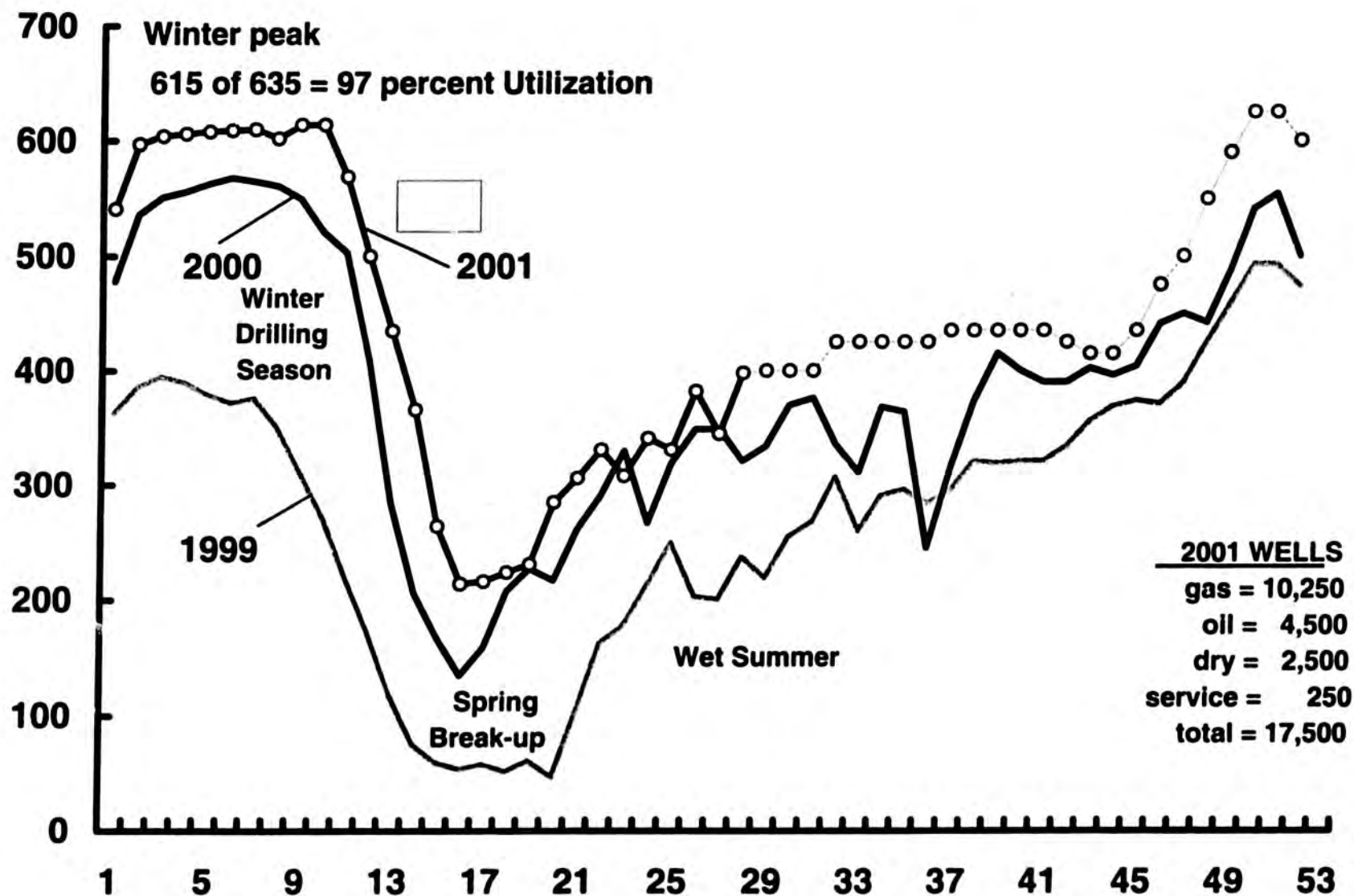
WCSB Wells and Average Production



Source: Cambridge Energy Research Associates.

AlaskaStateLegislature_071501_nag

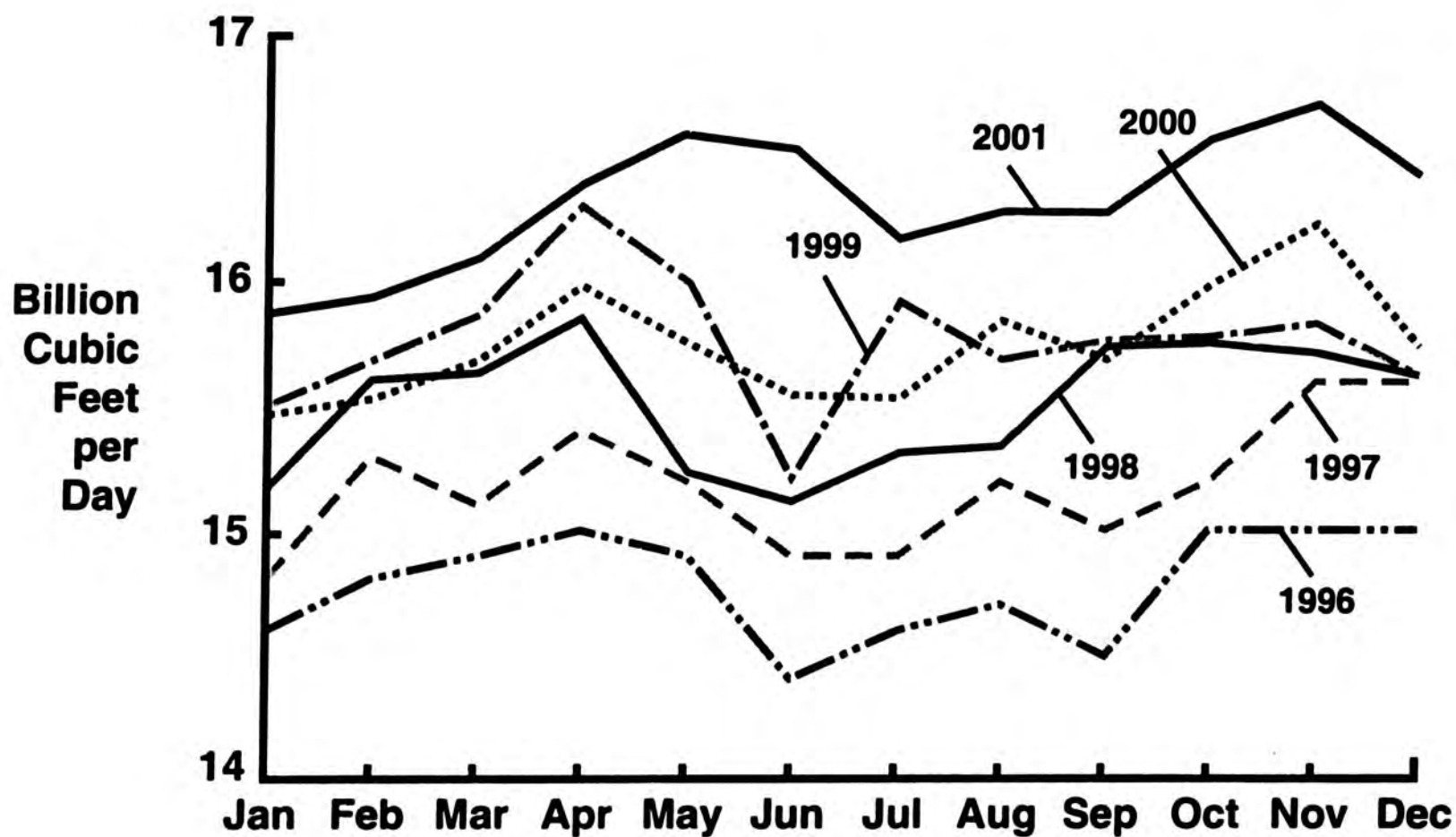
WCSB Active Rig Count 1999-2001



Source: Cambridge Energy Research Associates.
July 2001

AlaskaStateLegislature_071501_nag

Western Canadian Gas Supply

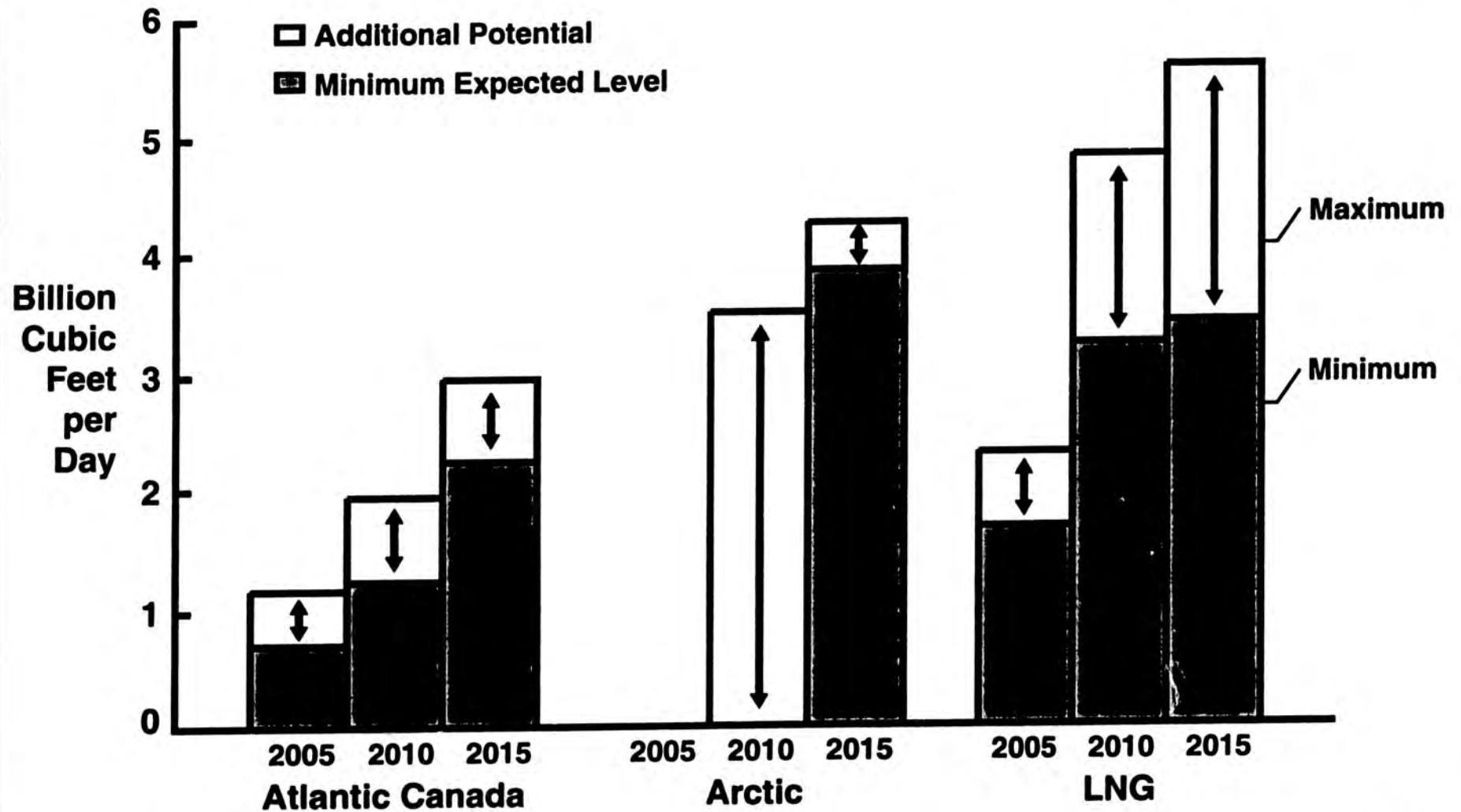


CERA

Source: Cambridge Energy Research Associates.
90920-5
061801

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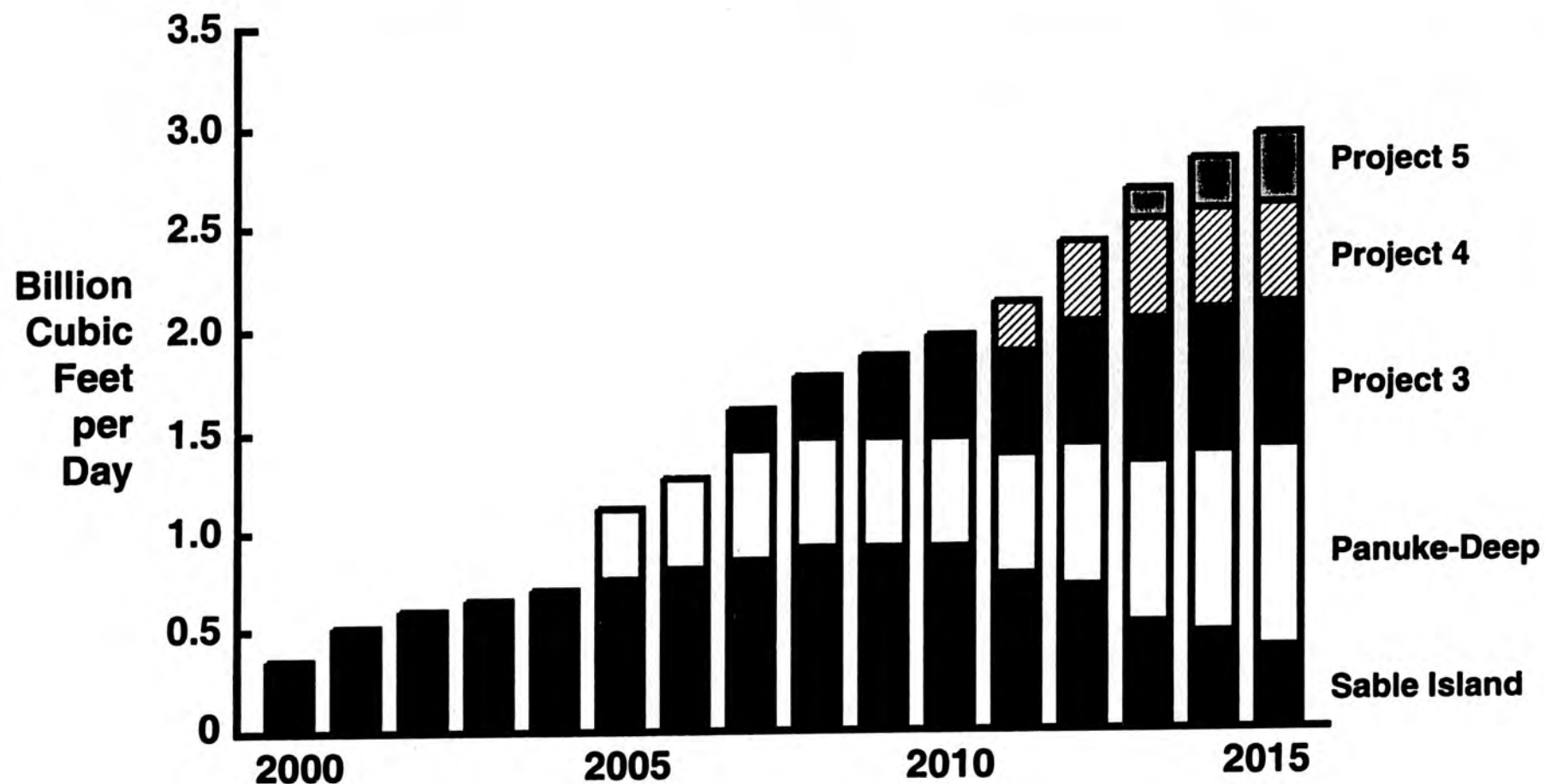
The Range of Production Levels from Frontier Areas



Source: Cambridge Energy Research Associates.
00315-3

AlaskaStateLegislature_071501_nag

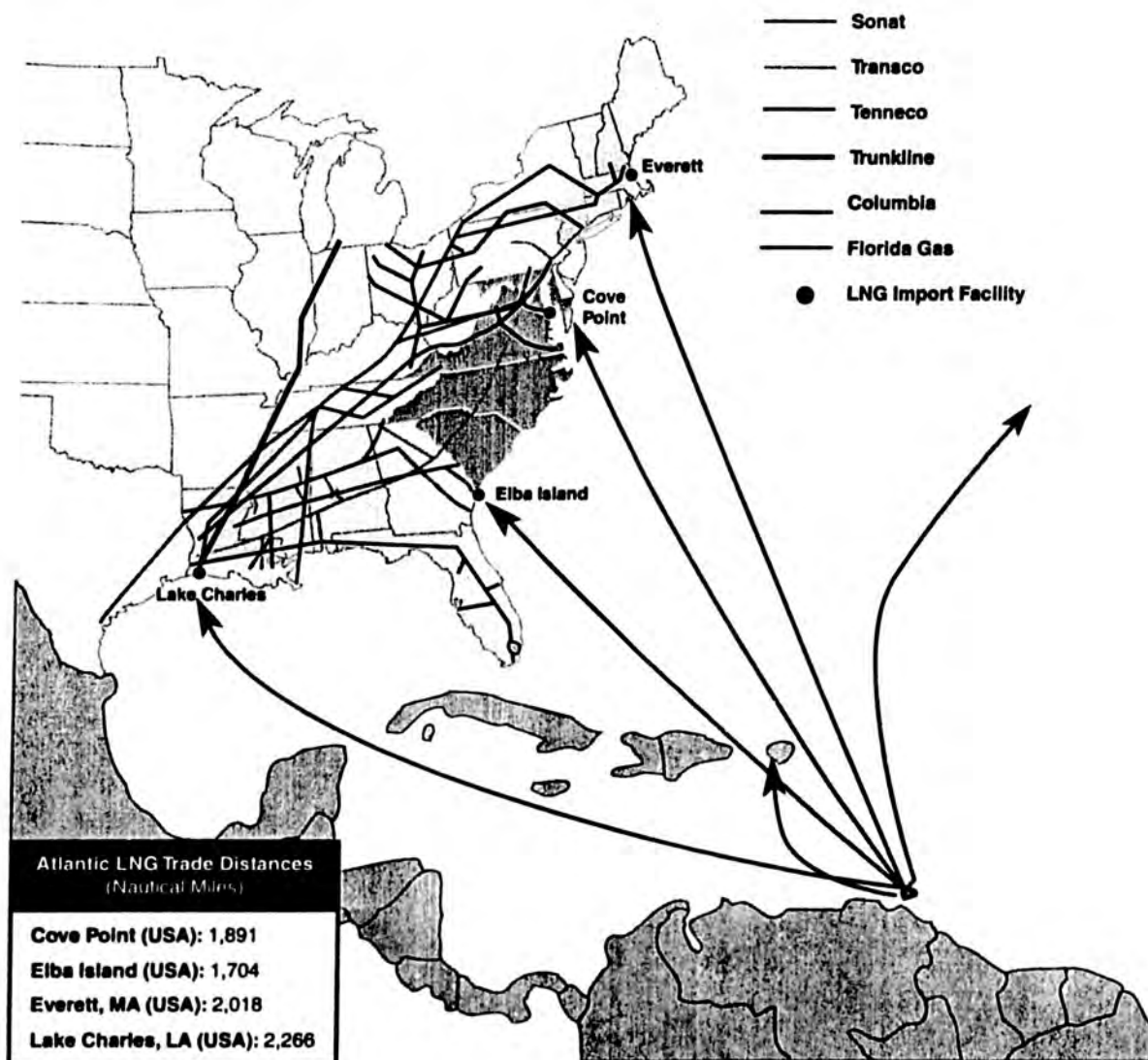
Scotian Shelf Supply Build



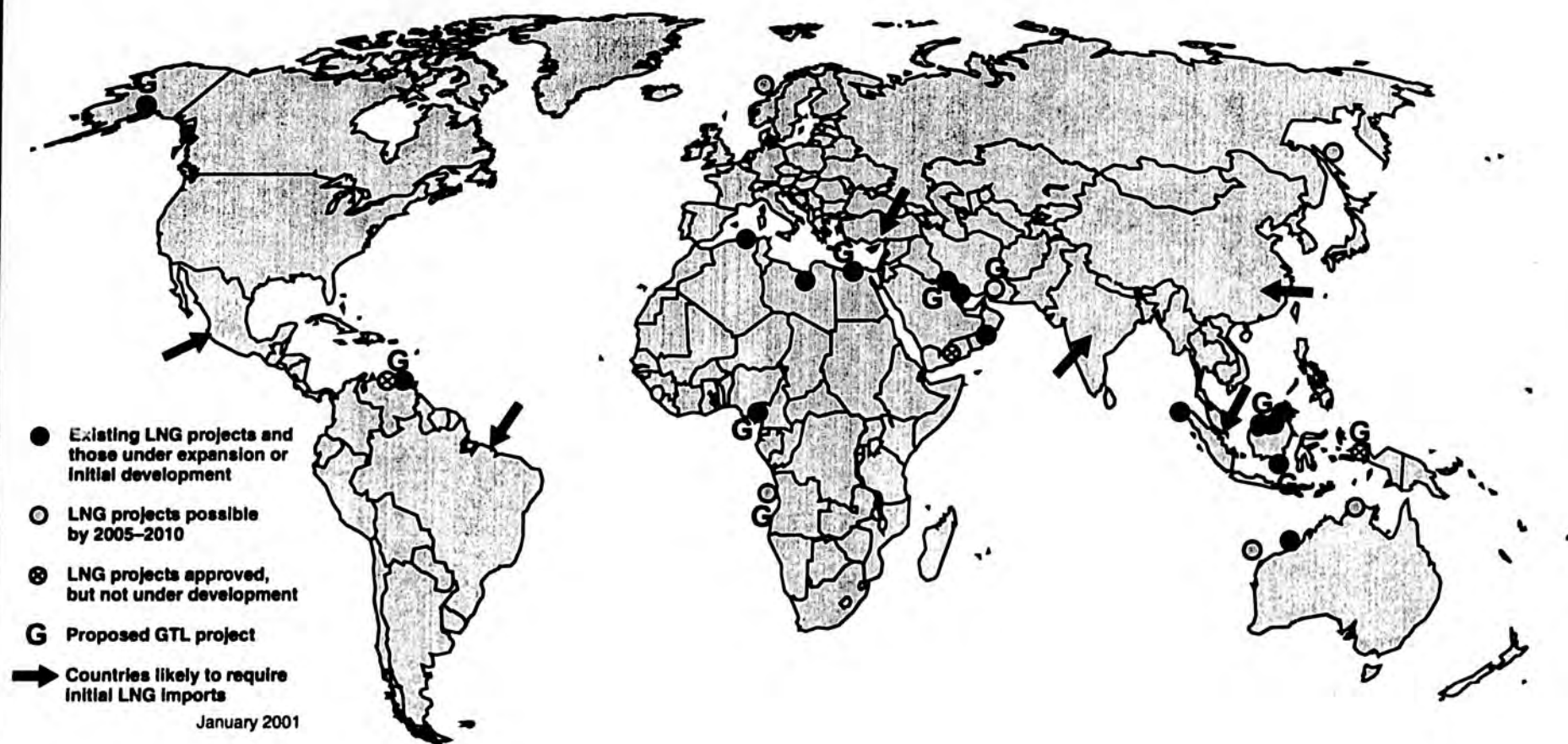
Source: Cambridge Energy Research Associates.
00917-16
041001

AlaskaStateLegislature_071501_nag

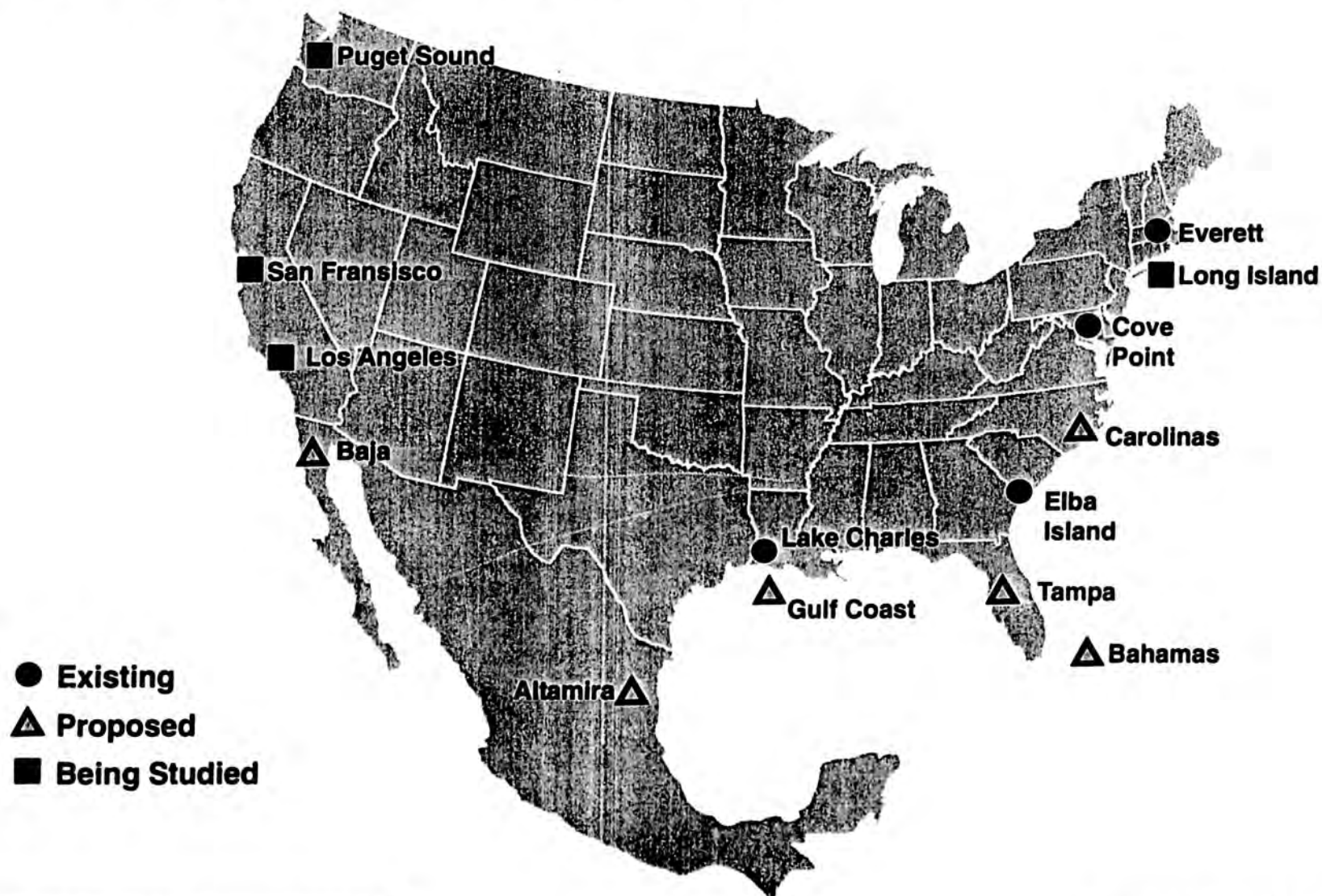
Potential US LNG Destinations for Atlantic LNG



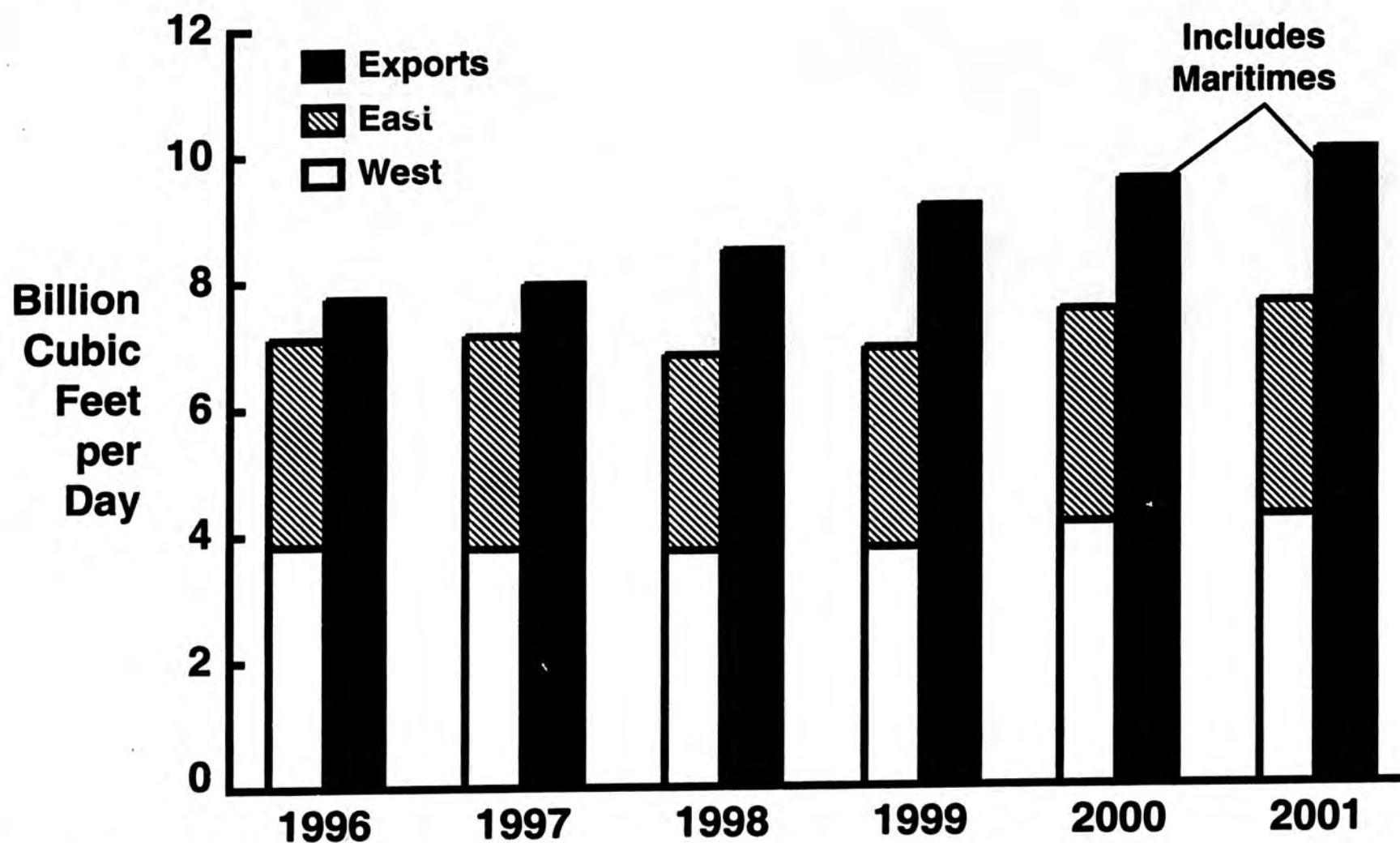
World LNG Facilities



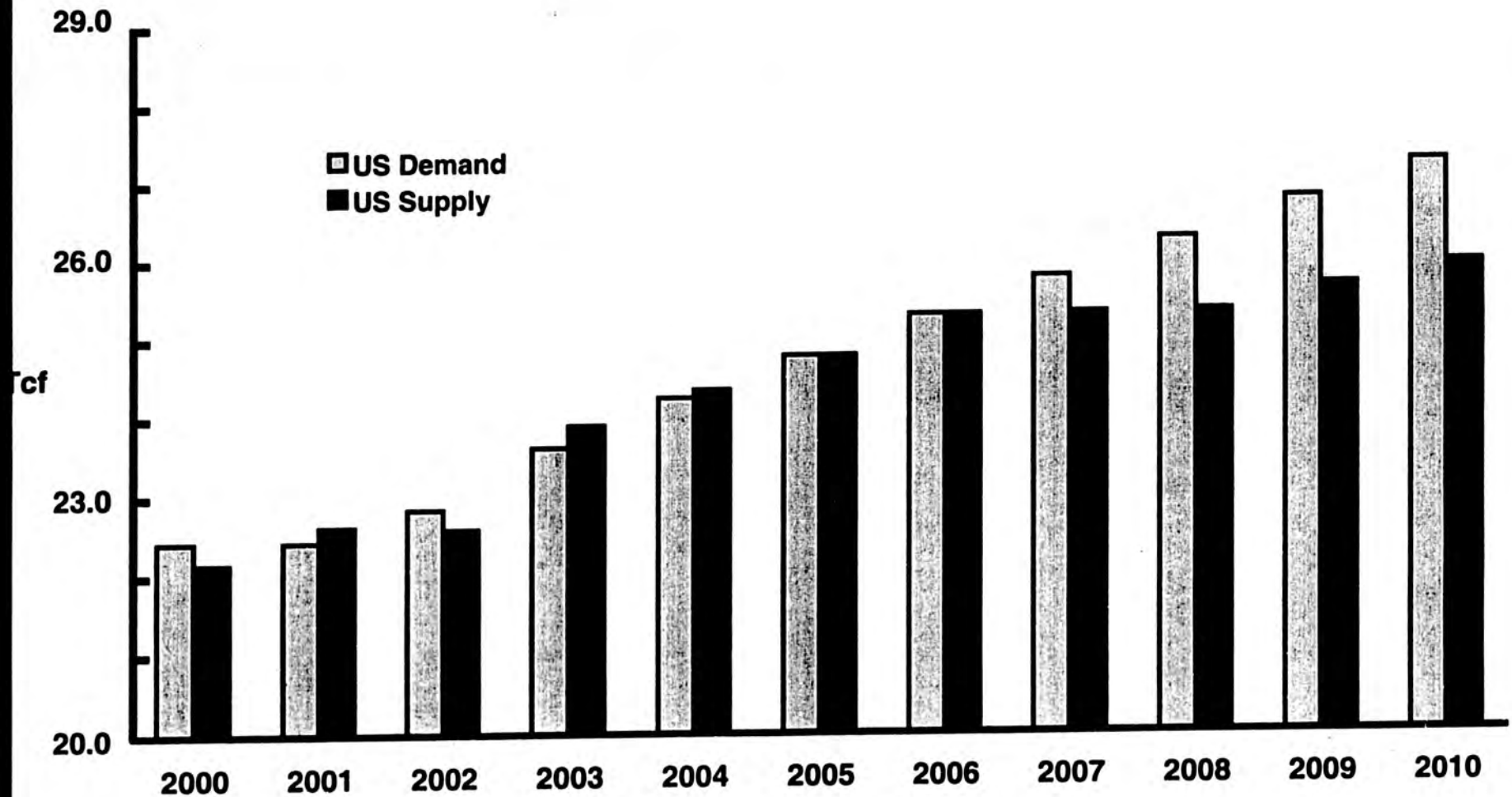
LNG Facilities in North America— Existing and Potential



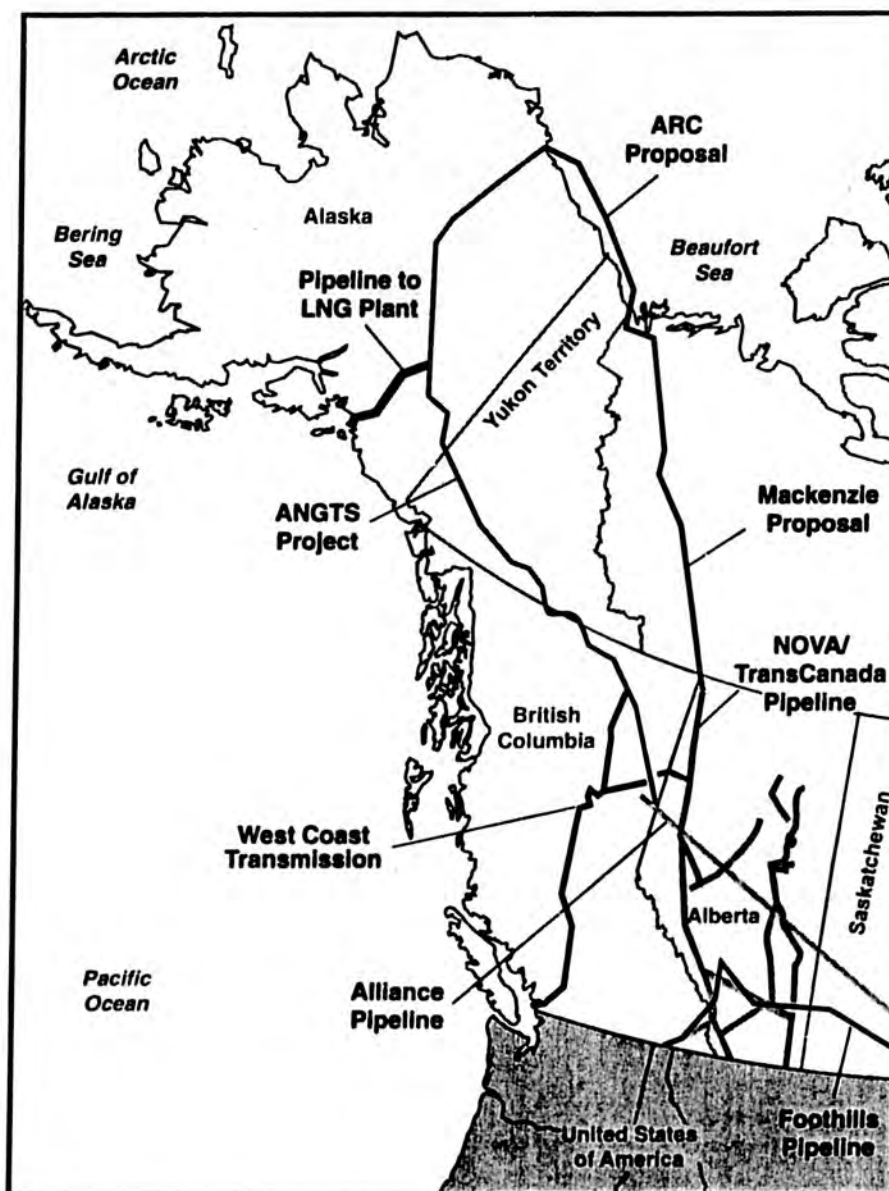
Canadian Domestic Demand and Exports



Lower-48 Supply/Demand balance without Frontier

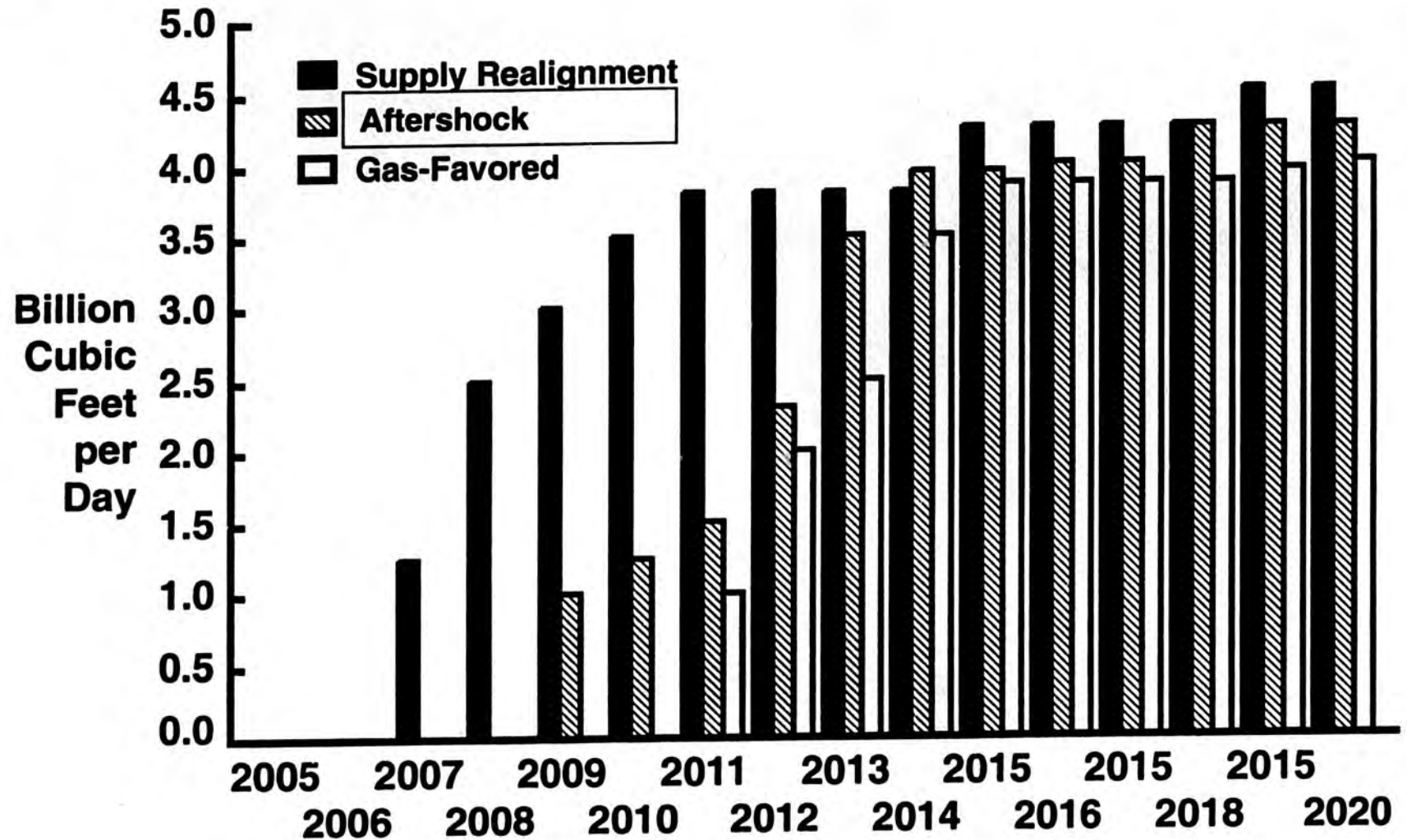


Arctic Gas Pipeline Alternatives



AlaskaStateLegislature_071501_nag

Arctic Gas Supply Build by Scenario



Mackenzie Players

Mackenzie Valley	
Grand River Resources	352,467
AEC	262,093
CNRL	139,631
Foxboro	75,196
Inter. Frontier Res.	71,816
Canadian Abraxas	46,738
Murphy Oil	34,204
Petro-Canada	29,687
BP	9,391
Imperial Oil	3,603
Undiscovered Potential:	5-10 Tcf

Beaufort Sea and Mackenzie Delta	
BP Canada	425,632
Anderson	398,069
PetroCanada	266,909
Burlington/Chevron/BP	219,237
AEC	214,088
Chevron/BP	193,508
Talisman	175,810
Imperial Oil <i>Exxon</i>	100,737
Gulf Canada	92,838
Shell Canada	28,133
Suncor Energy	4,843
Ikhil Resources	3,132
Undiscovered Potential:	45 Tcf

Fort Liard	
Paramount	148,156
Canadian Forest Oil	46,241
BP	27,540
PanCanadian Petroleum	13,025
Suncor Energy	5,622
Chevron Canada	5,110
CNRL	5,090
Undiscovered Potential:	20 Tcf

Cameron Hills	
Paramount	34,489
Phillips	3,771
BP	321
Undiscovered Potential:	1 Tcf

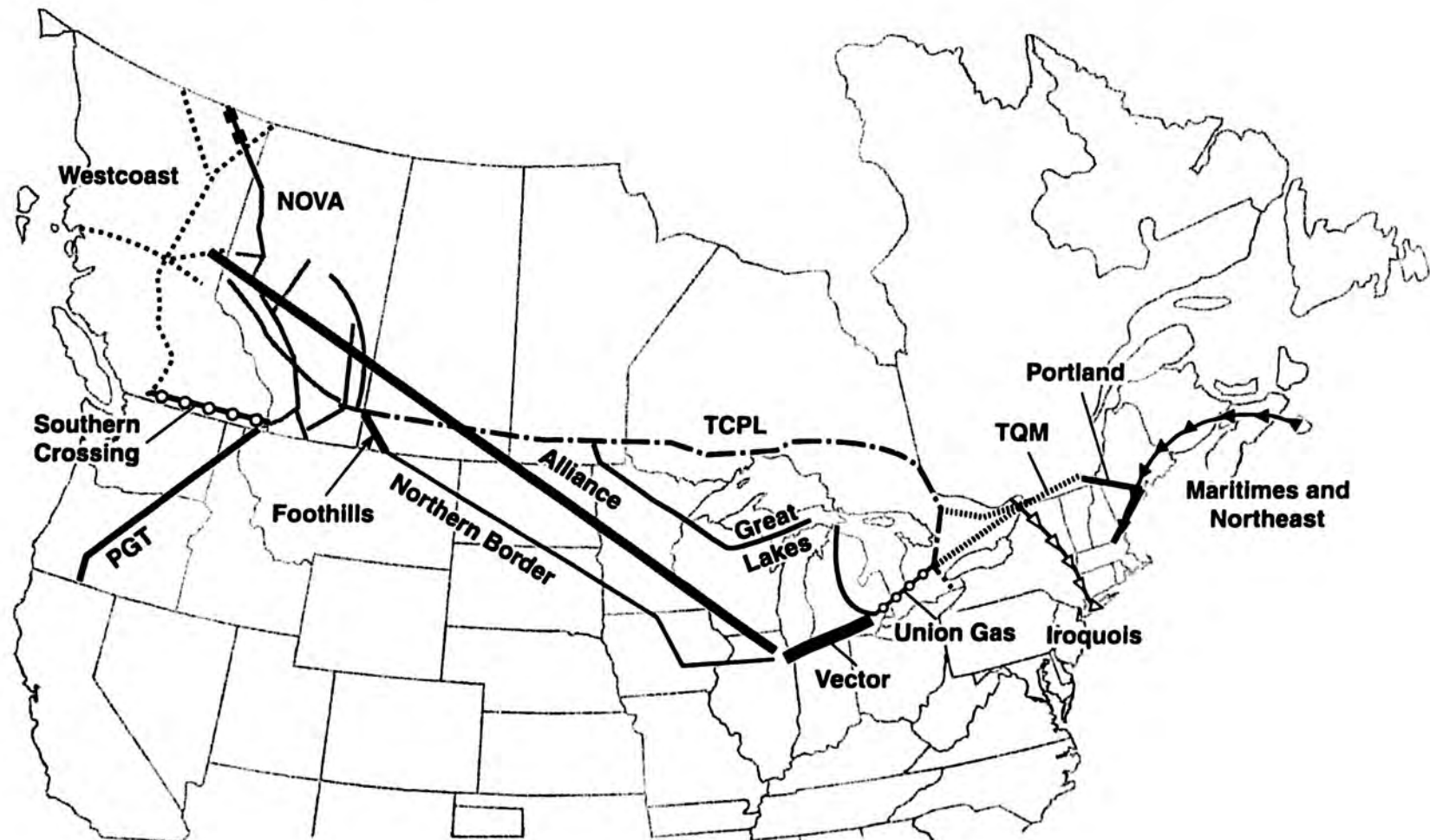


00125-43
1221

Source: Cambridge Energy Research Associates.

AlaskaStateLegislature_071501_nag

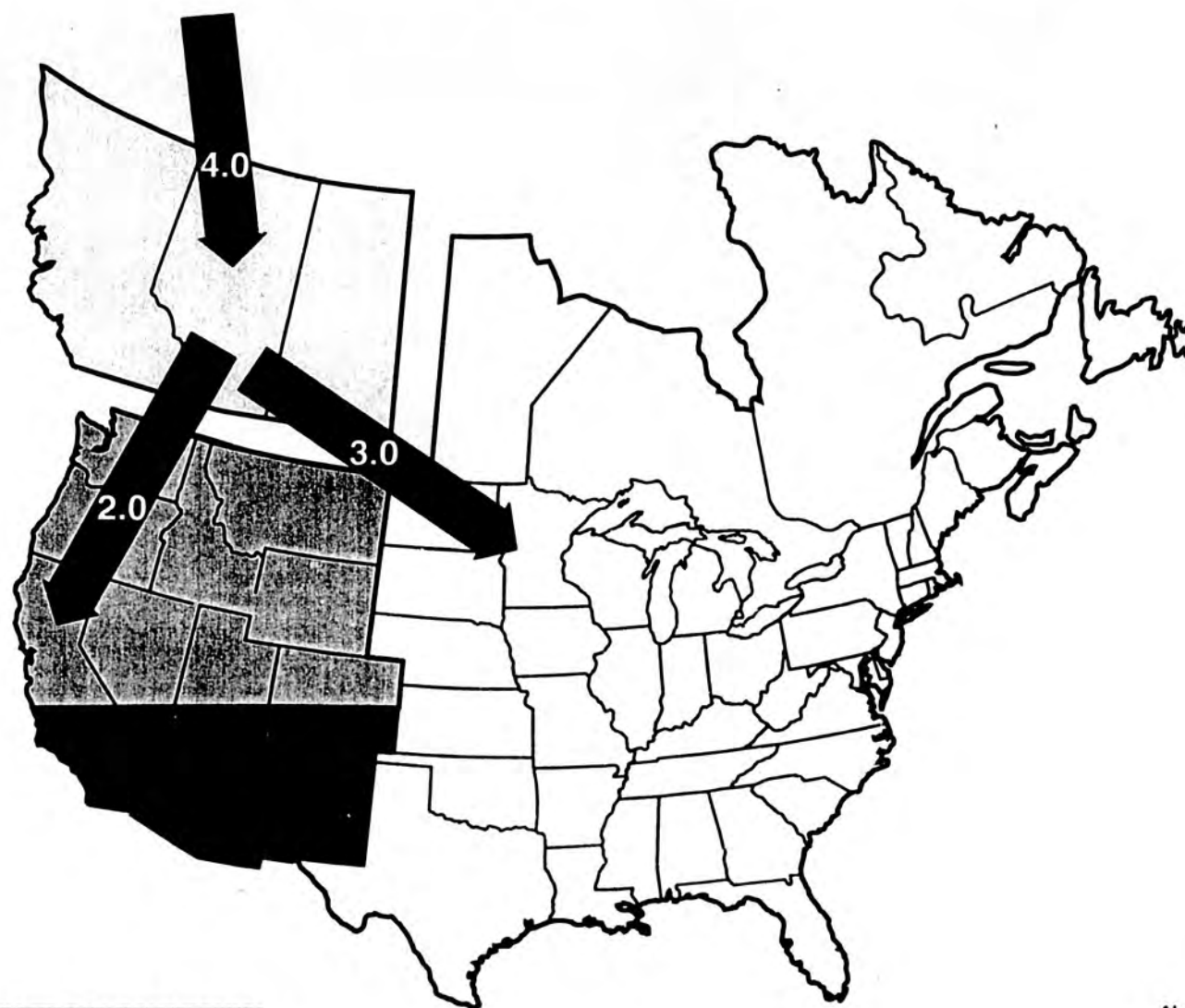
Canadian Natural Gas Pipeline Infrastructure



Source: Cambridge Energy Research Associates.
90306-13
041900

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Western Canada Pipeline Requirements—2010 (Bcf per day)



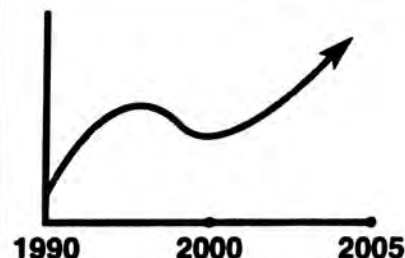
Northern Gas Pipeline Development Risks (1 of 2)



\$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

30 Tcf



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

Northern Gas Pipeline Development

Risks (2 of 2)

Risk Sharing



Construction Delays

- Weather
- Equipment
- Workers



Deeper



CBM

Resource Development

- Ultimate Capability
- New Sources



Risk Sharing

- Pipelines
- Producers
- Markets
- Financial Backing



Liquids

- Disposition
- Increase Economic Viability



Contracts

- Security
- Term Length
- Volume

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

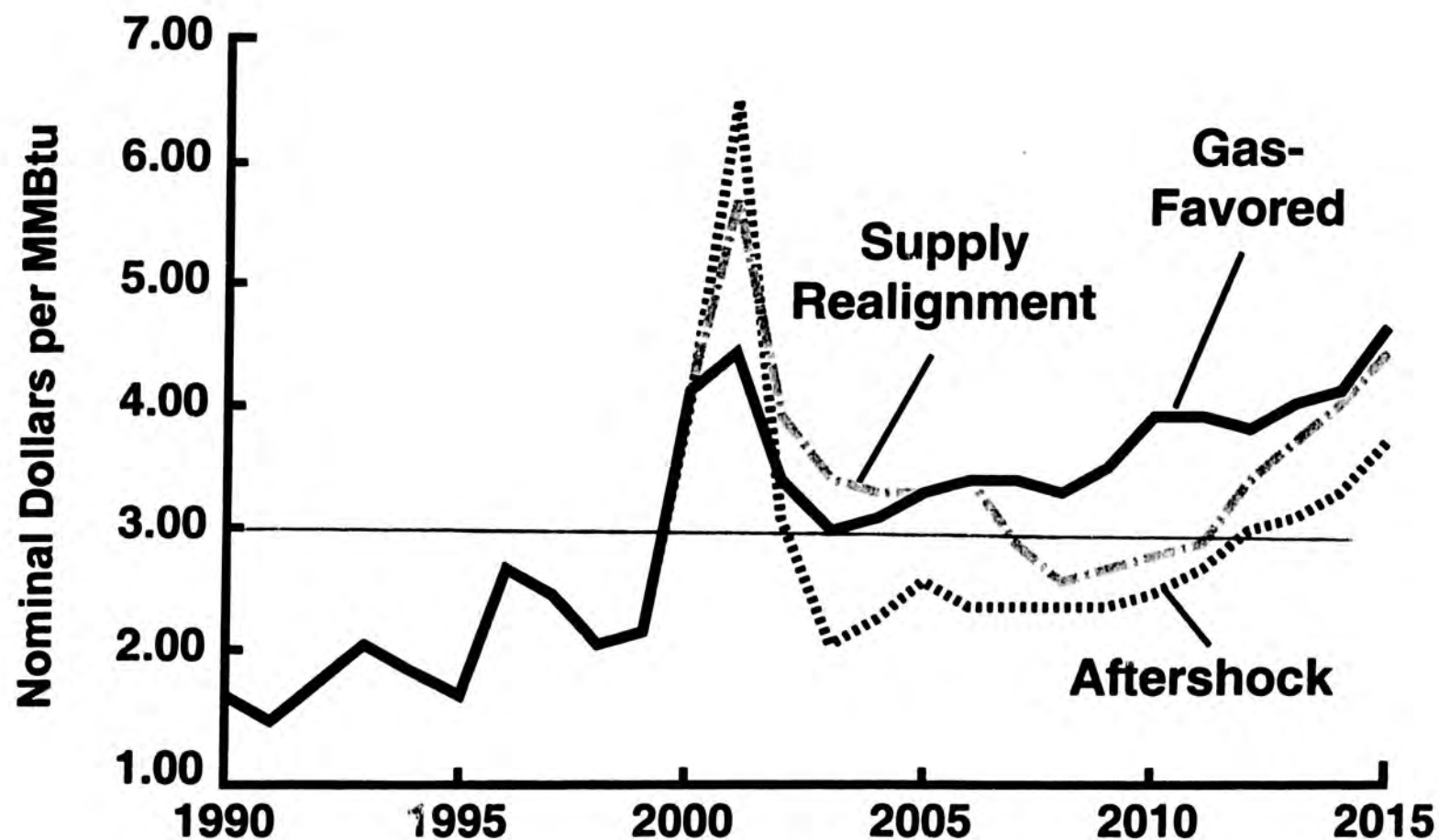
Alliance Impact

- Success for gas
- Disappointment for liquids

Alaska Opportunities?

- Advantages
- Disadvantages

CERA Spot Price—Henry Hub



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

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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 permissibility 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

Mr. John Kerrigan
Acting State Pipeline Coordinator
Joint Pipeline Office
411 West 4th Ave., Suite 2
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:

Messrs. Kerrigan and Brossia
July 2, 2001
Page 2

- 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 pre-filing 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.

Messrs. Kerrigan and Brossia
July 2, 2001
Page 3

Sincerely,

A handwritten signature in black ink, appearing to read "Jeff B. Lowenfels". The signature is fluid and cursive, with the first letters of the first and last names being capitalized and prominent.

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

ATTACHMENT B

TAGS Revision 4 Centerline Alignment

TAGS pipeline centerline Pls 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 Realignment.

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 than 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 (> 500') ⁴	Alignment Code	Approximate Location	Reason for Realignment
From	To	Total	Outside ¹				
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	Approximate Location	Reason for Realignment
From	To	Total	Outside ¹	(> 500') ²	Code		
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. ROW² 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

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T2P 3W8

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

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

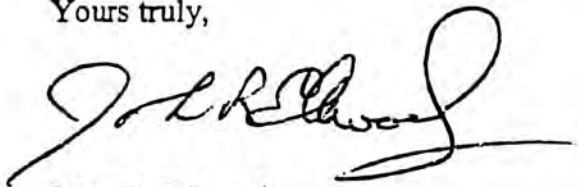
regular route surveillance and continues to pay lease rentals to the State for 152 miles of federal right-of-way transferred to the State.

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 in 1994.

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

TAGS Conditional Lease
ADL 413342
December 10, 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 Requirement 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 submit 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 2A 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.

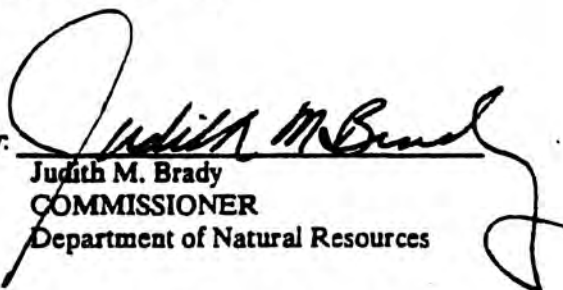
Section 14. Acceptance of LEASE

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

YUKON PACIFIC CORPORATION

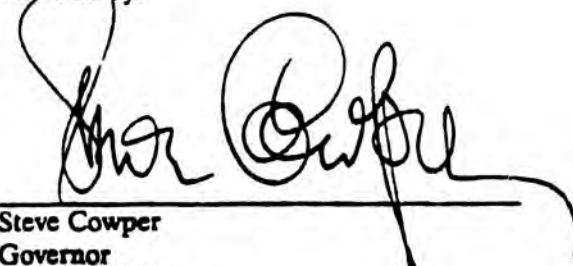
By: 
Judith M. Brady
COMMISSIONER
Department of Natural Resources

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

Date: Dec. 10, 1988

Date: Dec 10, 1988

Attested by:


Steve Cowper
Governor
State of Alaska

TAGS Conditional Lease
ADL 413342
December 10, 1988

State of Alaska)
) ss
)

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

Betty D. Ackerson
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 Edward D. Griffith, 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. Ackerson
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.

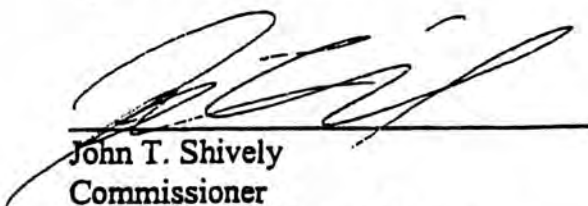
The parties further agree that Section 4 (B) of the CONDITIONAL LEASE shall be amended effective December 12, 1998 to read as follows:

"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)."

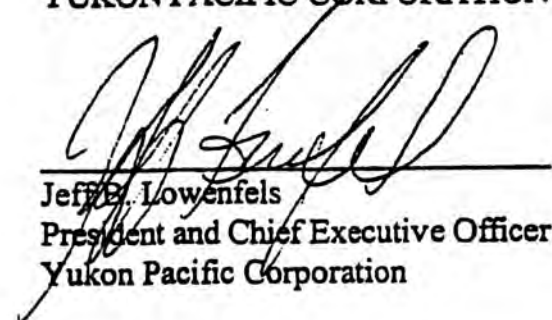
All terms, covenants and conditions to the CONDITIONAL LEASE shall remain in full force and effect.

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

STATE OF ALASKA

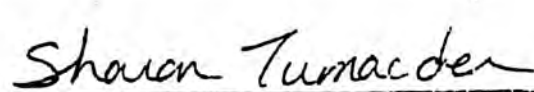

John T. Shively
Commissioner
Department of Natural Resources

YUKON PACIFIC CORPORATION


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

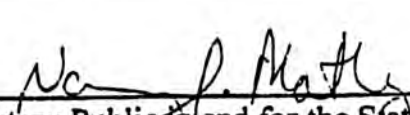
STATE OF ALASKA)
)ss.
THIRD JUDICIAL DISTRICT)

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.


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
governor@gov.state.ak.us



STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

P.O. Box 110001
Juneau, Alaska 99811-0001
(907) 465-3500
Fax (907) 465-3532
www.gov.state.ak.us

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.

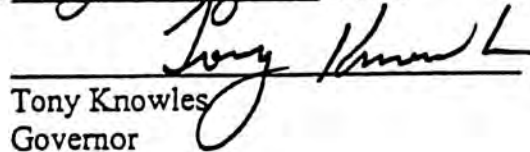
Unless contrary to any dispute resolution process in statute or regulation, in the event of a dispute between Designated Agencies involving a matter subject to the Designated Agencies' statutory or regulatory authority, each affected liaison officer and the SPC will resolve the dispute to the maximum 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.

April 23, 2001

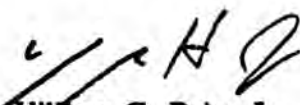
Because the most recent ANNGTC application materials were submitted nearly 20 years ago, and because there does not appear to be a comprehensive index, it is impossible for my staff to determine what should properly be considered confidential. It is also difficult, if not impossible, for my staff to 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.

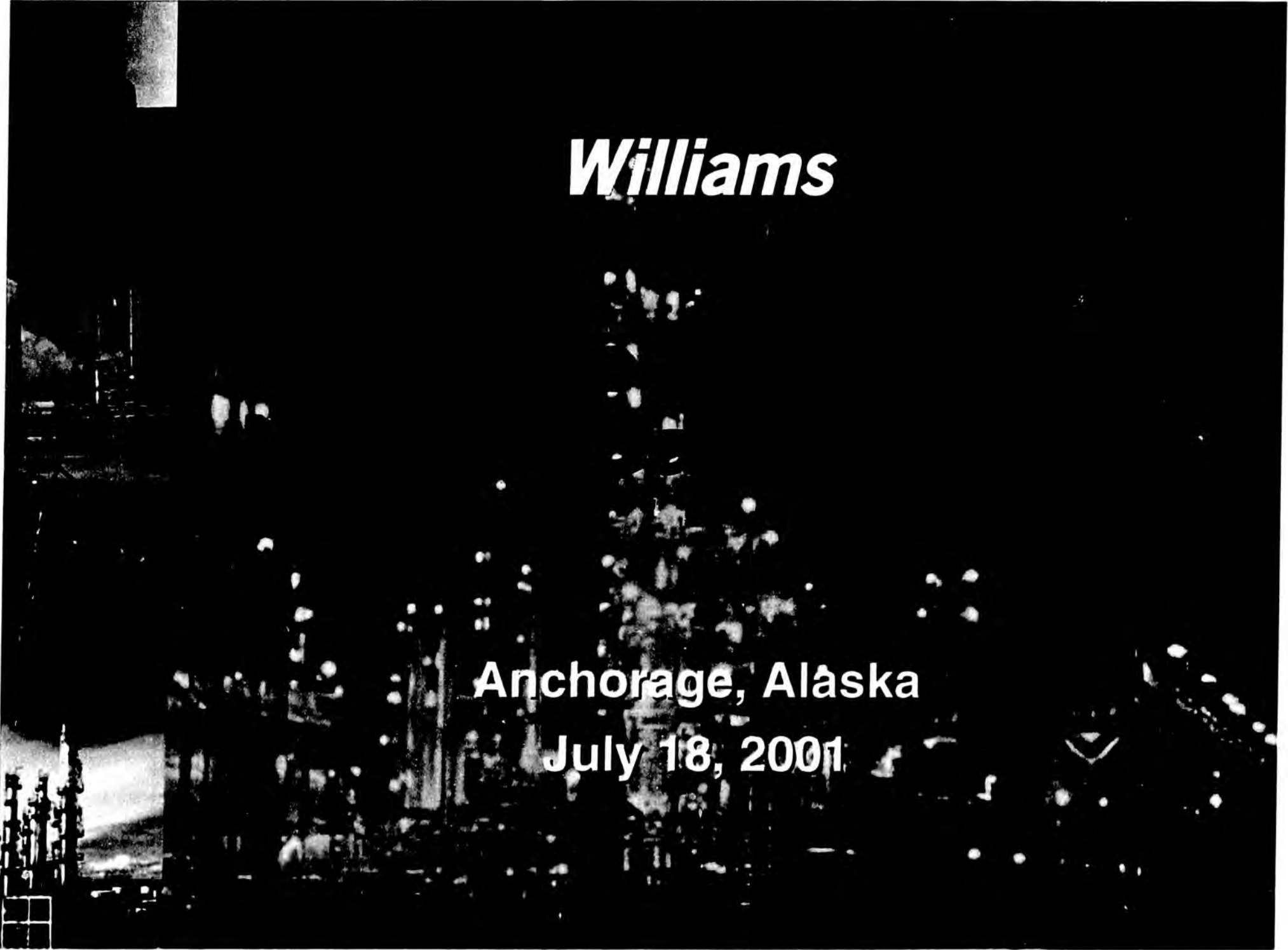
Sincerely



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

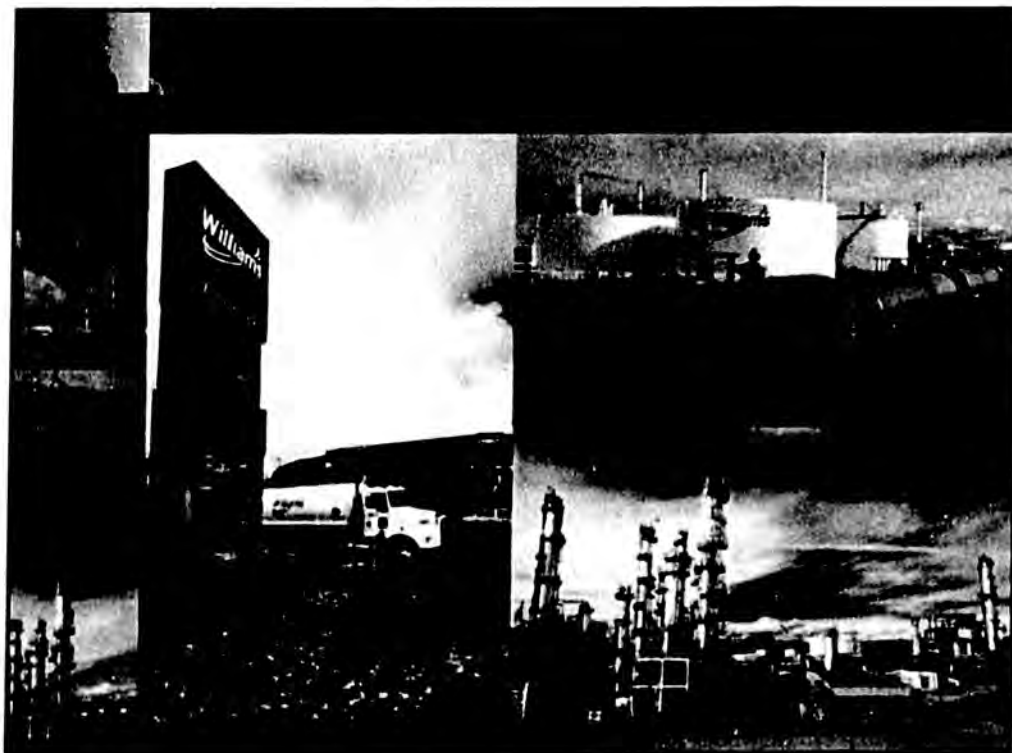
Currently market Alaska's royalty oil

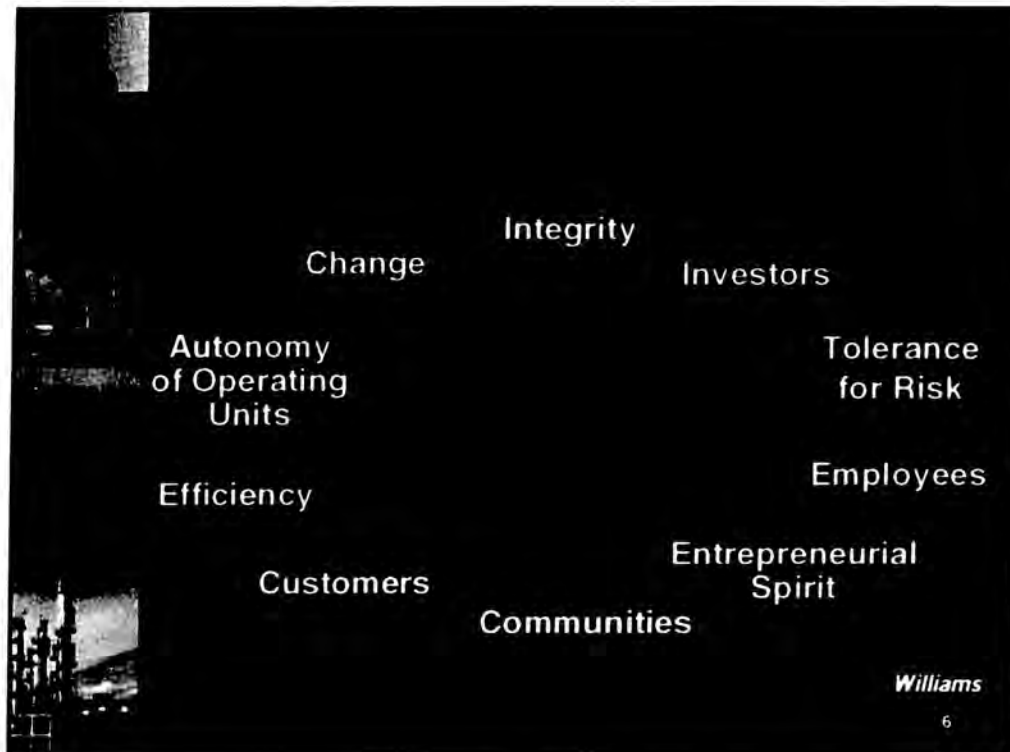
500+ employees with annual payroll
exceeding \$21 million

\$340 million in fixed assets

\$12+ million in annual taxes paid

Williams





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

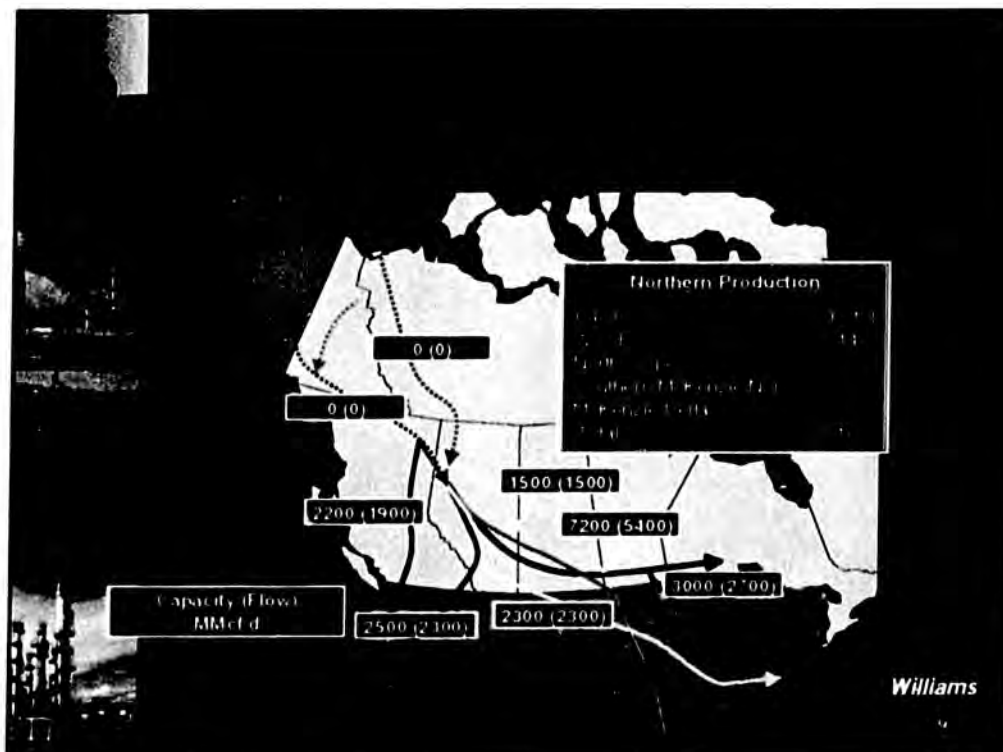
10 - 15 Bcf/d of conventional supply
growth projected during same time period

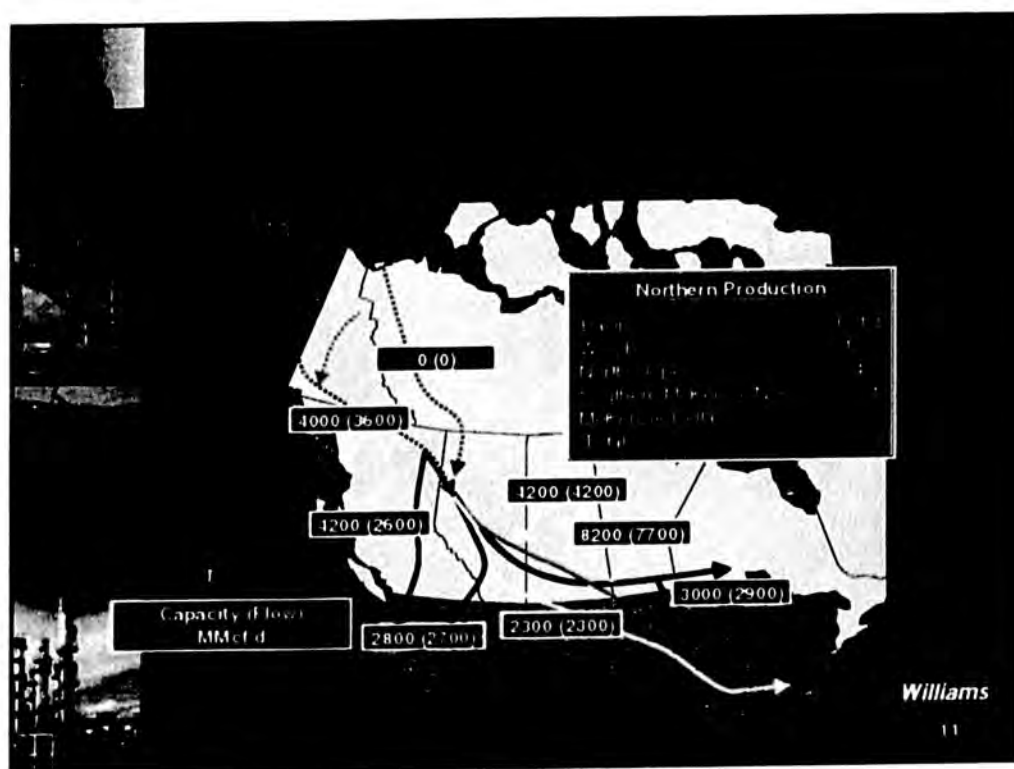
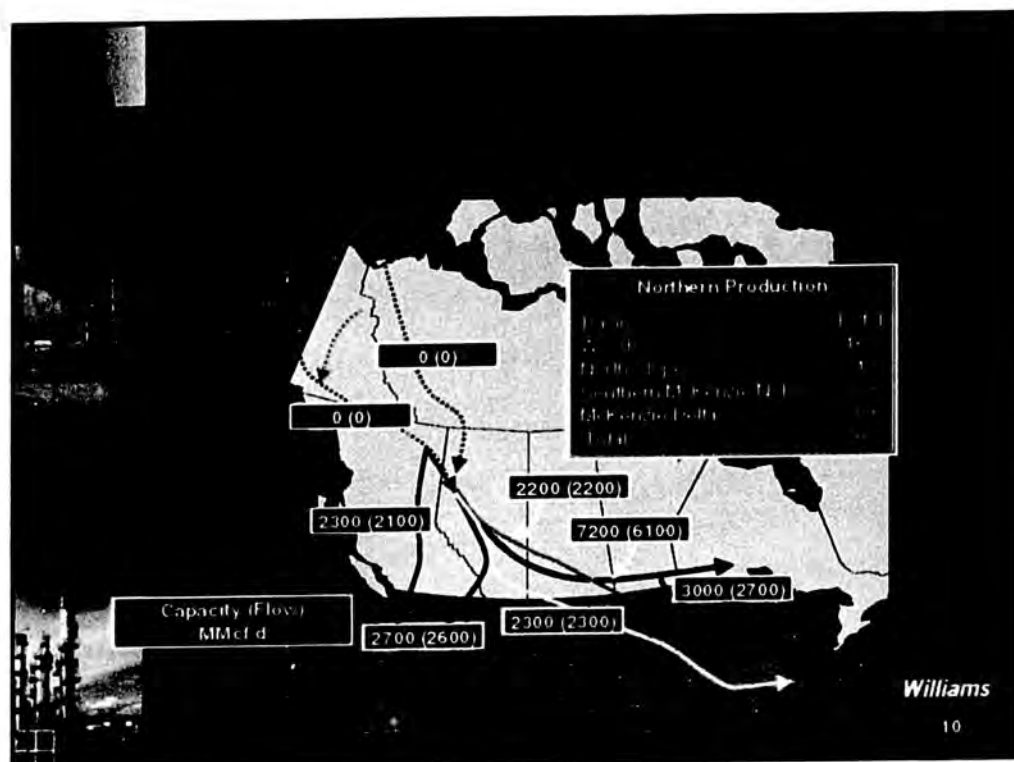
Includes traditional L-48 and WCSB

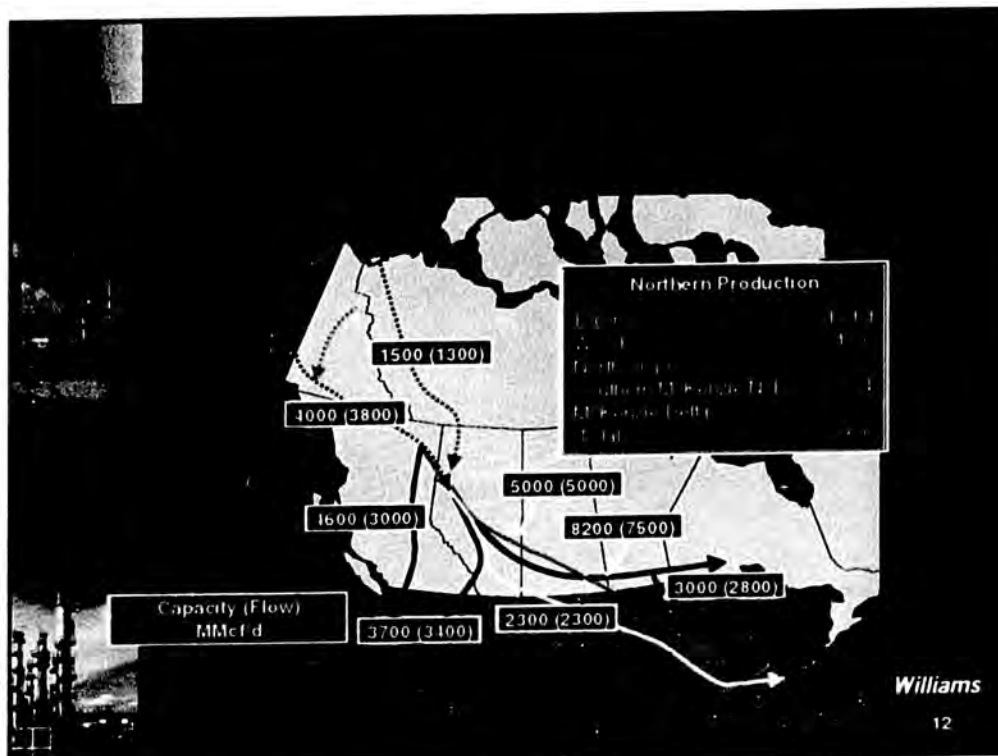
Arctic Gas is needed to fill this hole

Williams

8







Varied deal structure & terms

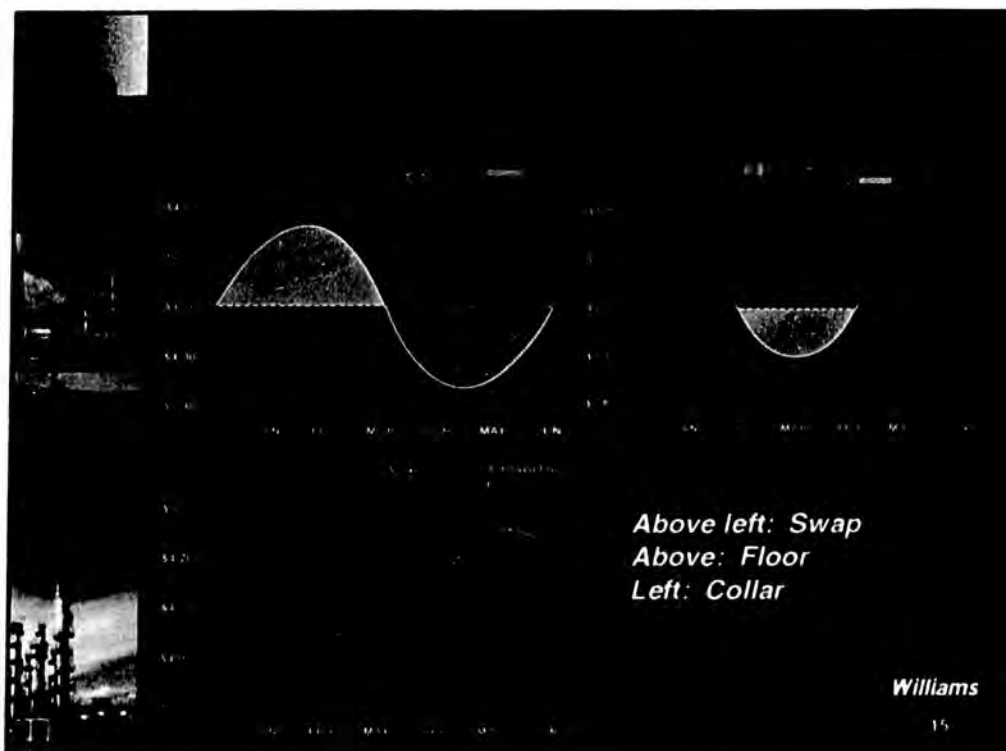
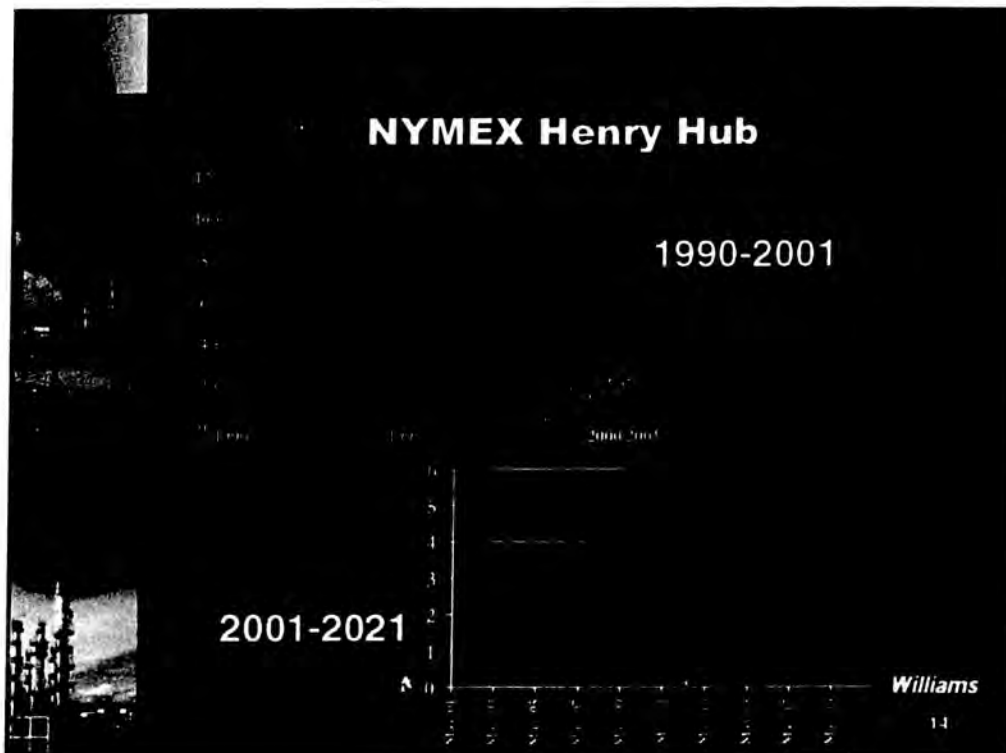
- Ex: 20-year fixed structure

Options available to reduce risk / hedge uncertainty

- Index float
- Swap / fixed
- Floor
- Collar
- Swaption

Williams

13



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
(\$1.13 EBIT/Bbl)

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 40,000
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

26

Ongoing Projects



Williams

27



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

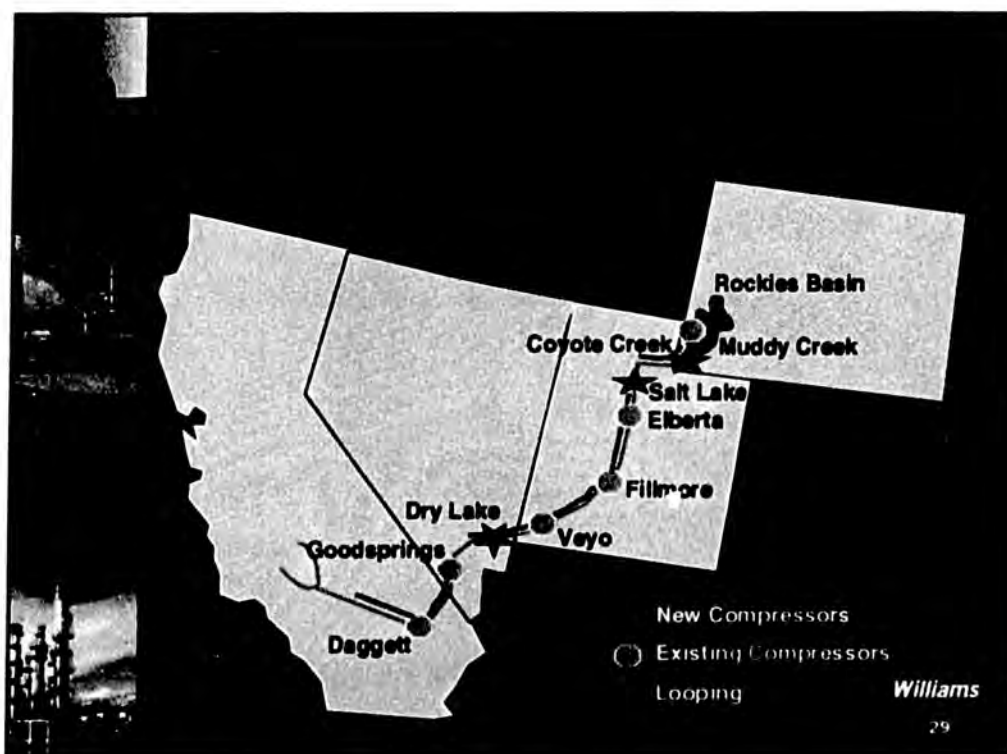
Currently transports over 700 mmcf/d

Will expand by nearly 150% by 2003

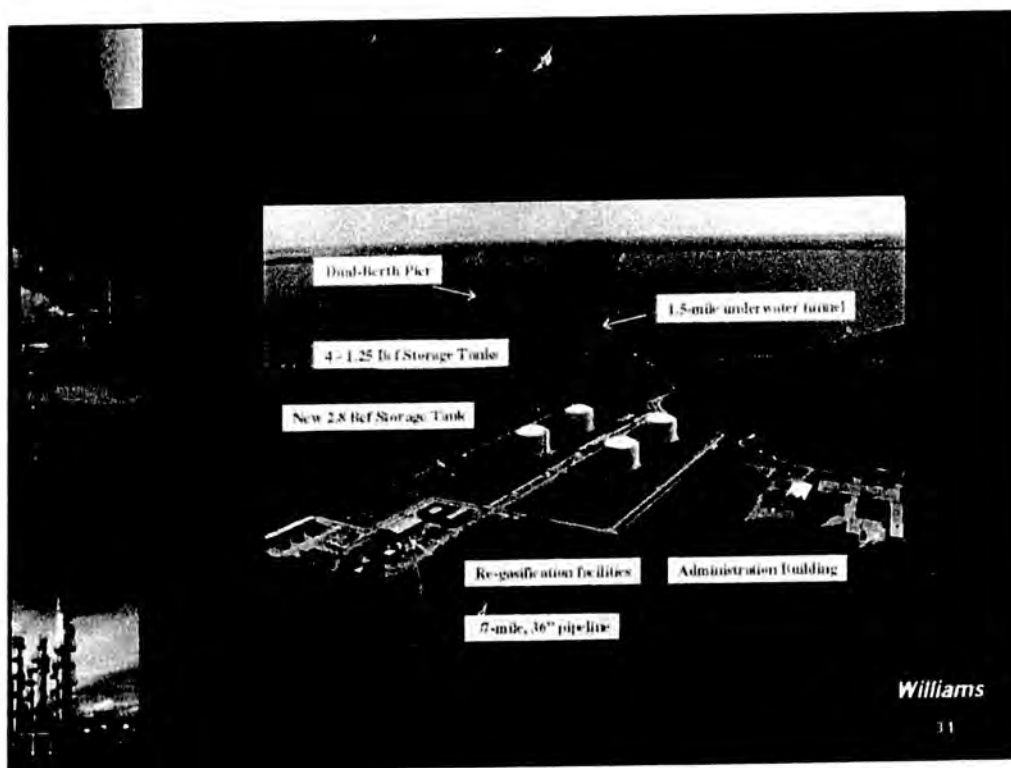
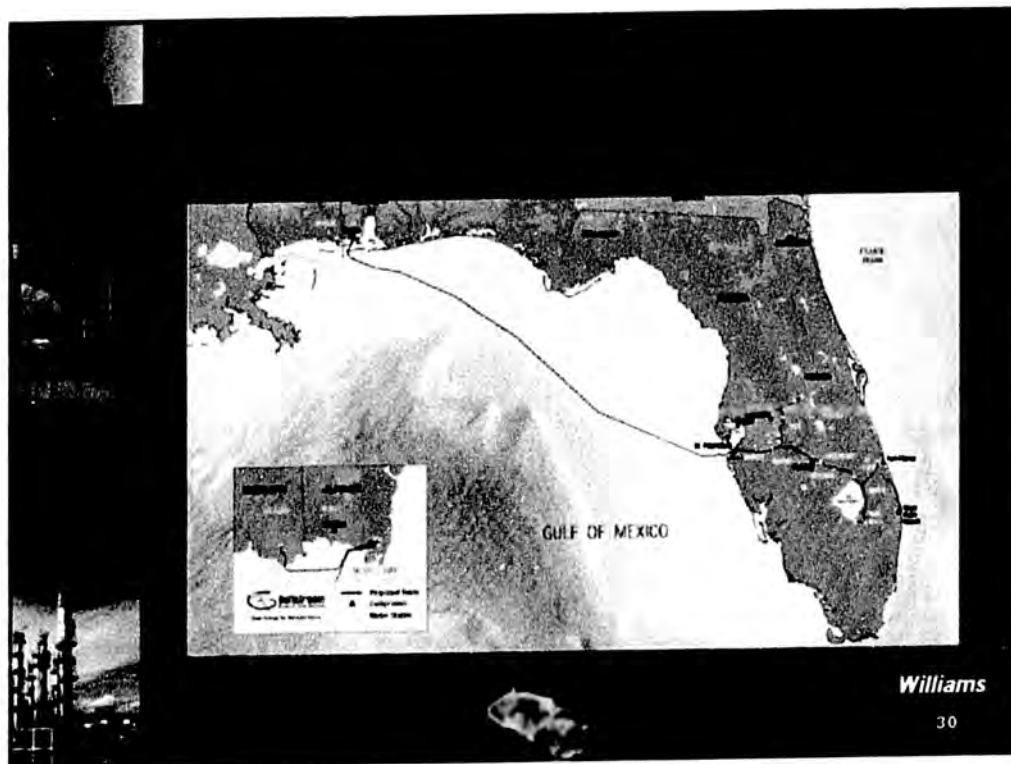
Demonstrates Williams' proven
commitment and experience

Williams

28



29





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

32



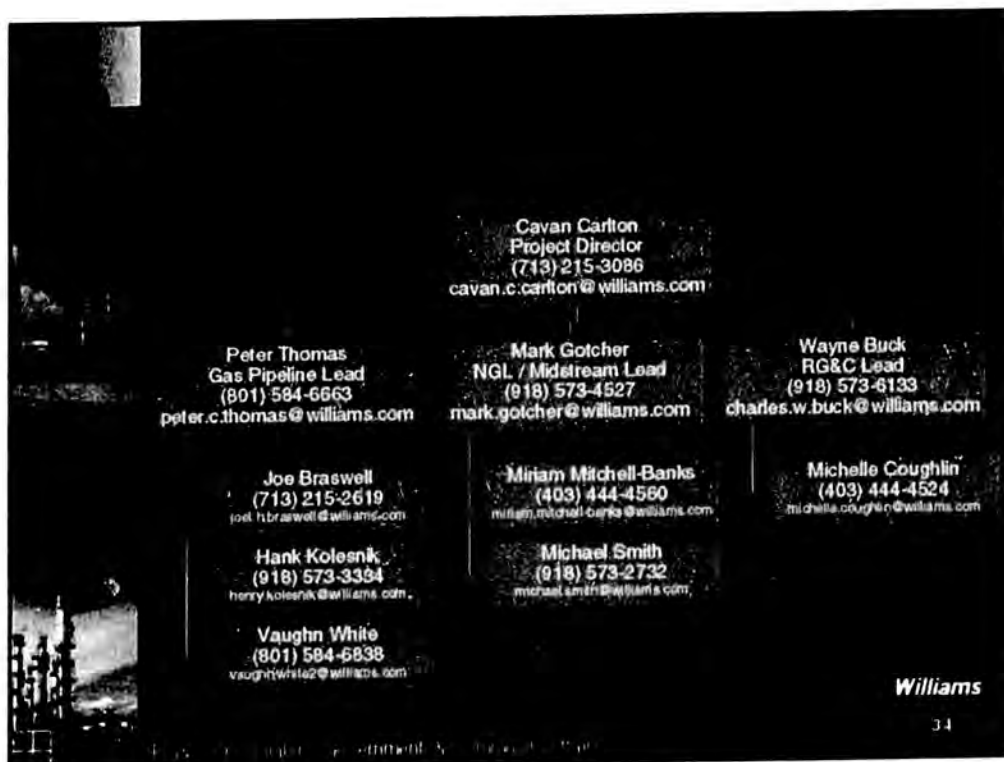
Establishing a dedicated team to pursue
Arctic development

Will work with key stakeholders to
determine optimal solutions for Arctic
gas & liquids

Initiating a feasibility study on
petrochemical development in Alaska

Williams

33



Cavan Carlton
Project Director
(713) 215-3086
cavan.c.carlton@williams.com

Peter Thomas
Gas Pipeline Lead
(801) 584-6663
peter.c.thomas@williams.com

Mark Gotcher
NGL / Midstream Lead
(918) 573-4527
mark.gotcher@williams.com

Wayne Buck
RG&C Lead
(918) 573-6133
charles.w.buck@williams.com

Joe Braswell
(713) 215-2619
joe.braswell@williams.com

Miriam Mitchell-Banks
(403) 444-4560
miriam.mitchell-banks@williams.com

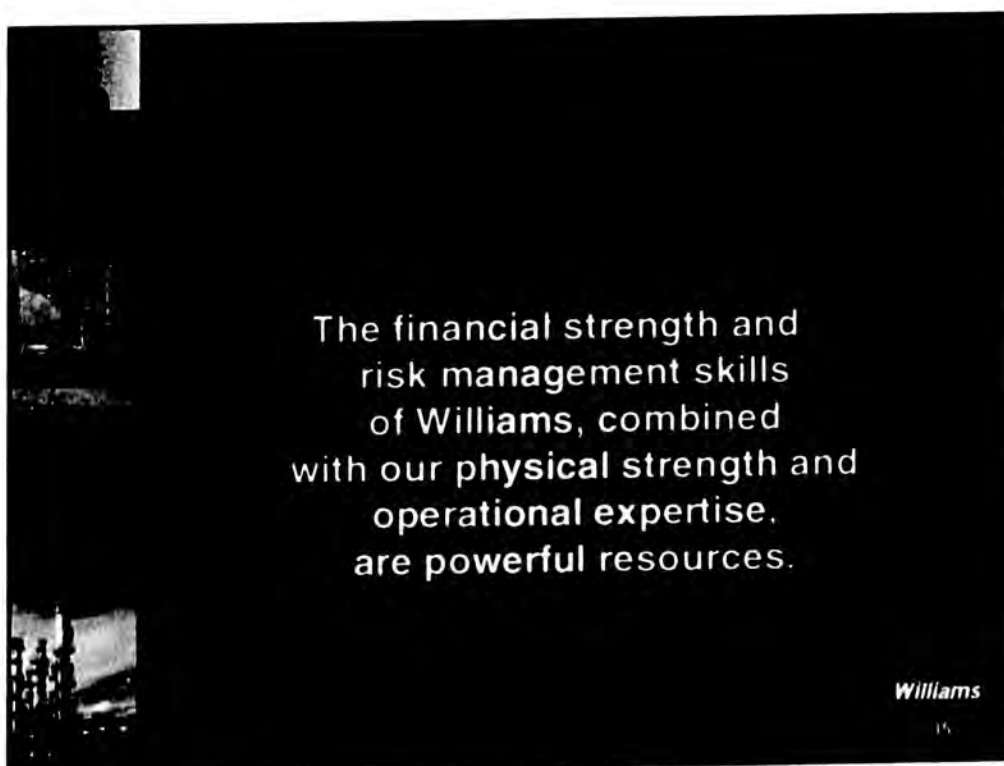
Michelle Coughlin
(403) 444-4524
michelle.coughlin@williams.com

Hank Kolesnik
(918) 573-3334
hank.kolesnik@williams.com

Michael Smith
(918) 573-2732
michael.smith@williams.com

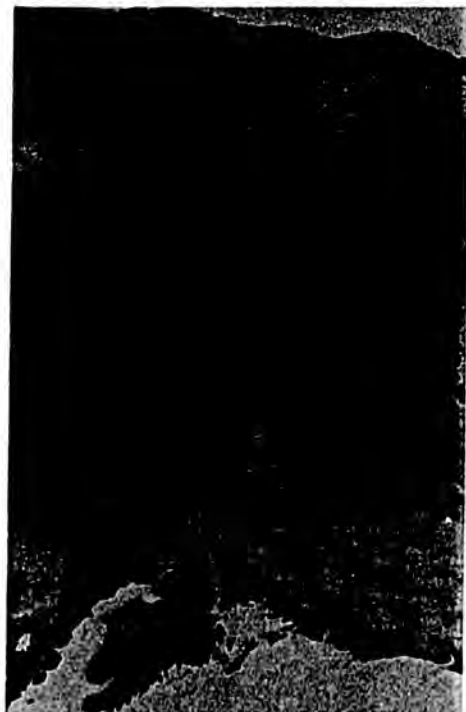
Vaughn White
(801) 584-6838
vaughn.white@williams.com

Williams
34



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

Williams
35



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 infrastruc-

ture 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



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

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

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

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 influences¹, 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 factors²
- 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 LNG from potential proj-

ects 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 allocat-



ed 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.

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

City of Golovin
City of Kotzebue
City of White Mountain
City of Saint Michael
City of Eek
City of Upper Kalskag
City of Goodnews Bay
City of Pelican
City of Shungnak
City of Teller
City of Unalakleet
City of Houston
City of Ouzinkie
City of Emmonak
City of Cordova
City of Lower Stuyahok

City of Wasilla
City of Shaktoolik
City of Coffman Cove
City of Larsen Bay
City of Quinhagak
City of Nulato
City of Huslia
Northwest Arctic Borough
City of Toksook Bay
Kaltag, Alaska
City of Russian Mission
City of Marshall
City of Brevig Mission

Board of Directors

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Al Adams
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Bill Walker
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City of Valdez
Mayor Bert Cottle
Dave Cobb, Secretary
John Kelsey

Special Counsel
Rigdon Boykin
O'Melveny & Myers



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	<u>\$ 3.65 Billion</u>
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.	<u>\$ 1.0 Billion</u>
	\$ 7.8 Billion

Minus pre-completion revenue	<u>-\$ 3.2 Billion</u>
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
Richard Glenn (907) 852-2611	Charlie Cole, Esq. (Vice Chairman) (907) 452-1124	Bert Cottle, Mayor (907) 835-4313
Senator Al Adams (907) 561-5144	Barbara Schuhmann, Esq. (907) 452-1855	John Kelsey (907) 277-2505

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.

A handwritten signature in black ink, consisting of a large, stylized 'M' followed by a series of loops and a horizontal line at the bottom.

CONFIDENTIAL

Alaska Gasline Port Authority

AGPA Financial Model Assumptions and Results

July, 2001

TAYLOR-DEJONGH, INC.



Overview

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

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

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

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.

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.

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

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.

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.

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. |

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

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

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%.

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%

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.

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.

Base Case Assumptions and Results

- 8.745 Bscfd of gas to GCP inlet
- 2.015 Bscfd of CO₂-rich stream returned
- 6.730 Bscfd at 1,158 Btu/scf gas purchased**

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

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

Base Case Assumptions and Results

(cont'd)

Benefits to Producers:

✓ Sale of gas for LNG and Lower 48:

\$ 811 million / yr

\$ 1,216 million / yr

\$ 2,027 million / yr

\$ 0.75 / MMBtu

from gas sale at base payment of \$0.30/MMBtu

from subordinated gas payment of \$0.45/MMBtu

total gas sale revenues

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 CO₂-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 CO₂ over time.

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

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.

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.

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 purchase price

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

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%	6.3%
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 purchase price

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

Summary Sheets of Key Assumptions and Results

Summary of Key Assumptions and Results

Case: Raw Base Case

Last Calculated:

15-Jul-01

Error Checks:

OK

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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	25,789

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 Trolled 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 / Fracturation ⁵	0.12

Gas Value at Canadian Border	1.68
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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
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Total AK State & Muni NPV @ 7.3%	8,855
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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:

- The numbers presented are annual figures for the fully ramped-up project.
- Total benefit per MMBtu of gas into GCP less CO2 stream.
- Netback and feedgas purchase prices are calculated based on total gas flow into the GCP, including CO2 stream and gas for fuel consumption.

- Producer benefits are expressed as pre-tax revenues.
- Based on 2.7% pipeline fuel consumption and a \$450 MM cost of fractionation plant, amortized over 15 yrs at 12% equity return.
- Based on a sales price of \$20/bbl and \$3.50 TAPS tariff.

Summary of Key Assumptions and Results

Case: Raw

LNG and Gas to Canada Price Increase of \$0.10 / MM Btu

Last Calculated:

16-Jul-01
12:23 AM

Error Checks:

Sufficient Cash Flow:

OK
OK

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	1,032
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 Talled 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 / Fractionation ⁵	0.12
Gas Value at Canadian Border	1.78

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 N.V. @ 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:

- The numbers presented are annual figures for the fully ramped-up project.
- Total benefit per MMBtu of gas into GCP less CO2 stream.
- Netback and feedgas purchase prices are calculated based on total gas flow into the GCP, including CO2 stream and gas for fuel consumption.

- Producer benefits are expressed as pre-tax revenues.
- Based on 2.7% pipeline fuel consumption and a \$450 MM cost of fractionation plant, amortized over 15 yrs at 12% equity return.
- Based on a sales price of \$20/bbl and \$3.50 TAPS tariff.

Summary of Key Assumptions and Results

Case: Raw

Interest Rate Decrease of 50 bp

Last Calculated:

15-Jul-01
11:07 PM

Error Checks:

Sufficient Cash Flow:

OK
OK

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
CO ₂ 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 Talled Gas (bbl/d)	
LPG	-
NGL	-
Prices of Liquids (\$ / bbl)	
LPG	12.50
NGL ⁶	16.50

Cash Flow Results (\$ MM)	
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:

- The numbers presented are annual figures for the fully ramped-up project.
- Total benefit per MMBtu of gas into GCP less CO₂ stream.
- Netback and feedgas purchase prices are calculated based on total gas flow into the GCP, including CO₂ stream and gas for fuel consumption.

- Producer benefits are expressed as pre-tax revenues.
- Based on 2.7% pipeline fuel consumption and a \$450 MM cost of fractionation plant, amortized over 15 yrs at 12% equity return.
- Based on a sales price of \$20/bbl and \$3.50 TAPS tariff.

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:

Sufficient Cash Flow:

OK

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 Trolled 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 Price³	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:

- The numbers presented are annual figures for the fully ramped-up project.
- Total benefit per MMBtu of gas into GCP less CO2 stream.
- Netback and feedgas purchase 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.

Summary of Key Assumptions and Results

Case: Raw

\$1 bln EPC Cost Reduction

Last Calculated:

16-Jul-01
9:44 AM

Error Checks:

Sufficient Cash Flow:

OK
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 Trolled 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	1,258
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:

- The numbers presented are annual figures for the fully ramped-up project.
- Total benefit per MMBtu of gas into GCP less CO2 stream.
- Netback and feedgas purchase prices are calculated based on total gas flow into the GCP, including CO2 stream and gas for fuel consumption.

- Producer benefits are expressed as pre-tax revenues.
- Based on 2.7% pipeline fuel consumption and a \$450 MM cost of fractionation plant, amortized over 15 yrs at 12% equity return.
- Based on a sales price of \$20/bbl and \$3.50 TAPS tariff.

Summary of Key Assumptions and Results

Case: Raw

Private Project, 100:0 Debt/Equity

Last Calculated:

17-Jul-01

12:42 PM

Error Checks:

Sufficient Cash Flow:

OK

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 Trolled 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
Operating Expenses	
Gas Purchase	811
Fixed O&M Expense	222
NGL Royalty and Severance	81
Total Operating Expenses	1,114
Income Taxes	
Income Taxes	516
Senior Debt Service	2,280
Average DSCR	
Average DSCR	1.86 x
Minimum DSCR	
Minimum DSCR	1.55 x
In Year	
In Year	2020
Subordinated Debt Service	
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	
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 Price³	0.69

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

Benefits to State (\$ MM)²	
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	
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	
Total to AK State & Communities	1,163
Total AK State & Muni NPV @ 7.3%	
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	
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:

- The numbers presented are annual figures for the fully ramped up project.
- Total benefit per MMBtu of gas into GCP less CO2 stream.
- Netback and feedgas purchase 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.

Summary of Key Assumptions and Results

Case: Raw

Private Project, 70:30 Debt/Equity

Last Calculated:

15-Jul-01

11:11 PM

Error Checks:

Sufficient Cash Flow:

OK

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 Topped 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 Price³	0.75

Gas to Canada Price (\$ / MM Btu)	
Assumed Chicago Price	3.00
Tariff Alaska-Alberta-Chicago	1.20
Charge for Fuel / Fractionation 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

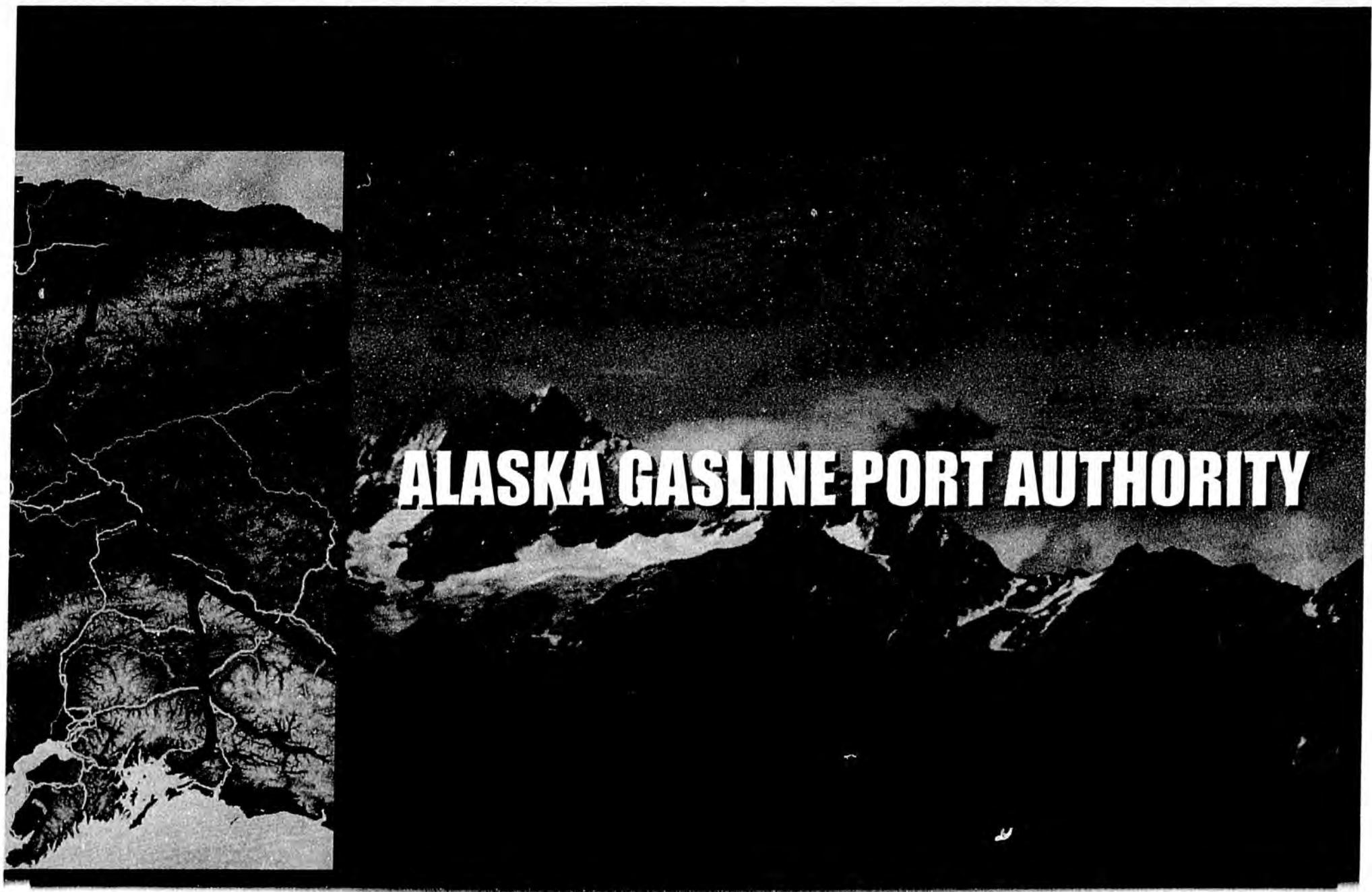
Present Value of Producer Revenues	
Producer NPV @ 12.0%	9,620
Valuation Date	Sep-01

Project Returns	
Equity IRR (leveraged)	3.1%
Equity NPV(leveraged) @ 12.0%	(3,346)
Valuation Date	Sep-01

Notes:

- The numbers presented are annual figures for the fully ramped-up project.
- Total benefit per MMBtu of gas into GCP less CO2 stream.
- Netback and feedgas purchase prices are calculated based on total gas flow into the GCP, including CO2 stream and gas for fuel consumption.

- Producer benefits are expressed as pre-tax revenues.
- Based on 2.7% pipeline fuel consumption and a \$450 MM cost of fractionation plant, amortized over 15 yrs at 12% equity return.
- Based on a sales price of \$20/bbl and \$3.50 TAPS tariff.



ALASKA GASLINE PORT AUTHORITY

AGPA

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



Alaska Gasline Port Authority

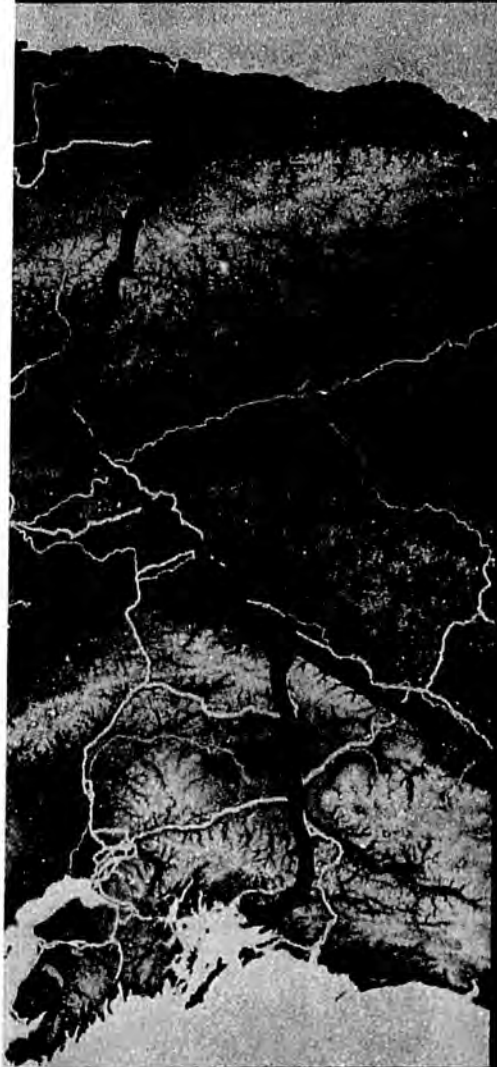
The Alaska Gasline Port Authority consists of three municipalities

- North Slope Borough
- Fairbanks North Star Borough
- City of Valdez



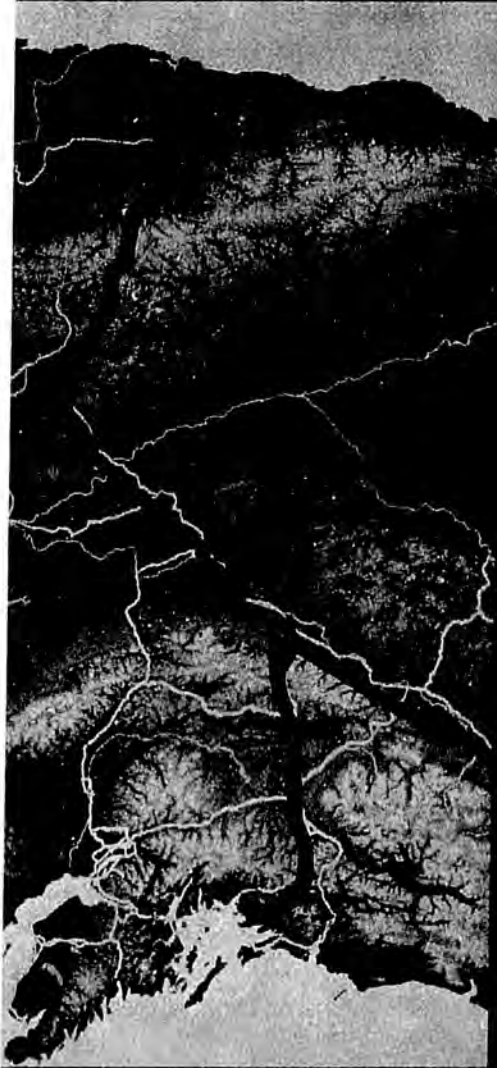
Alaska Gasline Port Authority's Mission

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.



AGPA

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

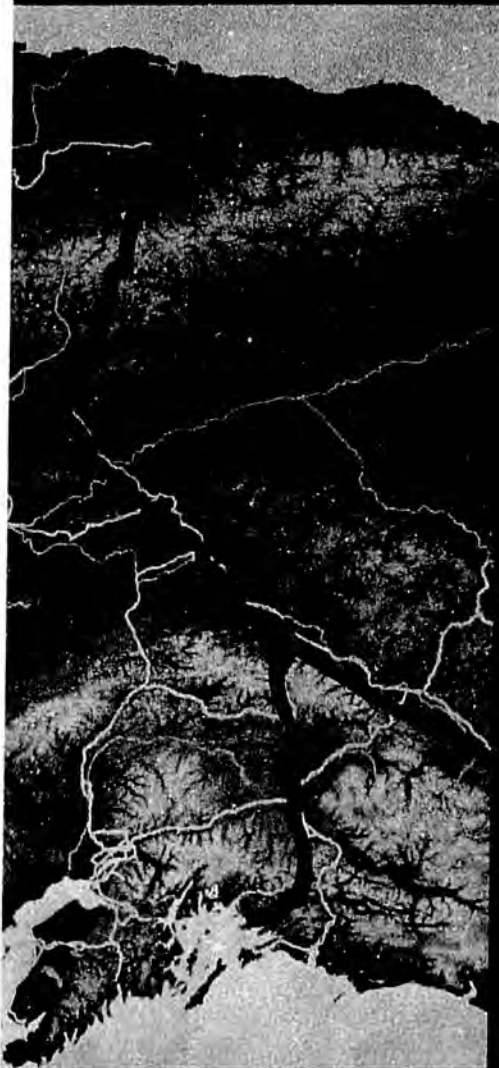
**Bechtel Corporation – technical and
development support**

**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

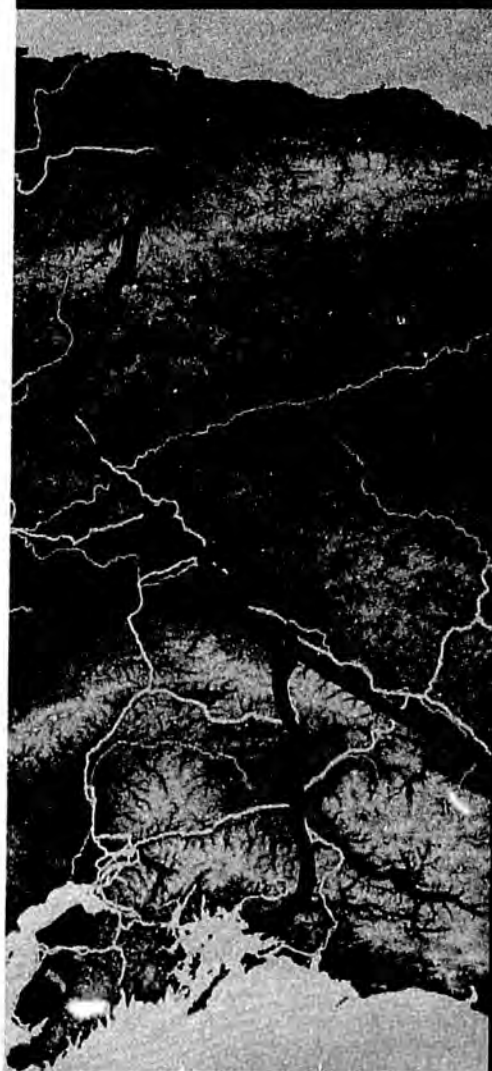
150-mile, 44-inch diameter pipeline to Canadian border for interconnect to lower 48

**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."

AGPA

Benefits of Port Authority Ownership



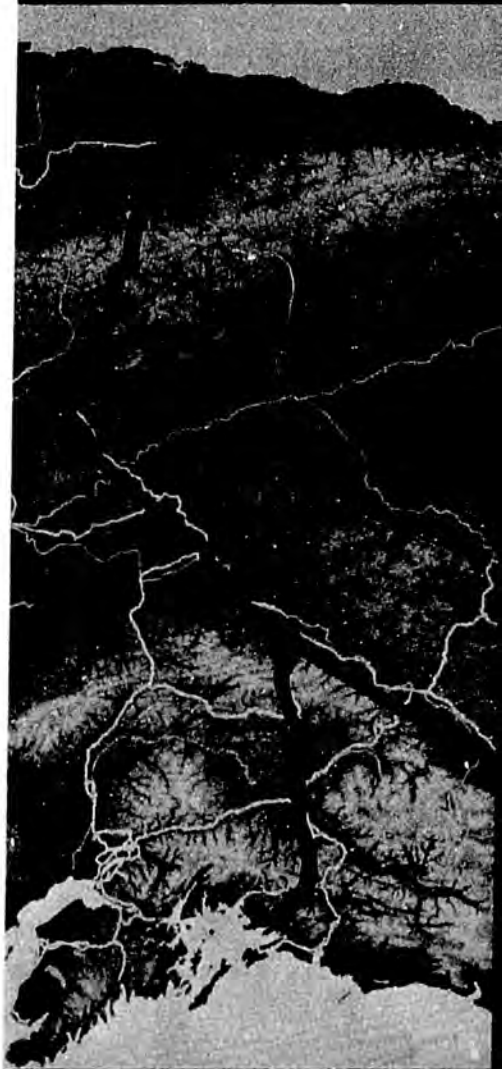
Guarantees maximum in state usage of North Slope gas

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

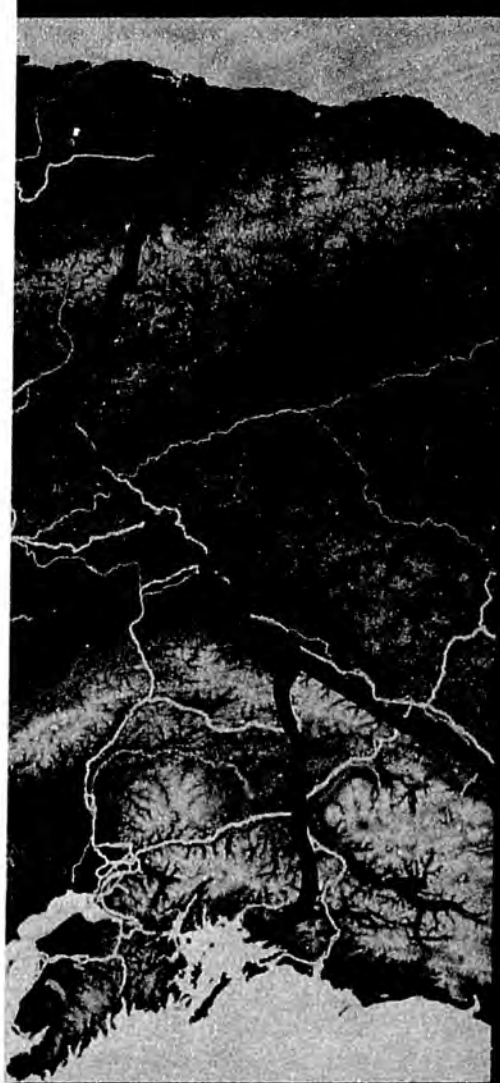
More certainty of gas available for in-state usage and more control over price

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

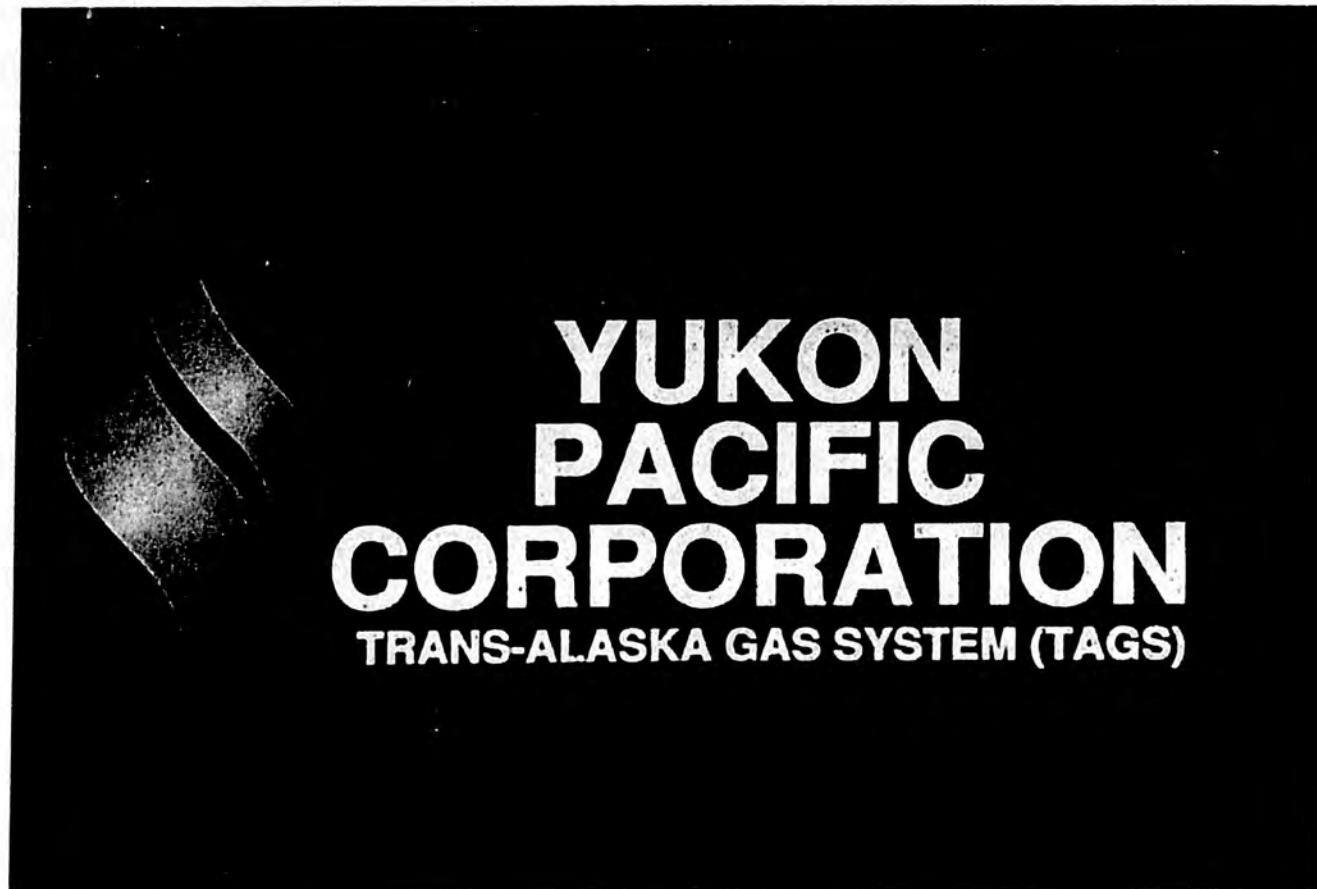


ALASKA GASLINE PORT AUTHORITY

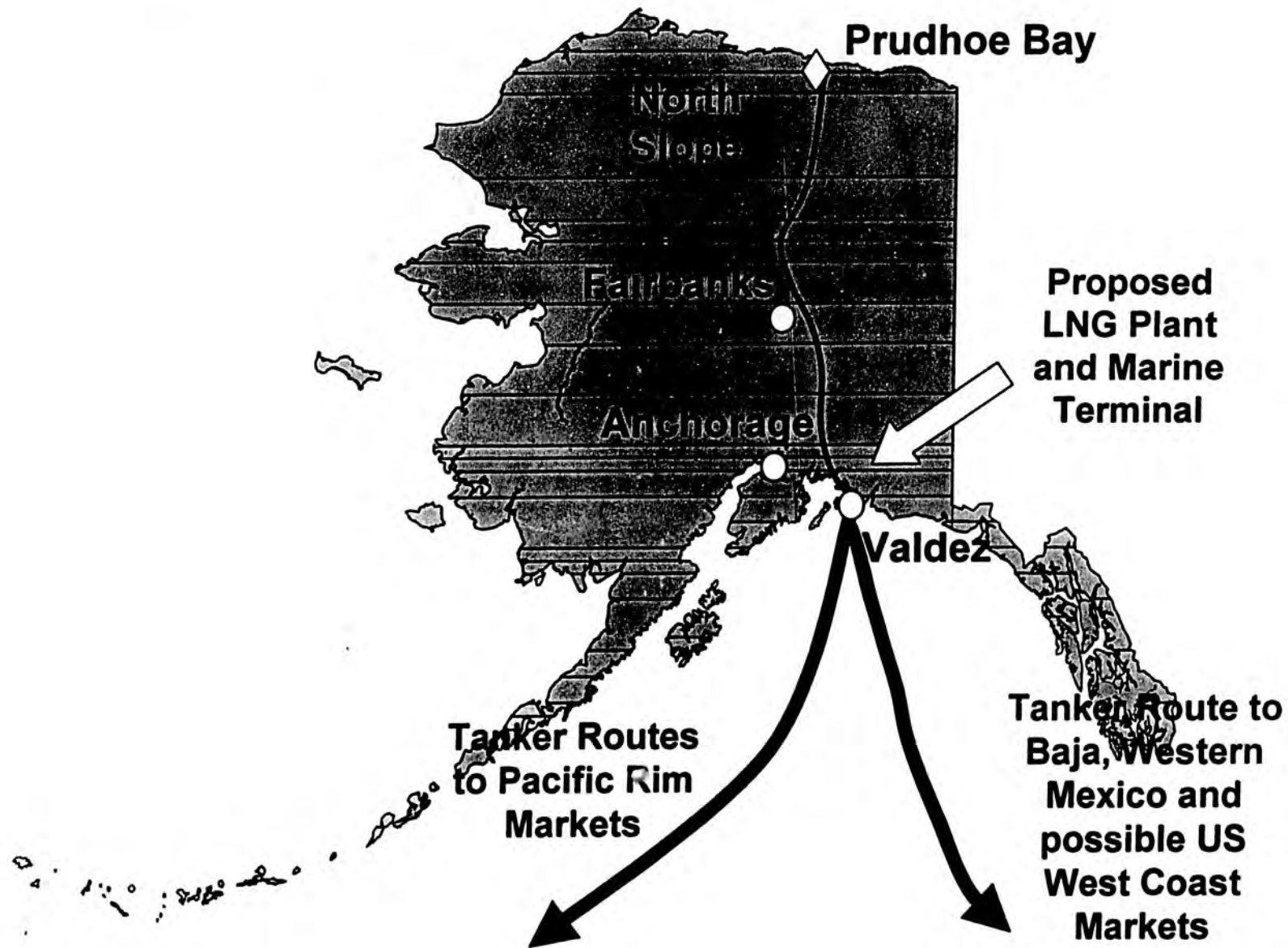
AGPA

**YUKON
PACIFIC
CORPORATION**
TRANS-ALASKA GAS SYSTEM (TAGS)

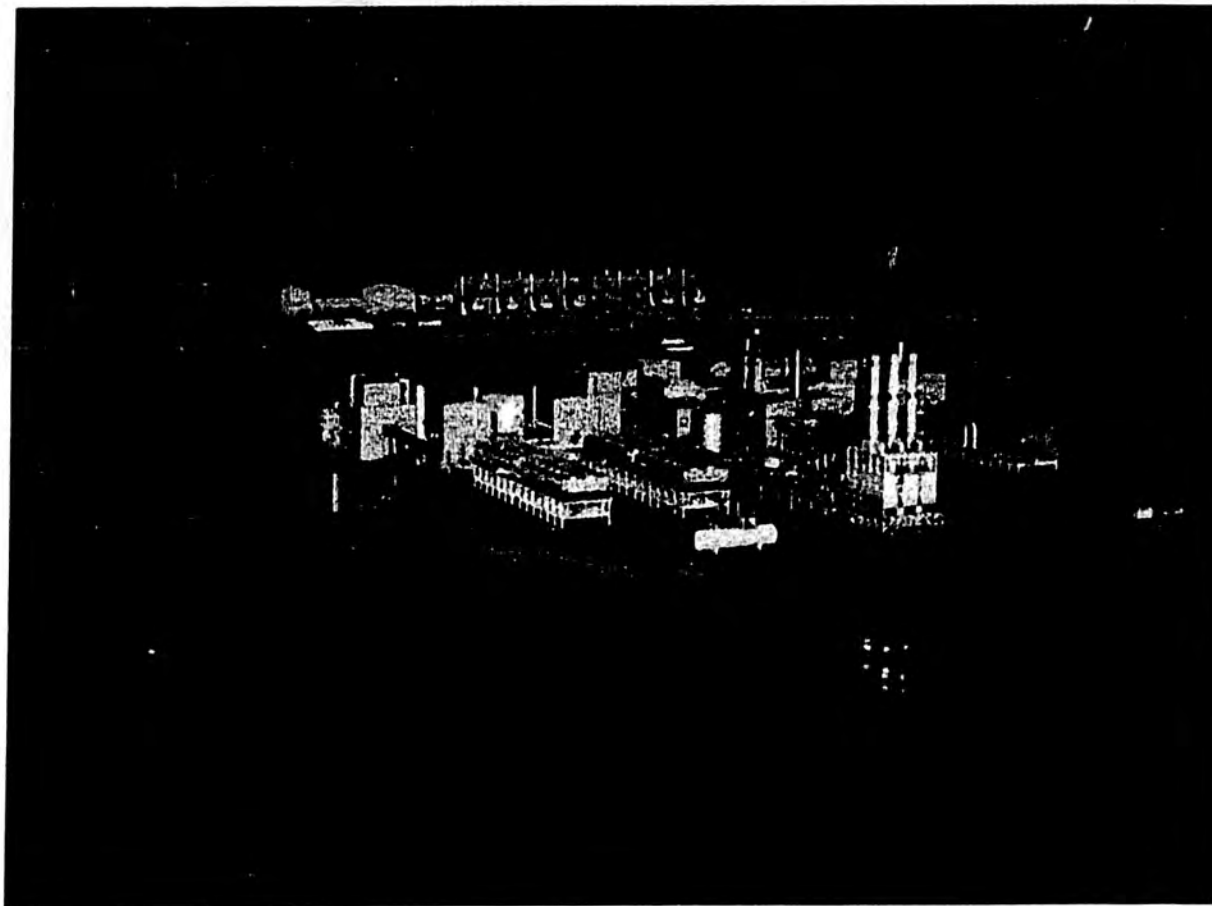
TAGS Components



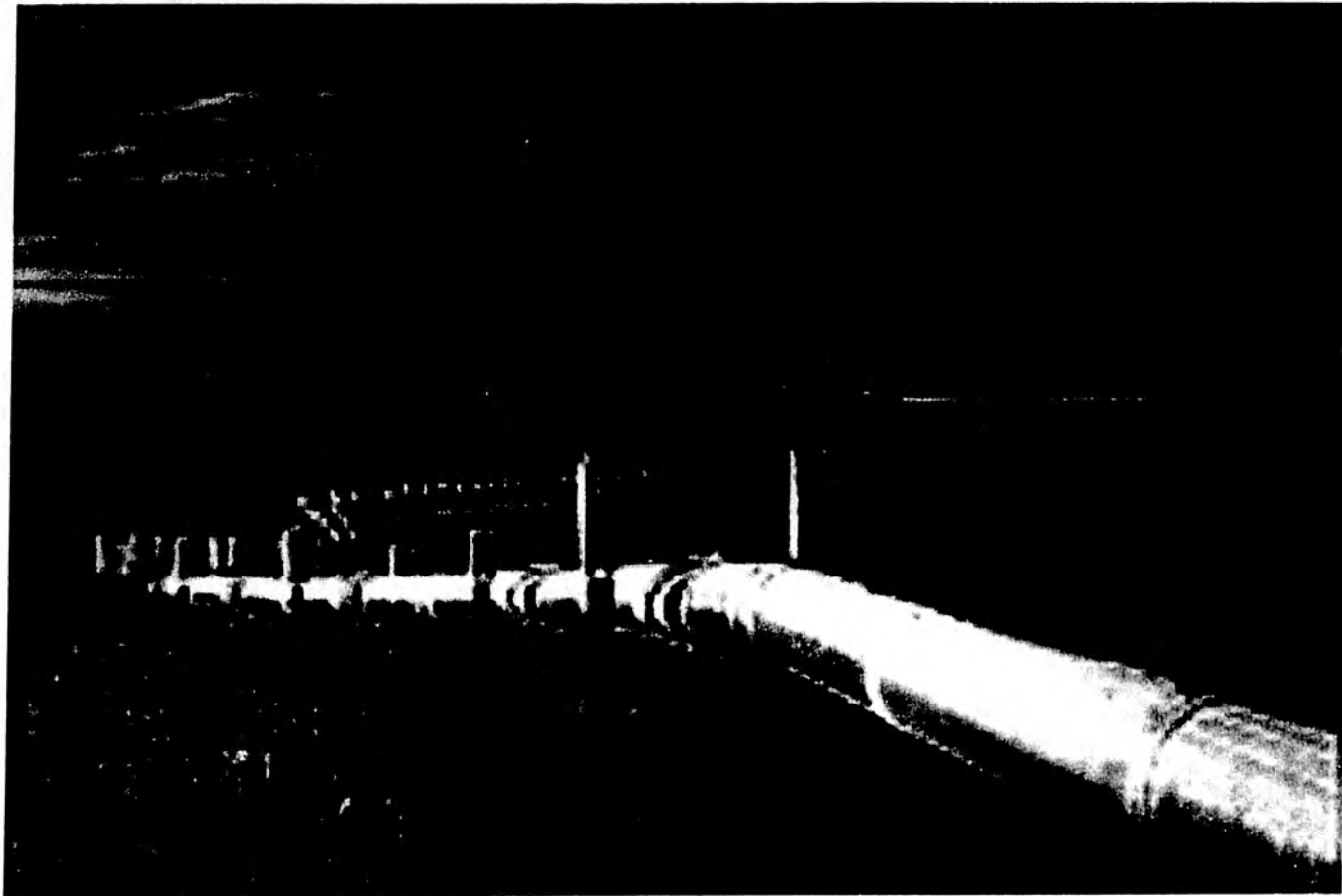
What is the Trans-Alaska Gas System (TAGS) Project?



✓ Gas conditioning on the North Slope



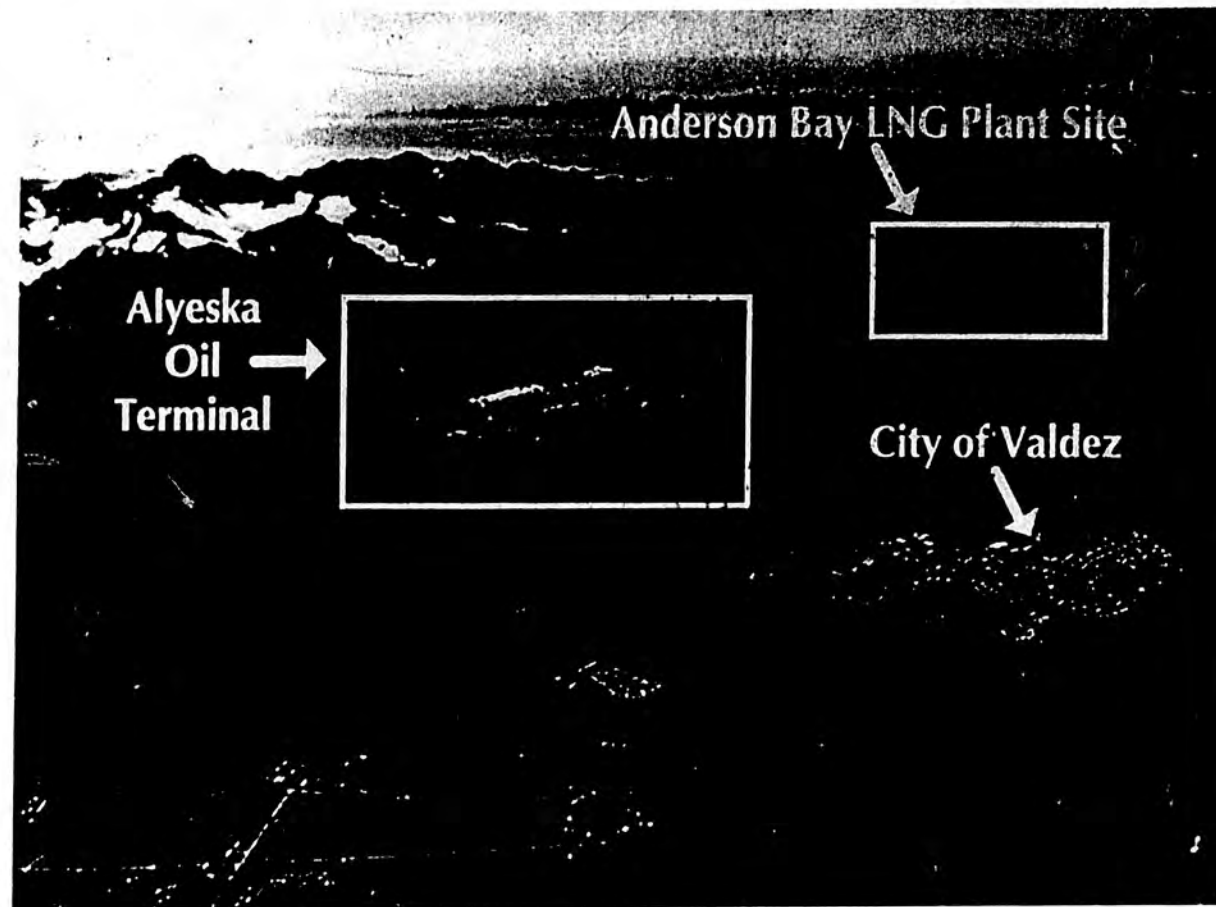
✓ Pipeline route to Valdez



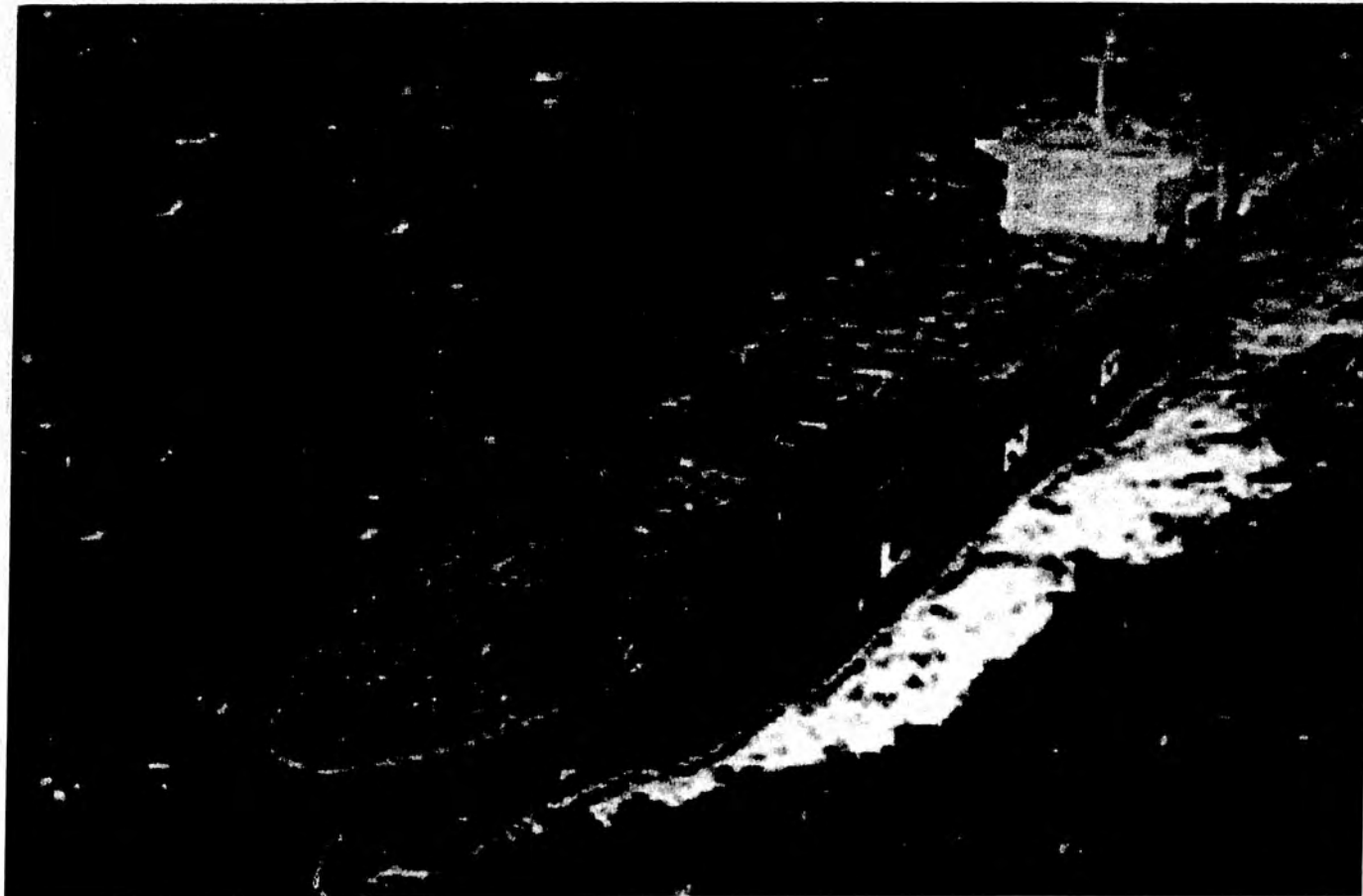
TAGS is in the existing,
dedicated pipeline corridor



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

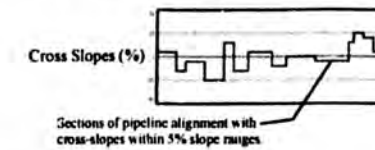
(Cont'd)

- ✓ 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)
Hfi	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

NOTICE

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, made or disclosed except as authorized in writing by Yukon Pacific Corporation.

Abbreviations and Symbols

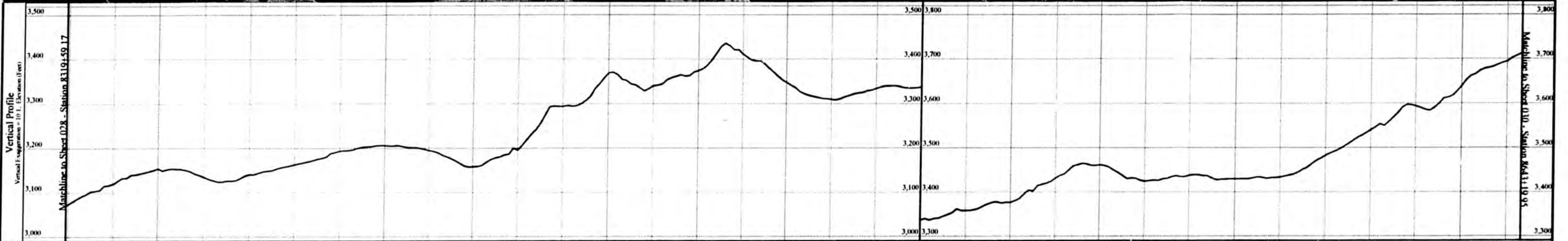
None
Civil Construction Typical Details
Civil Construction Typical Details

No.	DATE	REVISION	BY	APP.
0	12-3-99	Issued for Approval	HMU	KJM

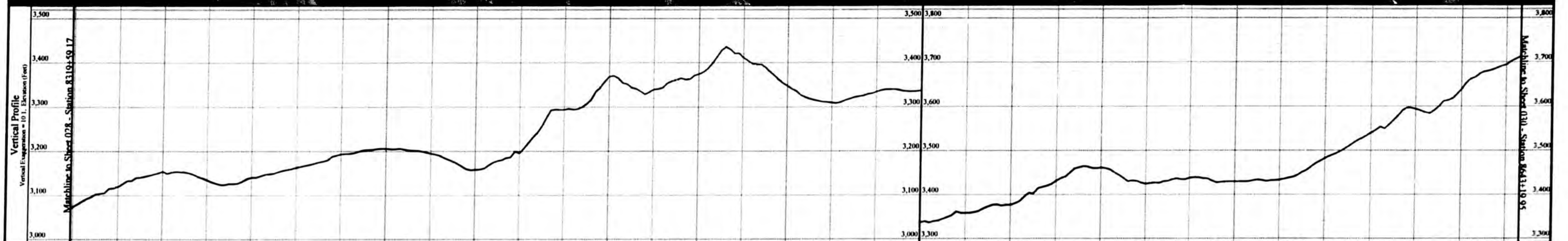
PAC
HMU
KJM
Michael Baker & Inc.
241063055

	TRANS-ALASKA GAS SYSTEM NATURAL GAS PIPELINE
	PRUDHOE BAY TO ANDERSON BAY

Not To Scale
Not To Scale
February 1, 2000
N/A
Sheet 01 of 05



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 Ht. Pst.																																	
Thaw Set Pst.																																	
Moisture Cont.																																	
Terrain EP																																	



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
X Slopes (%)																																	
Workpad Type																																	
Ditch Type																																	
TEP																																	
Wall Thickness																																	
CS, Vhs, SDA																																	
Foreign X-rings																																	
Water X-rings																																	
Terrain/Veg																																	
Cont. Season																																	
Hydrotest Sect.																																	

Trans-Alaska Gas System Capital Costs (\$US year 2000)

		START-UP	EXPANSION	EXPANSION
			I	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

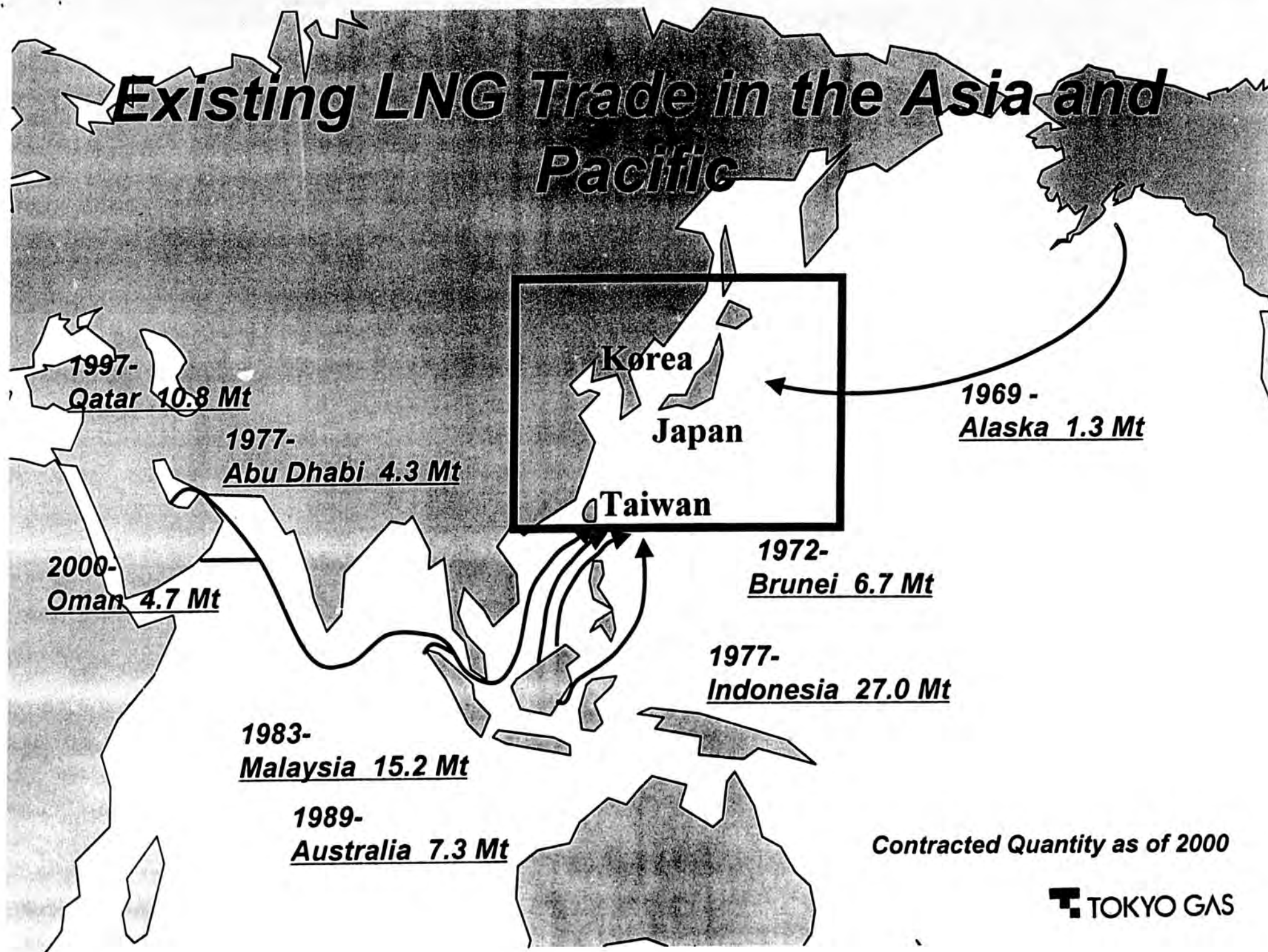
- Similar to the overland pipeline options, increasing the size of the TAGS project (4 bscfd) provides economies of scale to help Alaskan gas compete for the North American LNG/gas market

- 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

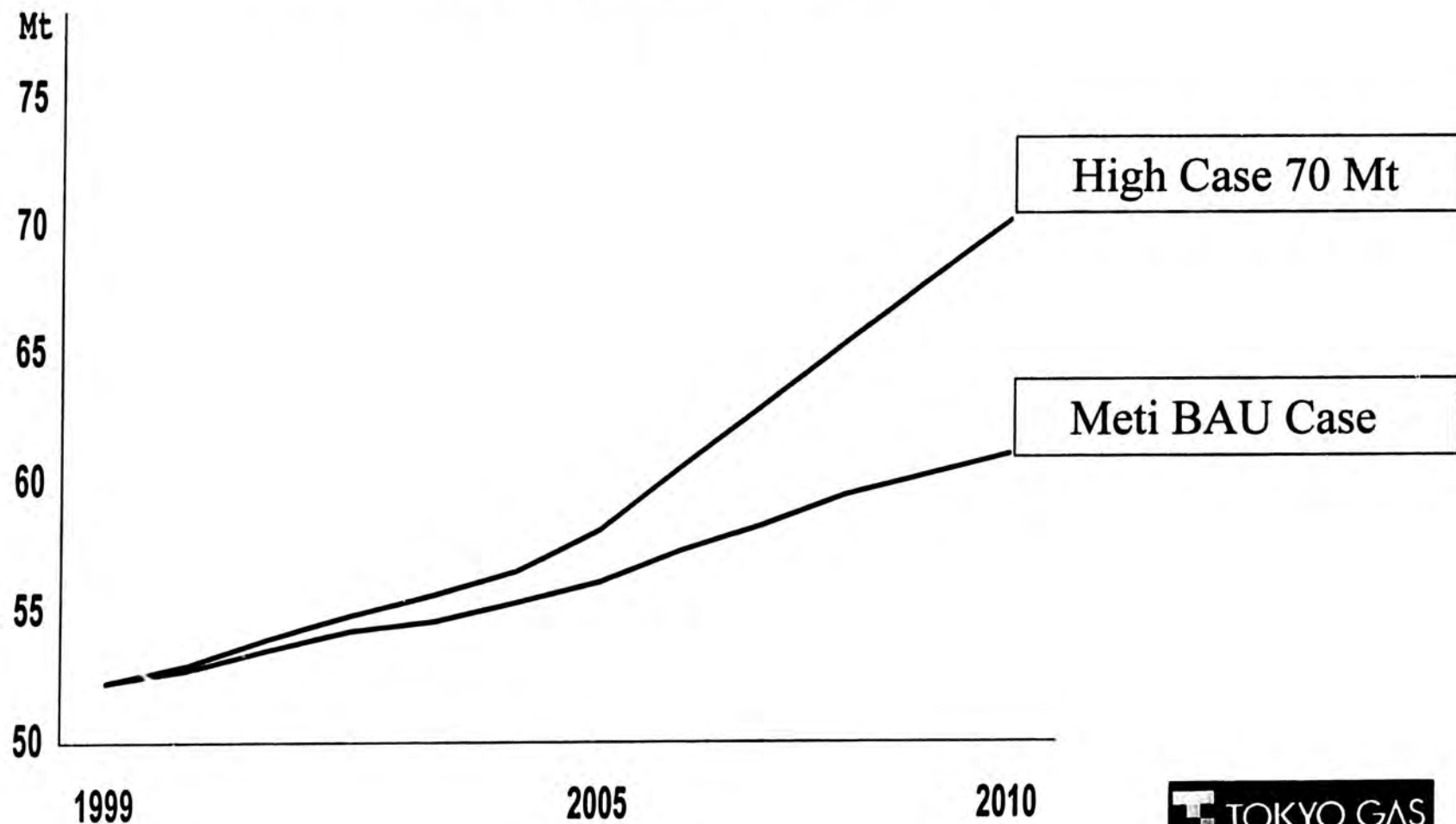


Contracted Quantity as of 2000

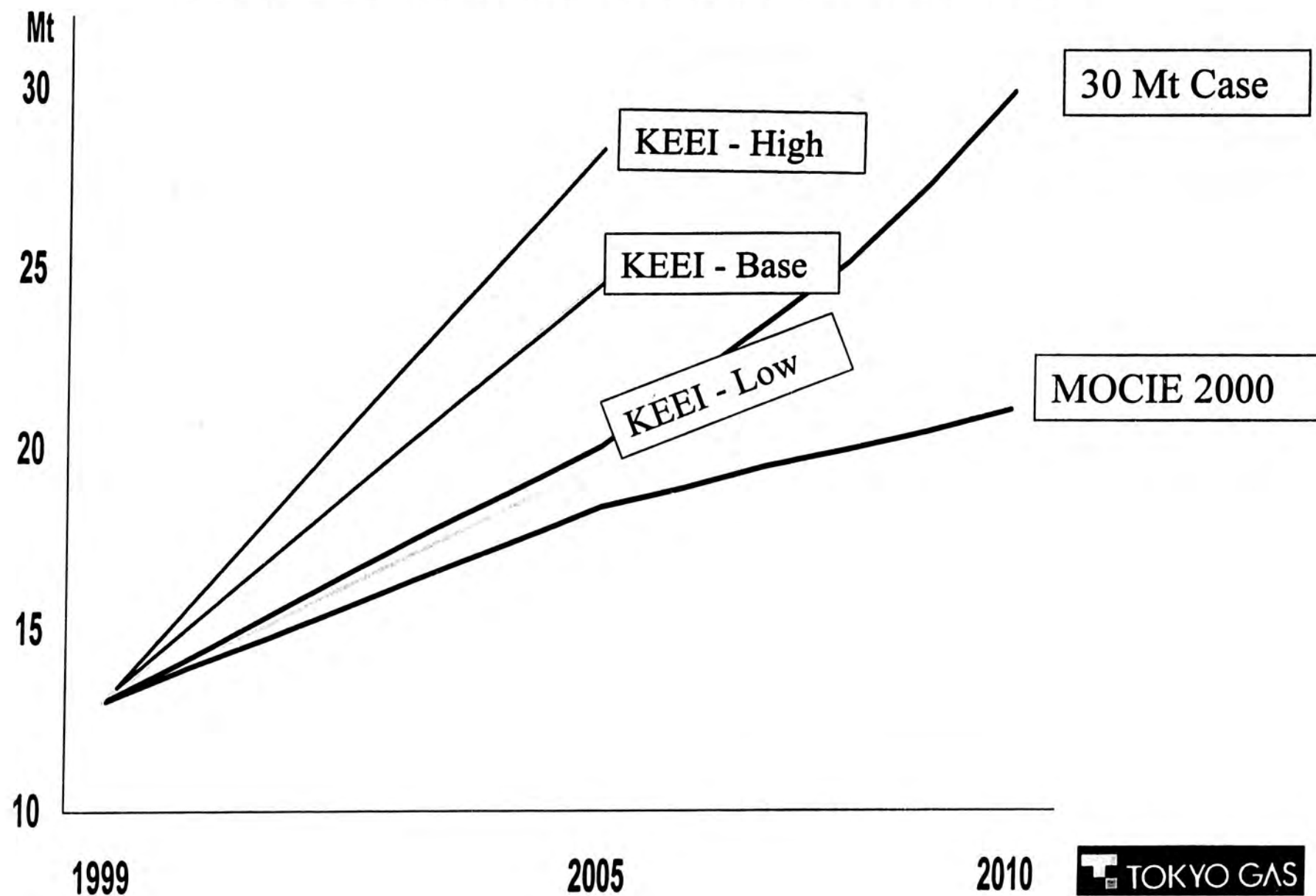
 TOKYO GAS

LNG Demand Outlook – Japan

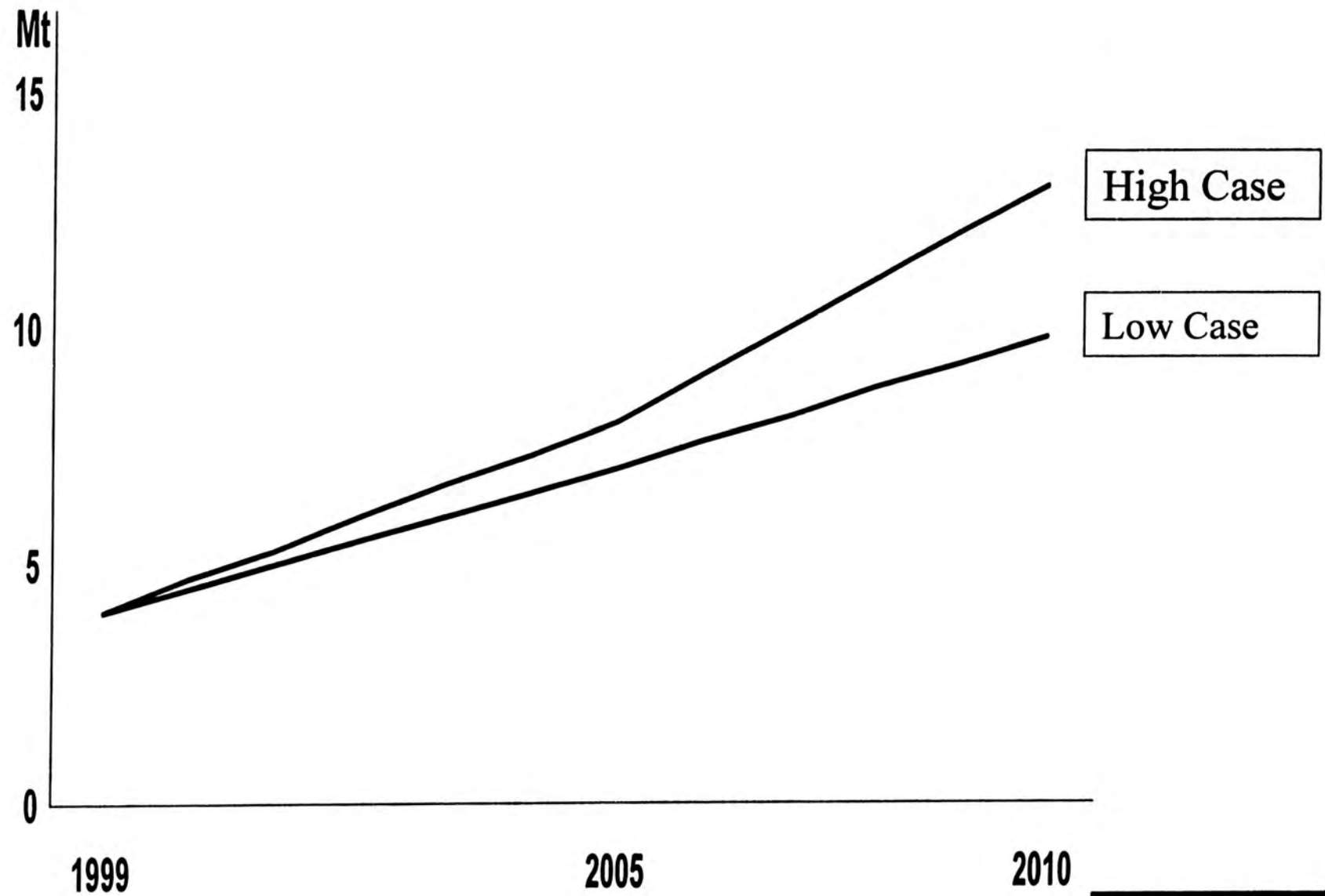
- Moderate energy demand growth - 1.1%
- Slow Development of Nuclear Power
- Increased concern on GHG emission



LNG Demand Outlook – Korea

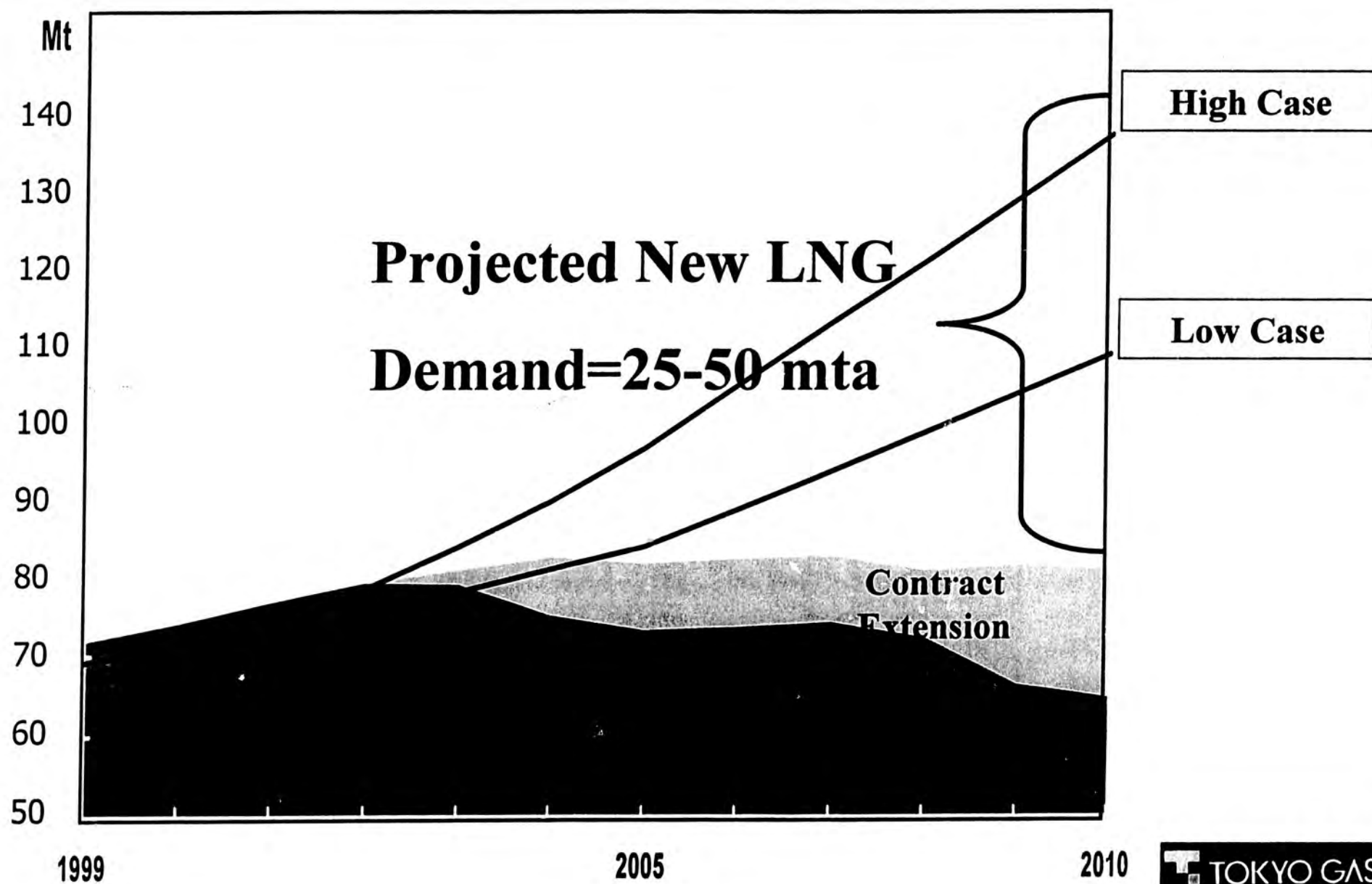


LNG Demand – Taiwan

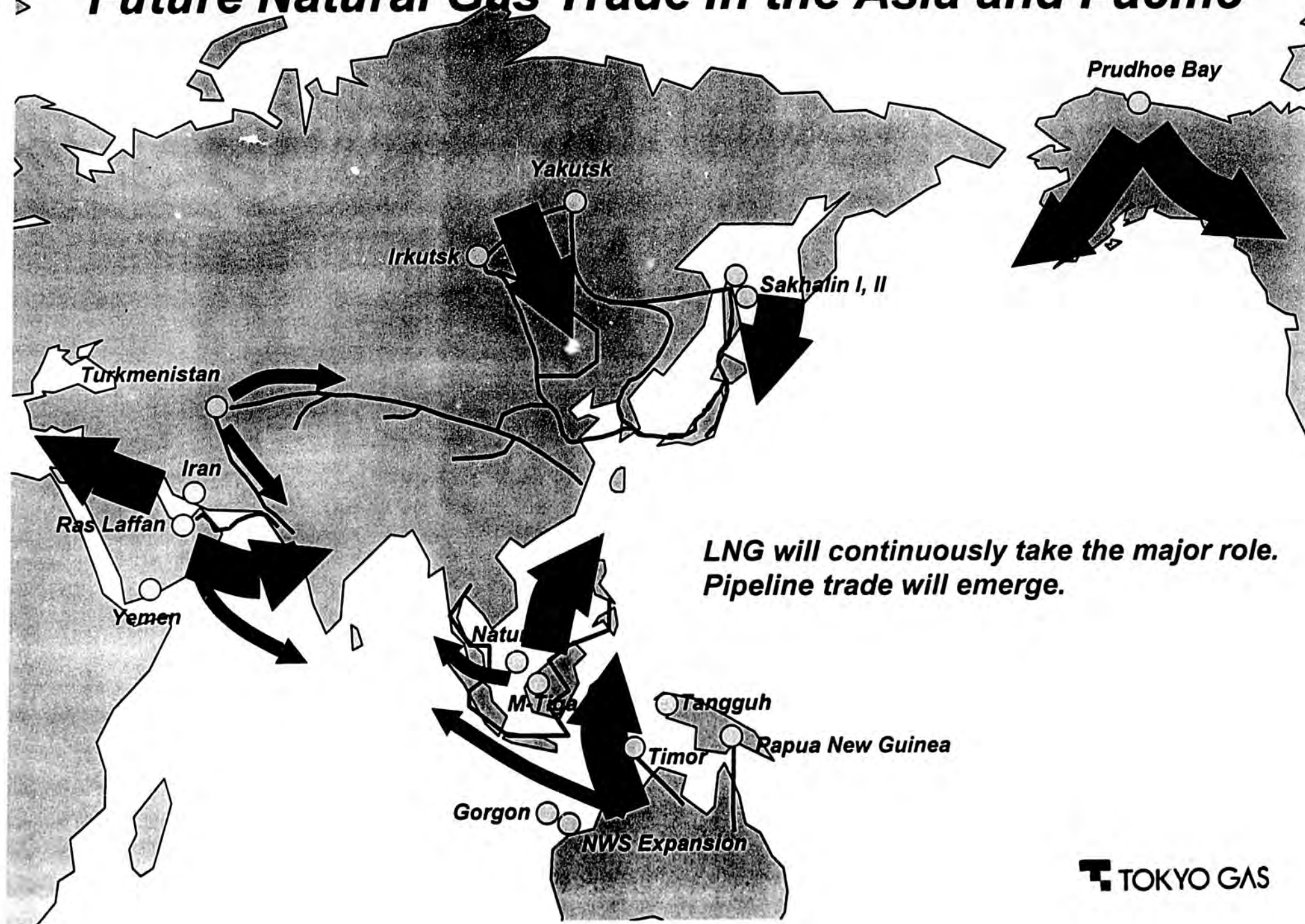


ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672
2947 SCOMM 129: JOINT COMMITTEE ON NATURAL GAS PIPELINE, 2001-02

LNG Demand Outlook in Asia and Pacific



Future Natural Gas Trade in the Asia and Pacific



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

<u>Buyer</u>	<u>Seller</u>	Jan. '01 <u>\$/mmBtu</u>
Japan	Abu Dhabi	4.81
	Alaska	4.54
	Australia	4.89
	Brunei	4.65
	Indonesia	4.98
	Malaysia	4.80
	Oman	5.17
	<u>Qatar</u>	<u>5.05</u>
	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

	<u>Low</u>	<u>High</u>
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 January 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	<u>1.14</u>
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 [$\$0.40 \times 60\% \times (8-6)/8$].

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 ($42\% \times (1-0.33) = 28\%$ 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 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.

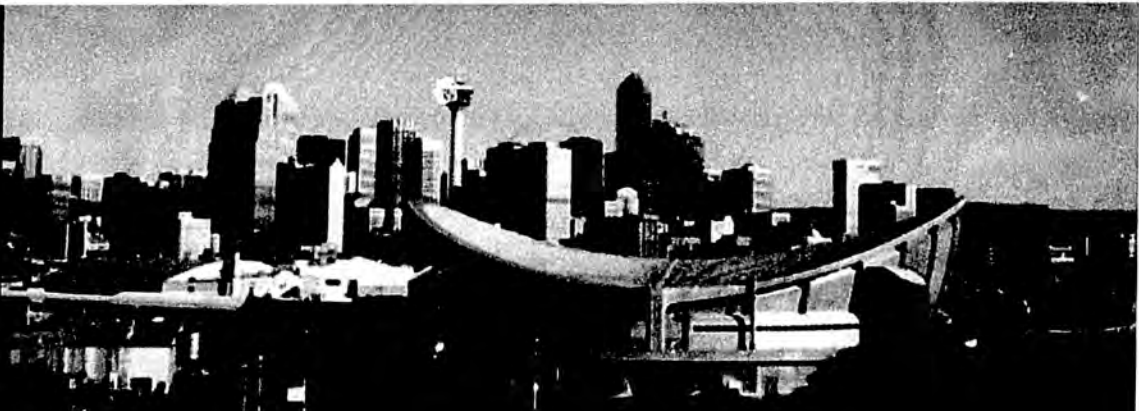


***Duke
Energy***

*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



- 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?

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

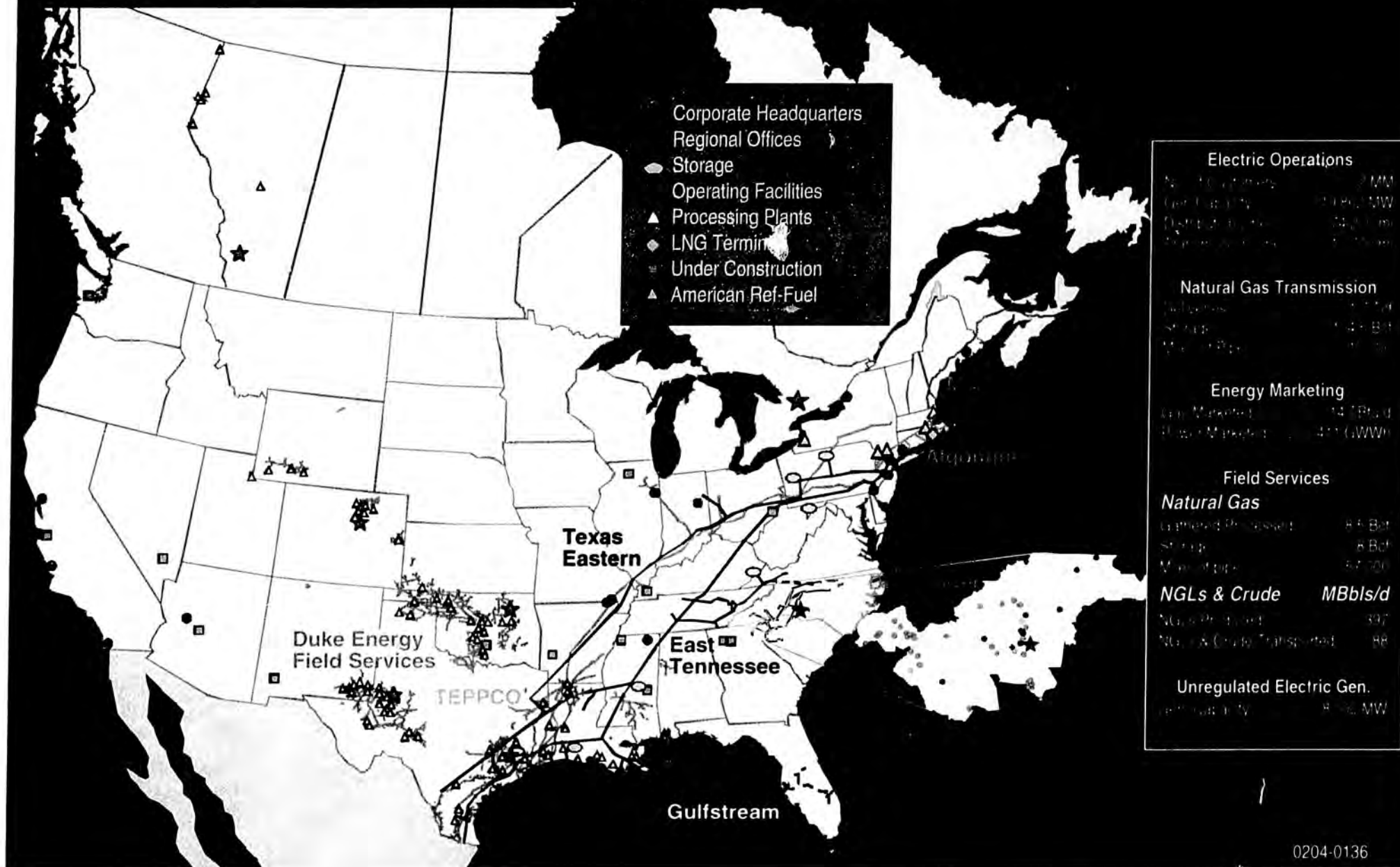
#2 gas marketer in U.S.

#3 power marketer in U.S.

30,000 megawatts of generation

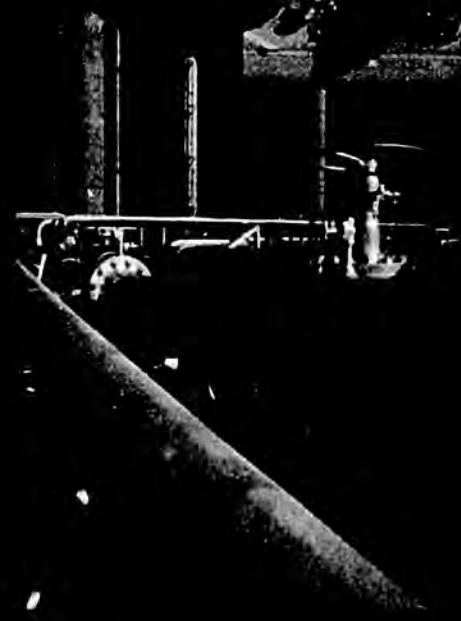
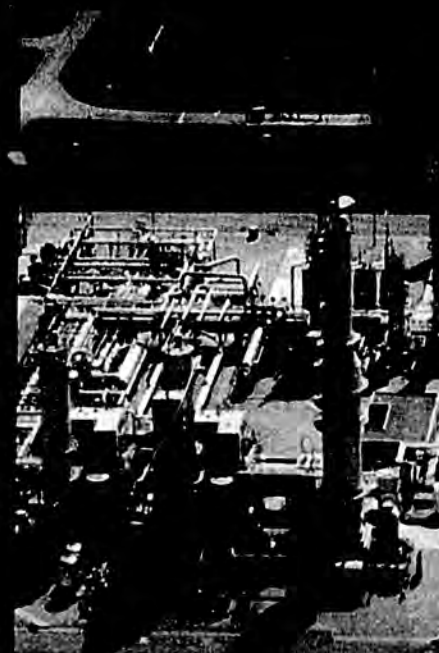
Current Duke Energy North America Operations

**Duke
Energy**



Duke Energy Gas Transmission

Gas Transmission —
Connecting supply and
high-growth markets



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Duke Energy Acquisition of Westcoast Energy

**Duke
Energy**

- ① Who is Duke Energy?
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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

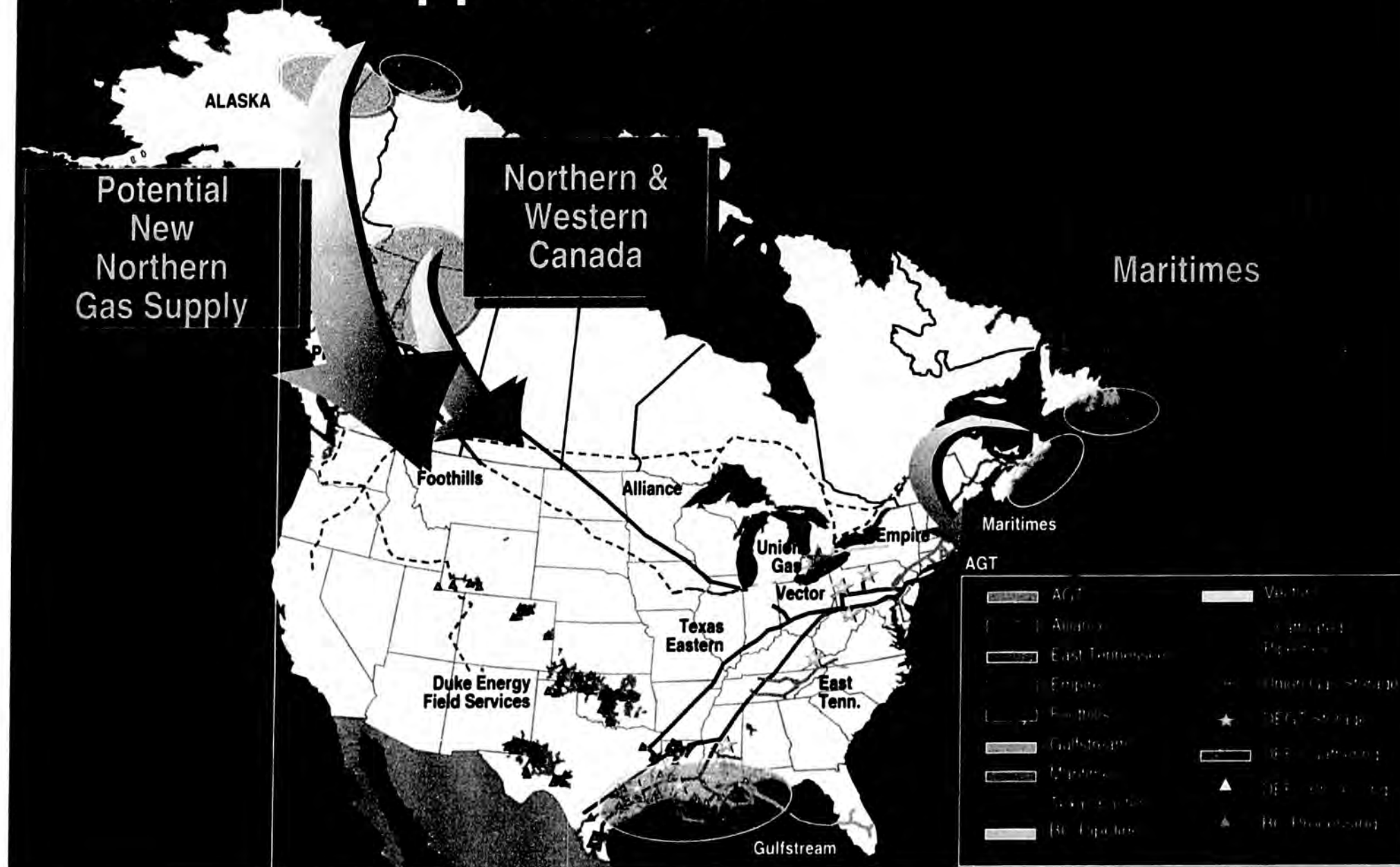
Duke Energy & Westcoast Energy Combined Energy Transmission System

**Duke
Energy**



Looking Forward — Growth Opportunities

**Duke
Energy**



Duke Energy Acquisition of Westcoast Energy

**Duke
Energy**

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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

Duke Energy Acquisition of Westcoast 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



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!



10 Keys to Success

- 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



Duke Energy Acquisition of Westcoast 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