ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

Official Business

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

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

MEMORANDUM

To: Joint Committee on Natural Gas Pipelines

From: Senator Torgerson, Chair

Date: February 12, 2002

Re: Hogan & Hartson report on federal legislative developments

This memorandum provides a brief description of federal legislative activities that are on the immediate horizon, including the Senate's consideration of a comprehensive energy bill. There was no activity from last week to report on.

I. Senate Energy Legislation

The Senate's consideration of a comprehensive energy bill, S. 1766 (or a revision of this bill), may begin as early as February 14, after the Senate has completed action on a massive agricultural policy bill that is currently on the floor. However, even if the Senate is able to begin consideration of the energy bill this week, most of the substantive amendments and votes are likely to be delayed until the Senate returns from its week long Presidents Day Recess, the week of February 25. Senator Kerry (D-MA) and others have promised a filibuster if ANWR drilling provisions are added to the bill, and Senator Murkowski (R-AK) has promised a filibuster if the bill does not contain such a provision. There is always the possibility that these and other controversial issues might prevent final passage of an energy bill in the Senate.

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A. Tax Issues

Leading up to the Senate's debate of the energy bill this week, several Senate Committees will consider topics that are not currently included in S. 1766, but which could be added during Senate floor consideration or as part of Senate Majority Leader, Tom Daschle's (D-SD) revisions to the bill. One of these components is the energy tax provisions, which are expected to be marked-up by the Senate Finance Committee on Tuesday or Wednesday of this week. The comprehensive energy bill approved by the House, H.R. 4, contains approximately $35 billion in tax incentives for energy production and conservation. Although we do not know for certain what specific provisions will be included in the Senate's bill, the following provisions, which are also included in H.R. 4, are being given serious consideration.

- A proposal that would establish a statutory 7-year recovery period and class life of 10 years for natural gas gathering lines. In addition, the proposal would provide that there would be no adjustment to the allowable amount of depreciation for purposes of computing a taxpayer's alternative minimum tax with respect to such property.

- A proposal that would establish a statutory 10-year recovery period and a class life of 20 years for natural gas distribution lines. In addition, the proposal would provide that there would be no adjustment to the allowable amount of depreciation for purposes of computing a taxpayer's alternative minimum tax with respect to such property.

- A proposal that would extend the section 29 tax credits for certain non-conventional fuels produced at wells placed in service after the date of enactment and before January 1, 2007. Qualifying fuels would be oil from shale or tar sands, gas from geopressured brine, Devonian shale, coal seams or a tight formation. The value of the credit would be $3.00 per barrel (or BTU oil barrel equivalent) for production in 2001 and 2002 and would be indexed for inflation beginning in 2003. The proposal would also allow the tax credit for production from certain existing wells (any well drilled after December 31, 1979 and before January 1, 1993). Landfill gas sold to a third party from facilities placed in service after June 30, 1998 and before January 1, 2007 would also be eligible for the section 29 credit. The credit would be capped at production equal to a daily average of 200,000 cubic feet of gas (or barrel or oil equivalent).

B. Pipeline Safety

Senator McCain (R-AZ) intends to offer the provisions of S. 235 as an amendment to the Senate's comprehensive energy bill. S. 235, the Pipeline Safety Improvement Act, passed the Senate February 8, 2001, by a vote of 95-0. This bill would, in part, reauthorize the Pipeline Safety Act through 2004, increase penalties for safety violations, and require pipeline operators to test the adequacy of pipelines at least every five years. Senator McCain believes that attaching S. 235 to the comprehensive energy bill would increase its changes of clearing Congress, since the House has been slow to act on similar legislation.

The Chairman of the House Transportation and Infrastructure Committee, Representative Don Young (D-AK), along with the Chairman of the Energy and Commerce Committee, Representative Billy Tauzin (R-LA), introduced a new pipeline safety bill, H.R. 3609, on December 20, 2001. In general, H.R. 3609 is much less prescriptive then S. 235 and does not contain the five-year testing mandate that is found in the Senate bill. A hearing on pipeline safety issues before the House Transportation and Infrastructure Committee is scheduled for February 13.

C. Other Provisions in S. 1766

- Provisions that would establish an expedited process for FERC to consider and act on any application to construct a pipeline to transport Alaska natural gas. The bill's Alaska pipeline provisions also include restrictions on court venue, deadlines for performing environmental impact statements, and an authorization for federal loan guarantees.

- Provisions that would prohibit the listing of an operating natural gas pipeline under the National Historic Preservation Act, unless the owner consents to the listing.

- Provisions that would require the development of an interagency memorandum of understanding to expedite environmental review and permitting of pipeline projects.

II. Climate Change

The Bush administration is expected to release its long-awaited policy on climate change this week. Published news reports indicate that the policy will emphasis the need for more research on both the science of understanding climate change and the means of mitigating its effects. The policy is also expected to recommend flexible, gradual goals for greenhouse gas reductions. The Economic Report of the President, released February 5, 2002, briefly describes a flexible approach for controlling greenhouse gases that would index emission targets to economic output or other measures of economic activity. Another approach described in the report would express targets or goals in terms of greenhouse gas emission intensity (*i.e.*, the amount of emissions per unit of economic activity).

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12 Proposals on Federal Legislation

Proposal # 1

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress reaffirm that the Alaska Natural Gas Transportation Act (ANGTA) is the prevailing law with respect to a transportation system for delivery of Alaska natural gas to Alaska, the contiguous States, and other markets, and the construction and initial operation of that system.

The Joint Committee on Natural Gas Pipelines also respectfully requests that Congress allow certain amendments to ANGTA to modernize the act without changing the basic nature and general route of the approved transportation system or otherwise preventing or impairing in any significant respect the expeditious construction and initial operation of the transportation system.

Justification for Proposal # 1

Before the enactment of ANGTA there were three competitive proposals for an Alaska Natural Gas Transportation System. Specifically those proposals were:

1) the Arctic Gas Project, which proposed an overland pipeline extending from Prudhoe Bay, across the North Slope of Alaska to the Canadian Mackenzie Delta and thence southerly through Canada to the lower forty-eight states;
2) the El Paso LNG Project, which proposed an overland pipeline extending from Prudhoe Bay to Southern Alaska, where the gas would have been liquefied and transported by tankers to terminals in the western United States; and
3) the Alcan Pipeline Project, referred to in Canada as the Alaska Highway Pipeline Project, which proposed an overland pipeline

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extending from Prudhoe Bay to Fairbanks, Alaska, and thence southeasterly through western Canada to the lower forty-eight states.

All of these proposals were filed under the Natural Gas Act, debated by FERC, and Congress passed ANGTA, which authorized the President to select a route. The President then approved the ALCAN route and entered into a treaty with Canada, which were later confirmed by Congress. The Canadian Parliament also passed the Northern Pipeline Act, the equivalent of ANGTA. ANGTA was never repealed. In fact, in 1992 the federal inspector recommended that ANGTA be abolished, but Congress rejected that notion.

Proposal # 2

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress adopt provisions that prohibit the over-the-top route through the Beaufort Sea as a pipeline route.

Justification for Proposal # 2

- The Alaska Legislature has banned this route in Senate Bill 164.
- The House of Representatives in Congress has adopted an amendment in the Energy Bill to ban this route.
- This route seriously decreases the benefits Alaskan's will receive from the development of natural gas.
- The North Slope Borough and the Alaska Eskimo Whaling Captains oppose this route.

Proposal # 3

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress create a mechanism for allowing the transparent and fair distribution of the costs allowed to be included in the tariffs associated with a conditioning plant(s).

Justification for Proposal # 3

Other producers will likely discover gas downstream from access to a conditioning plant in Prudhoe Bay that will require them to construct an additional conditioning plant. These producers will need to be treated fairly with regard to tariffs to encourage development and exploration of all North Slope gas resources.

Proposal # 4

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to eliminate the Dempster-Lateral route from provisions in ANGTA, if necessary.

Justification for Proposal # 4

The original version of ANGTA included approval for the construction of a Dempster-Lateral pipeline to deliver natural gas to market from the Northwest Territories. The Northwest Territories has developed plans for their own pipeline route to Alberta, making the Dempster-Lateral line obsolete.

Proposal # 5

The Joint Committee on Natural Gas Pipelines respectfully requests that the Congress pass legislation that limits tariff charges for prior work to compensation for work done that does not have to be duplicated and which is deemed appropriate to the current transportation system.

Justification for Proposal # 5

The current owner of the authorizations under ANGTA is Foothills Pipeline Ltd. Previously, Foothills had several partners, which over time have withdrawn from the partnership. The withdrawn partners spent funds in support of the ANGTA route and have filed documents with the FERC to include recovery of those costs in any tariff for transportation of Alaska natural gas. Foothills has been negotiating with the withdrawn partners to resolve this outstanding liability. However, those negotiations have not been successful to date.

Foothills and its partners should be compensated for the work done in furtherance of the ANGTA system that does not need to be duplicated. If the work needs to be redone or modernized, they should not be entitled to collect for the funds previously expended. Accordingly, the Joint Committee should support this request.

Proposal # 6

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress pass legislation to assure that Alaska have fair and reasonable access to gas produced within the State and to create a joint board consisting of members appointed from the Federal Energy and Regulatory Commission and the Regulatory Commission of Alaska to recommend access and tariffs that affect the state of Alaska.

Justification for Proposal # 6

Unlike the Trans-Alaska Transportation System for oil, the Natural Gas Act does not provide for the Regulatory Commission of Alaska to set rates for gas used in Alaska. Although section 13(b) of ANGTA provides that the state is authorized to ship its royalty gas on the approved system for use within Alaska and to withdraw such gas from the interstate market for use within Alaska, it does not deal specifically with how Alaska delivery points along the line will be approved. Access to gas is necessary for social and economic development of Alaska. Alaska's regulatory commission should be part of a team that determines how intra-state access and rates are determined.

Proposal # 7

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to develop a formula that would allow for the setting of different tariff rates for natural gas distribution points along the route. (HUBS)

Justification for Proposal # 7

Alaska is studying different proposals for usage of natural gas within the state, including several proposals for LNG facilities, a petrochemical plant, several GTL plants, and in-state usage by communities. It is important to be able to set the tariff at different rates to allow these take off points.

Proposal # 8

The Joint Committee on Natural Gas Pipelines respectfully requests that the Congress pass legislation to assure that gas producers that do not have an ownership interest in the pipeline have fair and reasonable access to space on the pipeline and the ability to obtain expansion capacity of the pipeline.

Justification for Proposal # 8

ANGTA originally precluded the Producers from participating in the ownership of the gas pipeline. In 1981, a waiver was sought and obtained by President Reagan to permit the Producers to have an ownership share in the pipeline. Their participation, however, had to be approved by the FERC and could be approved only after consideration of the advice from the Attorney General and upon a finding by FERC that the participation would not (a) be inconsistent with the antitrust laws or (b) in and of itself create restrictions on access to the transportation system for non-owner shippers or restrictions on capacity expansion.

Alaska has much more gas than that contained in known fields. Current estimates provide that there is greater than 100 tcf of gas undiscovered on the Alaska North Slope. Currently, companies are considering exploring for such gas. If discoveries are made, that gas will need access to the pipeline on fair and reasonable terms. If significant discoveries are made after the initial capacity is filled, the pipeline will need to be expanded and any expansion request needs to be determined on fair and reasonable terms. Accordingly, the law must be clear that the FERC has the authority to make such determinations.

Proposal # 9

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to approve a provision for project labor agreements.

Proposal # 10

The Joint Committee on Natural Gas Pipelines respectfully requests Congress to approve a preference for qualified Alaskan businesses for the construction and maintenance of a natural gas pipeline.

Proposal # 11

The Joint Committee on Natural Gas Pipelines respectfully requests that Congress pass legislation that prohibits tax incentives for LNG from sources outside of North America.

Justification for Proposal # 11

The President and Congress have recommended a variety of incentives as part of a national energy policy. Alaska natural gas is in competition with LNG imported from foreign sources to supply gas to the lower 48 states. It is the policy of the United States to reduce dependence on foreign energy sources. Accordingly, Congress should not pass any law that gives tax incentives to facilities importing LNG from sources outside North America. Rather, Congress should enact incentives that benefit production from the frontier areas of the United States, including Alaska. Otherwise, United States gas in frontier areas may be stranded.

Proposal # 12

The Joint Committee on Natural Gas Pipelines respectfully requests that the Congress pass legislation providing a tax incentive that allows for an accelerated depreciation schedule of seven years for Alaska natural gas brought to United States markets.

Justification for Proposal # 12

The President and the Congress has recommended a variety of incentives as part of a national energy policy. It is the policy of the United States to reduce dependence on foreign energy sources. Alaska has significant gas resources that can reduce that dependence and bring cleaner burning fuel to United States markets. However, the construction of a pipeline to the lower 48 would cost billions of dollars and involve significant risk. Accordingly, Congress should enact tax incentives, such as accelerated depreciation, investment tax credits, and downside price tax credits that benefit gas production from Alaska.

Alaska Gas and NGL—Economic Analysis of Value and Royalty

Report prepared for the Alaska Department of Natural Resources

Roger Riddlehoover and Barry Pulliam

Econon One Research, Inc
Los Angeles, California

January 2002

Economic Issues

•How are gas and NGL markets in North America structured today and how do they operate?

•What role will ANS production play in North American gas and NGL markets?

•What market factors are most important to determination of the value of ANS gas and NGL at the point of production?

•What market and economic factors are most important to determination of gas and NGL royalty values under the State's lease agreements with ANS gas producers?

U.S. Natural Gas Market

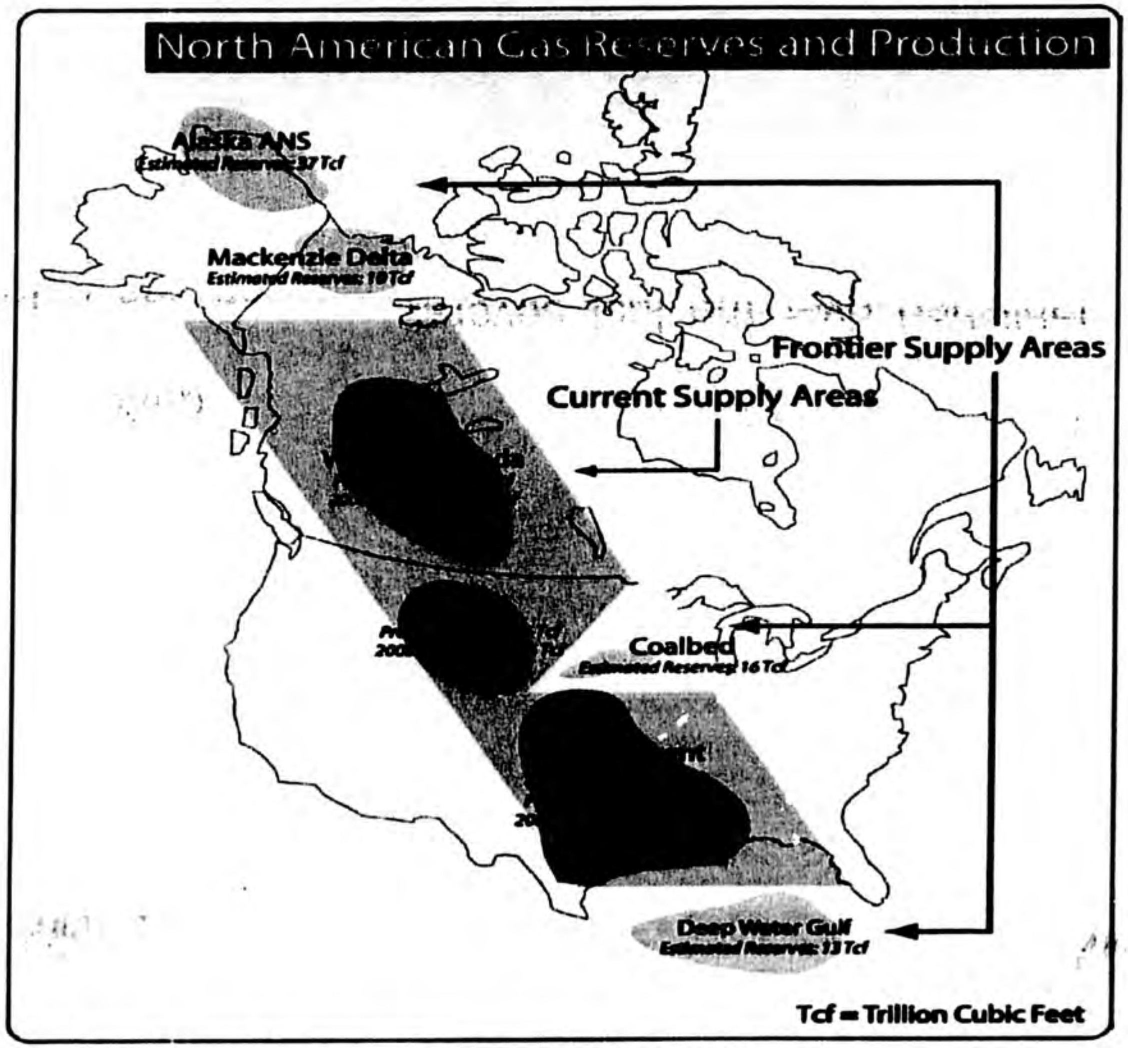
Deregulation of U.S. gas markets over the past 20 years has made them highly flexible and responsive to short-run changes in demand or supply conditions.

- less effective at long term planning for coordinated development of large new supply and infrastructure projects.
- gas prices are sometimes quite volatile.

Gas markets will continue patterns established over the last several years.

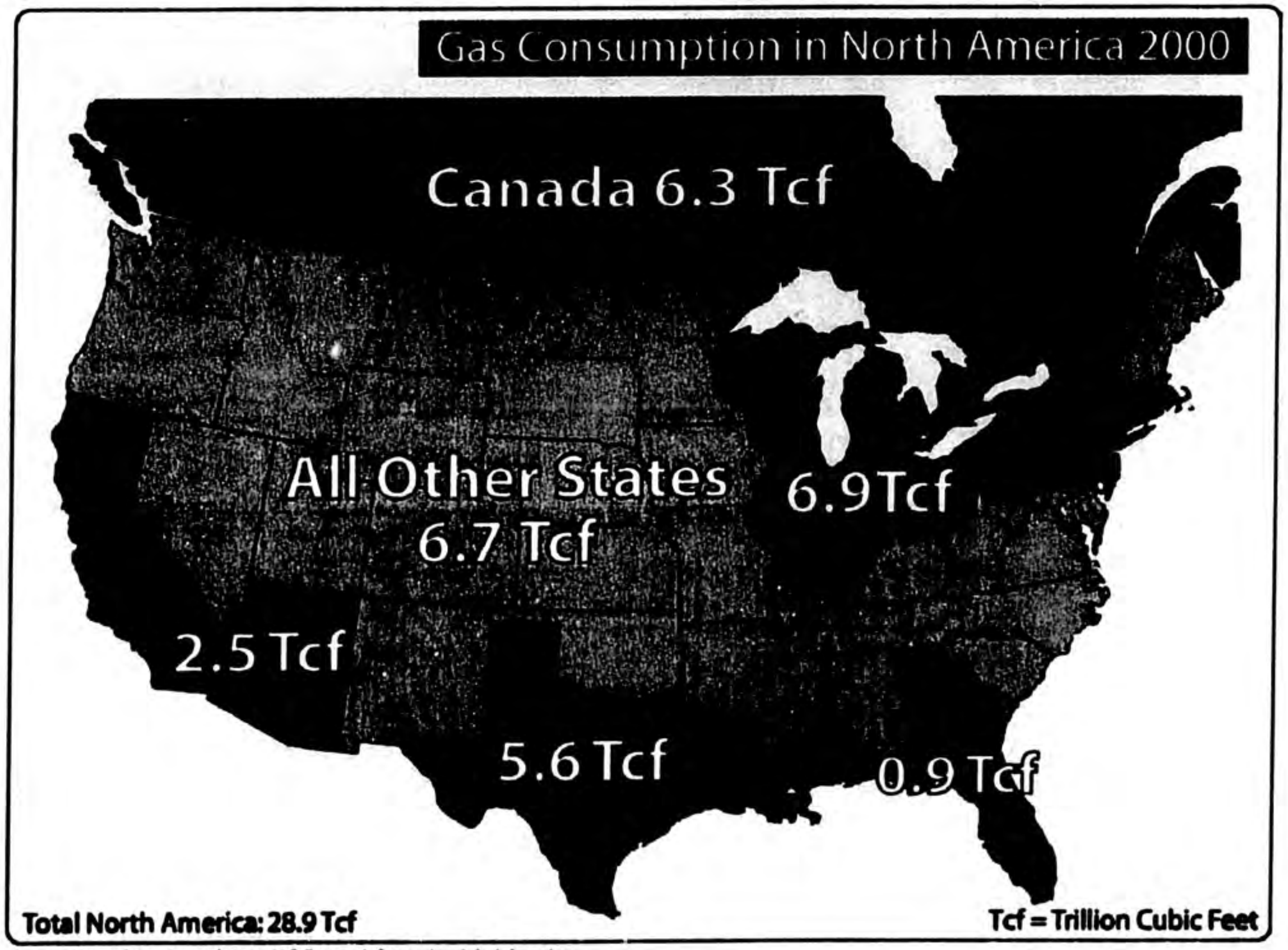
- Short, sometimes dramatic price swings
- Large increments of supply and infrastructure construction may alter price and flow patterns for months or years.

U.S. Natural Gas Supply



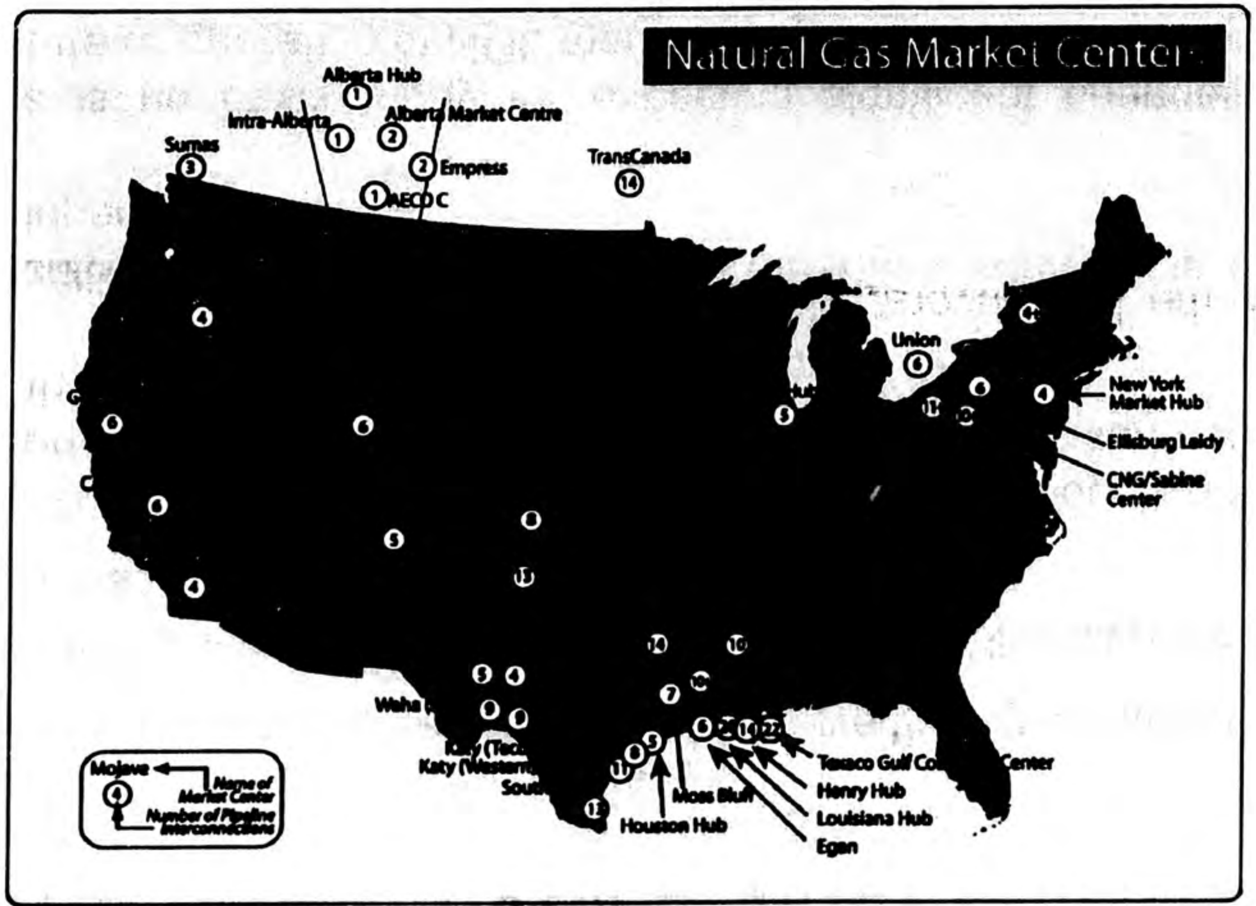
Sources: Potential Supply of Natural Gas in the United States, Potential Gas Committee, 2000.
Natural Gas Potential in Canada, 2001, Canadian Gas Potential Committee.
Natural Gas Monthly, March, 2001, U.S. Energy Information Administration.

U.S. Natural Gas Consumption



Source: Natural Gas Annual, 2000, U.S. Energy Information Administration

U.S. Natural Gas Market Centers



Source: FERC Policy Discussion Paper 99-01 (June 1999).

U.S. Natural Gas Liquids Market

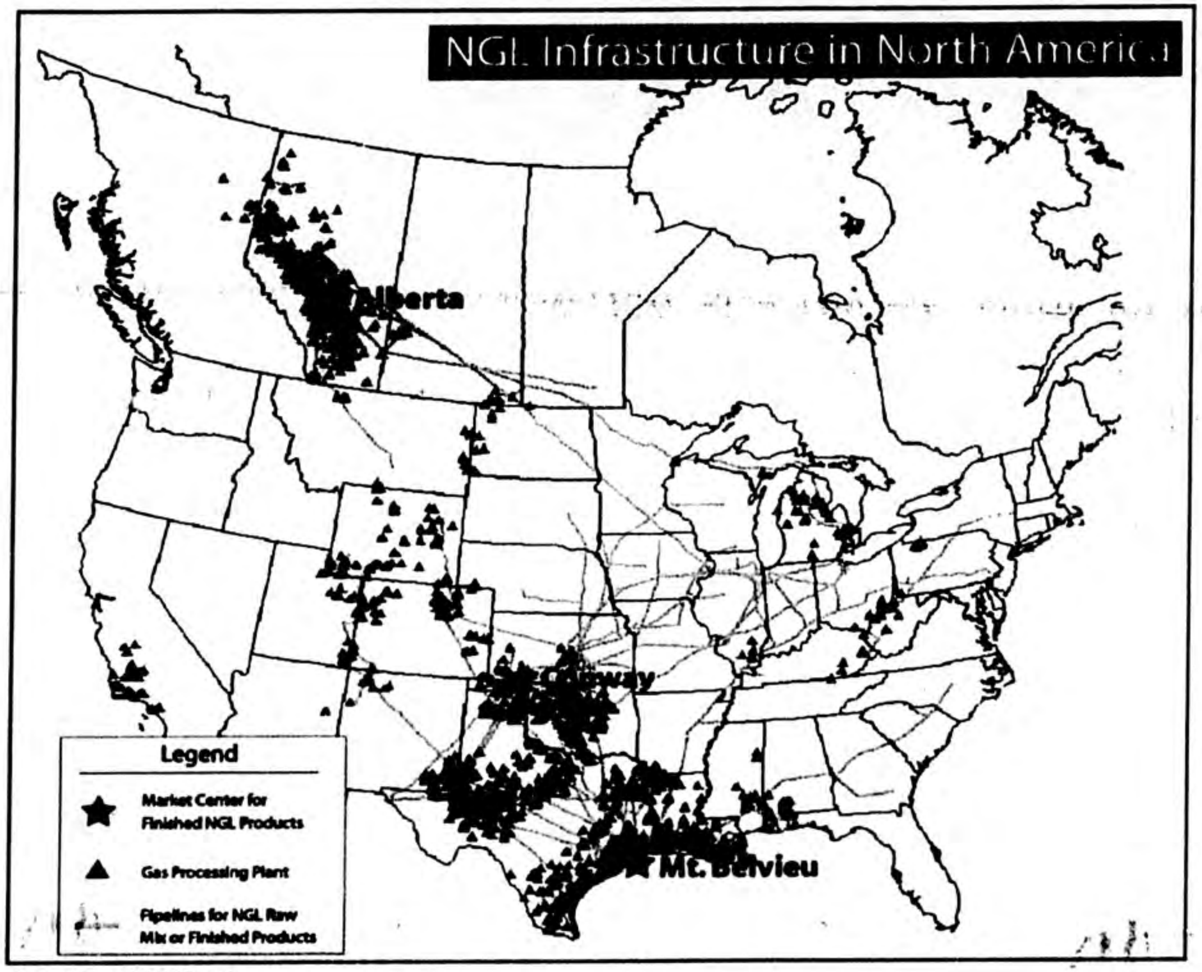
NGL markets are less flexible and responsive than gas markets.

- •Only a handful of NGL finished product trading centers, where transaction prices are set and reported.
- •Prices paid for raw-mix NGL at the point of production typically are set by deducting transportation and fractionation costs from these downstream market centers.

Information as to market rates paid for these services is not well developed or circulated.

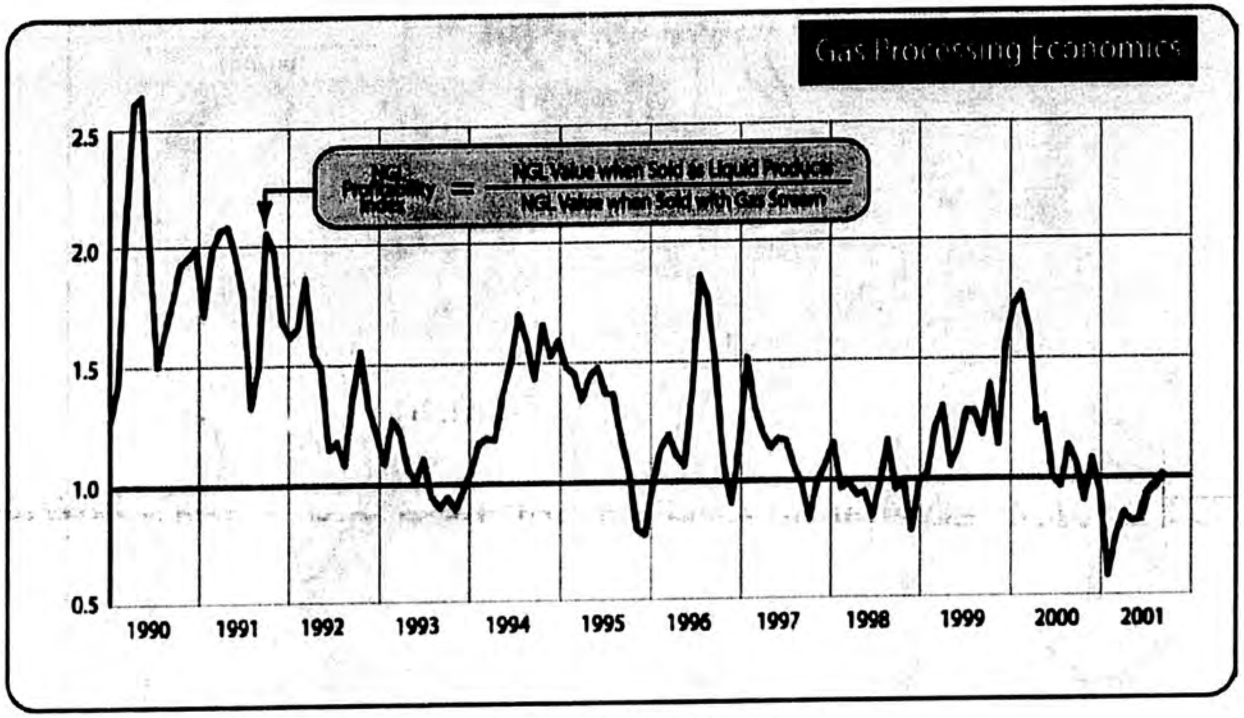
There is no basis today for expecting significant changes in the structure or operation of NGL markets in years to come.

NGL Processing and Market Centers



Source: Penwell MAPSearch.
http://www.mapsearch.com/pipelineFacility.cfm

Profitability of NGL Extraction



Notes: (1) NGL Value When Sold as Liquid Product = Mont Belvieu Composite NGL Price times two, a typical number of NGL Gallons in an Mcf of gas.

(2) NGL Value When Sold With Gas Stream = Henry Hub Price times 25%, a typical heat loss associated with NGL extraction from gas.

Source: Mont Belvieu Composite NGL Price: Gas Processors Report.
Henry Hub, Louisiana: Natural Gas Week.

ANS Natural Gas and NGL

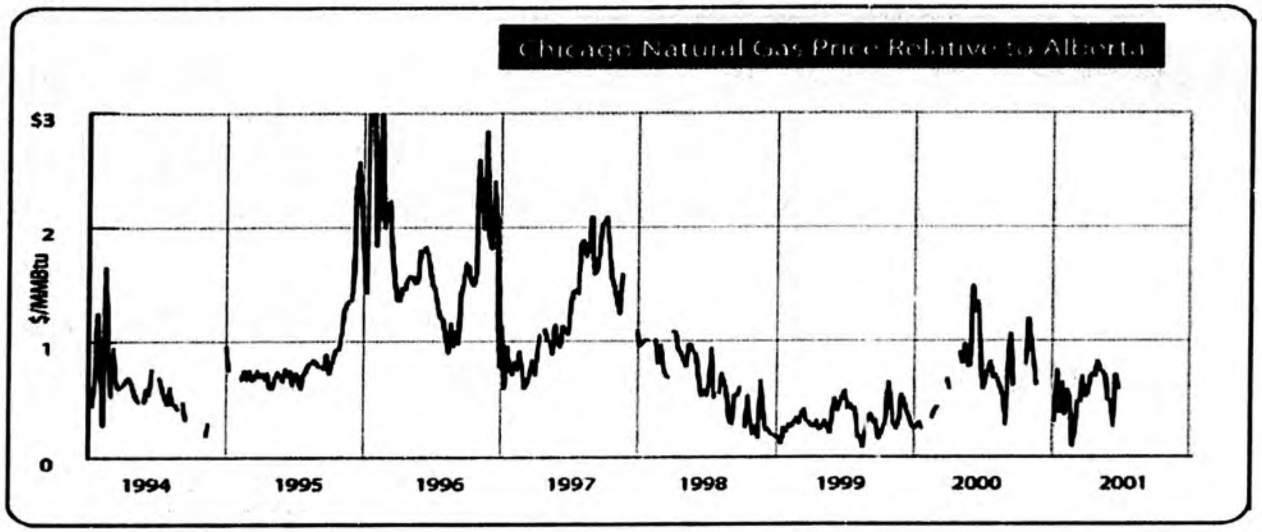
ANS gas and NGL are likely to enter North American markets via Alberta

- As a gas and NGL market center it has experienced wide price swings relative to other market areas.
- A stable and reliable market for gas and NGLs in Alberta will depend on the evolution of production within Alberta and pipeline projects downstream of Alberta.

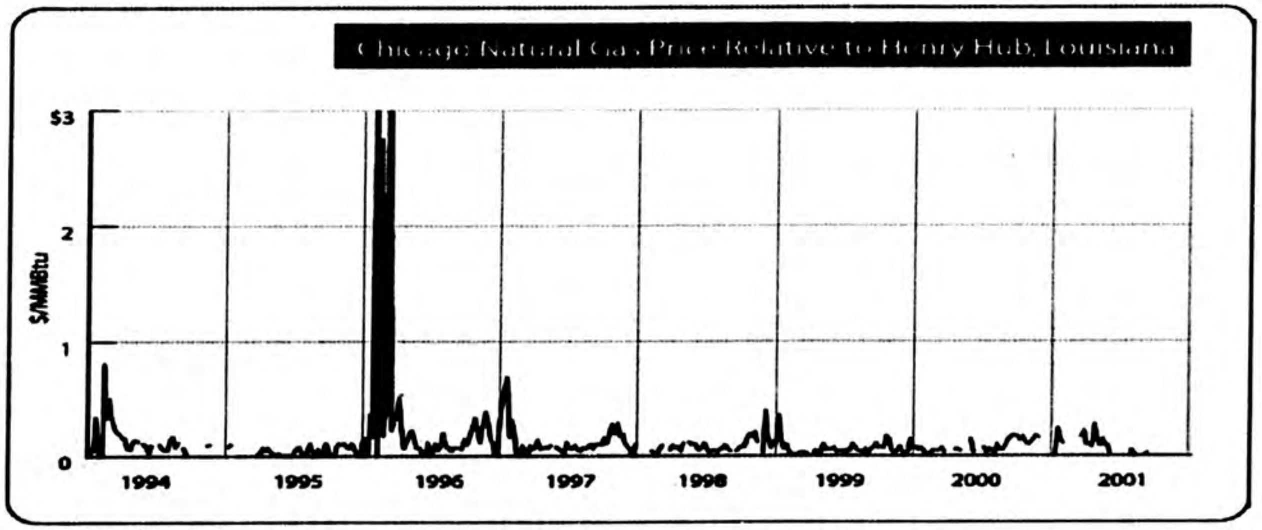
Delivery of ANS gas and NGL in the same pipeline will cost less than transporting them separately.

- Such a pipe, though long and large, will be economically similar to a field gathering system from the perspective of owners and users.
- There is not likely to be a flourishing secondary market for capacity on the ANS pipeline.

Valuation of ANS Gas and NGL



Source: Natural Gas Week.



Source: Natural Gas Week.

Royalty Valuation

Alaska's oil royalty experience provides a useful template for gas and NGL royalty.

- Like ANS crude oil, gas and NGL will be moved to destination markets far downstream.
- The wellhead value of ANS gas will be dependent upon market prices in Alberta and/or other major "nodes" on the North American gas grid and transport costs to those markets.

Royalty is an economic partnership with sharing of product or sharing of revenues.

Royalty Valuation

IT IS CRITICAL THAT PARTNERS SHARE INFORMATION.

During its initial years of production, ANS producers should share with the State information at their disposal concerning movement and sale of ANS gas and NGL.

- This will permit the State and producers jointly to understand how ANS gas is fitting into U.S. markets.
- The State and producers will be positioned to evaluate lower-cost alternative valuation methods that accurately mimic sales proceeds and movement costs.

The State should retain its option to take gas and NGL in kind.

Valuation of ANS Gas and NGL

Even the best-conceived royalty valuation formula can go astray over time unless it adapts to new conditions.

ANS oil royalties highlights both the need to maintain flexibility in the procedures and mechanisms used to value and pay gas and NGL royalties

Information as to actual dispositions will be vital both to producers and to the State in understanding how ANS gas and NGL value can be maximized

January 2002

Alaska Gas and NGL
Economic Analysis of Value and Royalty

report prepared for the
Alaska Department of Natural Resources
Oil and Gas Division

by Roger Ridlehoover and Barry Pulliam

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Purpose and Plan of this Report

It has been known for years that large reserves of natural gas lie under the North Slope of Alaska, but that its location thousands of miles from large gas consuming markets would require relatively high sales prices in those markets to justify development and transportation investments. In the late 1970s gas prices were high and plans for transportation facilities to move ANS gas to Lower 48 markets were pushed almost to construction when price reversals put the project on hold, where it remained until 2000. Since then, a dramatic gas price spike lasting well into 2001 and ongoing concerns that production from Lower 48 reserves cannot serve expected consumption growth in the decades ahead, have returned ANS gas development and transportation facilities to center stage.

The Alaska Department of Natural Resources (DNR) is charged with developing and managing the State's resources for the maximum benefit of all Alaskans. Oil and gas resources fall under the purview of the Department's Division of Oil and Gas. Production from State lands contributes 80 percent of the State's general fund revenues in taxes and royalties. Oil and gas royalties paid to the Department represent over half of the total revenues. Future oil and gas exploration and development will be essential to State government and the growth of the State's economy as revenues from existing oil production decline.

Alaska DNR commissioned this study of the State's gas reserves to address a number of economic issues arising from anticipated production and sale of ANS gas and NGL. In overview, these issues include:

1. How are gas and NGL markets in North America structured today and how do they operate? What principal factors drive prices in those markets?
2. Over its expected production life, what role will ANS production play in North American gas and NGL markets?
3. What market factors are most important to determination of the value of ANS gas and NGL at the point of production?
4. What market and economic factors are most important to determination of gas and NGL royalty values under the State's lease agreements with ANS gas producers?

Chapter Overview

Chapter 1 is a description of natural gas markets in North America as they are structured and operate today. This Chapter also provides historical background as to the evolution of those markets and discusses how gas markets are likely to operate in the decades to come, over the life of ANS gas production.

Chapter 2 presents a similar overview and description for NGL markets in North America.

Chapter 3 discusses economic and market factors that are likely to determine the wellhead value of ANS gas and NGL production when it begins to flow.

Chapter 4 provides a discussion of basic economic aspects of royalty relationships, including description and analysis of typical provisions for valuing natural gas in royalty agreements.

Chapter 5 reviews the State's lease provisions for oil and gas and how those have evolved and operated for oil production.

Chapter 6 presents conclusions and recommendations as to ANS value and royalty issues facing the State and ANS producers.

Report Summary

- Deregulation of U.S. gas markets over the past 20 years has made them highly flexible and responsive to short-run changes in demand or supply conditions, but less effective at long term planning for coordinated development of large new supply and infrastructure projects. As a result, gas prices are sometimes quite volatile. Transportation bottlenecks and surpluses can appear and persist at different points on the continental pipeline grid.
- In the decades to come, gas markets will continue patterns established over the last several years – short, sometimes dramatic price swings in response to temporary conditions, and growth of supply and infrastructure, sometimes in large increments that can alter existing price and flow patterns for months or years before being fully "digested" into the larger grid.
- NGL markets are less flexible and responsive than gas markets. There are but a handful of NGL finished product trading centers, where transaction prices are set and reported. Prices paid for raw-mix NGL at the point of production typically are set by deducting transportation and fractionation costs from these downstream market centers. Information as to market rates paid for these services is not well developed or circulated. There is no basis today for expecting significant changes in the structure or operation of NGL markets in years to come.
- ANS gas and NGL are likely to enter North American markets via Alberta, a gas and NGL center that to date has experienced wide price swings relative to other market areas. While introduction of ANS gas and NGL into Alberta markets may stabilize them, that result depends on the evolution of production growth within Alberta and pipeline projects downstream of Alberta.
- Delivery of ANS gas and NGL in the same pipeline will cost less than transporting them separately. Such a pipe, though long and large, will be economically similar to a field gathering system from the perspective of owners and users. There is not likely to be a flourishing secondary market for capacity, for example, on the ANS pipeline.
- Alaska's oil royalty experience provides a useful template for gas and NGL royalty. Like ANS crude oil, gas and NGL will be moved to destination markets far downstream. The wellhead value of ANS gas will be dependent upon market prices in Alberta and/or other major "nodes" on the North American gas grid and transport costs to those markets.

- Royalty is an economic partnership with sharing of product or sharing of revenues. It is critical that partners share information.
- During its initial years of production, while ANS gas is being introduced into North American markets, ANS producers should share with the State information at their disposal concerning movement and sale of ANS gas and NGL. This will permit the State and producers jointly to understand how ANS gas is fitting into those markets.
- Following this period of intensive information sharing and analysis, the State and producers will be positioned to evaluate lower-cost alternative valuation methods that accurately mimic sales proceeds and movement costs, such as use of published prices in downstream market centers.
- The State should retain its option to take gas and NGL in kind. Doing so preserves its ability to discipline a royalty partner or to avoid neglect or malfeasance.

Note: Throughout this report we use the term "market" in its most general sense, sometimes referring to a geographic area, and sometimes to trading of a particular product, or most generally to commercial activity surrounding a group of related products or services. Economists sometimes use more precise definitions of "market" when analyzing competitive impacts of firm conduct, or price fixing allegations, for example. Because that was not a purpose of this Report, we use the term in its more casual dress.

Chapter I

Gas Markets in North America

Gas markets in North America, defined here as the United States and Canada, are today in the latter stages of an economic and regulatory transition that began more than 20 years ago. That transition, largely but not entirely completed, is from a highly integrated and regulated industry, to one composed of distinct but interlocking segments, some competitive, some oligopolistic, and a few remaining stubbornly subject to monopoly structure and (if left unregulated) exercise of market power. The transition has been slow because legislatures and regulatory bodies are deliberative, and because the physical and contractual infrastructure created under a commercial and regulatory regime that dated back to the early years of the 20th century involved long-term contractual and regulatory commitments that have taken time to revise, play out, or terminate involuntarily.

Over the past decade, gas markets have shown that complete deregulation of gas sales prices and substantial deregulation of gas transportation rates, has been a success if judged by the market's ability to provide reliable service. Markets have responded well to stresses brought about by periods of extreme cold with its attendant heavy gas consumption, and facility outages caused by hurricanes and explosions. No end-users that wanted supply have been without gas. Deregulation has produced not only a market environment in which prices direct supplies to highest valued uses, but major developments in storage, transportation and risk management techniques have given gas producers and consumers alike tools that they never had in regulated markets. Today gas is a favored fuel because of its clean-burning attributes, particularly among electricity generators, and growth in consumption is expected to continue in the years and decades to come.

That situation is a far cry from the outages and curtailments that plagued U.S. markets as recently as the late 1970s. Then it was feared that North America was "running out" of gas supplies. Alaska gas at that time was primed for development but was not in the event called upon. It serves as useful background in understanding the structure and operation of today's gas markets, and as a guide in thinking about current ANS gas and NGL development plans, to trace the major developments in regulation and commercial organization that gas markets have undergone over the past 25 years.

Historical Overview of Gas Deregulation and Market Development

Passage of the Natural Gas Policy Act (NGPA) in 1978 marked the birth of today's gas industry. It mandated time-phased elimination of wellhead gas price controls, setting into motion a regulatory and industry dynamic toward more open, competitive, segmented gas markets that operate today. A fundamental premise of the NGPA was that lifting price ceilings – and ultimately removing them – would bring forth gas supplies that were sorely needed to satisfy growing consumption, and that competition among gas producers could be relied upon to "regulate" wellhead prices thereafter.

In 1985 the Federal Energy Regulatory Commission (FERC) built on this theme, first with Order 436, requiring that U.S. interstate pipelines provide "open access" to their pipeline systems. Before then, pipelines were largely independent systems with relatively few interconnections, performing all transportation and merchant functions for sales customers – finding, purchasing, and maintaining a gas supply, transporting it, storing it to cover peak demands, and delivering it in accordance with sales contracts and regulations.

With open access, others could buy, move and resell gas supplies using pipeline companies' facilities and, with further regulatory changes, could do so across two or more systems. Though directed to rules affecting pipeline usage and rates, the purpose of Order 436 was to enhance competition in gas commodity markets. The idea was that such markets needed to be more robust both for gas producers and for end-users, with producers able to sell to any potential gas buyer and conversely for gas buyers to be able to reach any potential gas supplier – even those not directly connected to the delivering pipeline. It was reasoned that effective access to all pipelines within the national grid could achieve that objective.

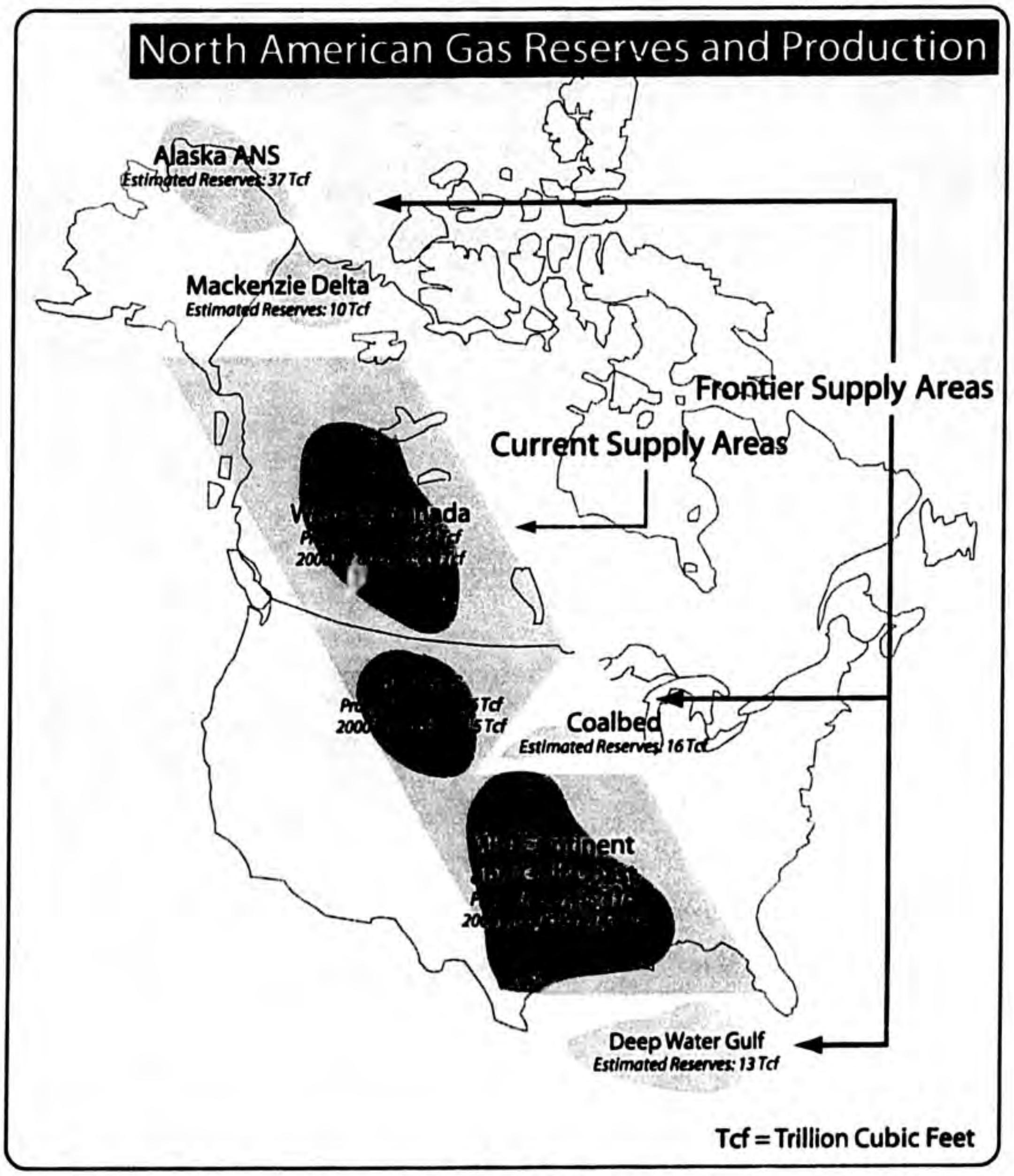
The aims of Order 436 initially proved illusive because pipeline companies retained contractual commitments to suppliers and regulatory obligations to "stand ready" to serve traditional utility customers should independent (non-pipeline) suppliers fail. That put a strain on pipelines and transport customers within the context of shared use of a pipeline facility. So, in 1992, FERC Order 636 relieved that pressure by removing pipeline companies from all merchant functions. Pipeline systems then could be used by all shippers on equal terms, clearing the way for growth of supply, sales, and service markets operating along a transportation grid whose use was neutral with respect to competition in those merchant markets. Order 636 achieved what 436 had attempted – it prompted growth of independent marketing companies and the related industry segments that support gas transactions along the pipeline grid. Gas buyers and sellers could transact with each other irrespective of where either was located.

This regulatory separation, or unbundling, of gas merchant activities from gas transportation service, has brought into clearer focus a distinction in the gas industry between markets for exploration, production, and consumption of the gas commodity itself, and those for the related trading, transportation, financial, and logistical activities that occur between points of production and points of consumption. Transportation and related activities such as gathering, processing and storage have been the subject of regulatory attention in the past decade, and to a large extent the commercial, legal, and regulatory mechanisms and institutions that FERC and state regulators have put in place are stable and can be expected to remain so in years to come, with fine tuning and adjustment as experience and new factors dictate. That part of the industry appears to be settling down after 20 years of perpetual upheaval and change. The focus now is turning from trading and transportation issues toward the serious question of how to find and develop sufficient gas supplies to satisfy growing demand. ANS gas plays a central role in that new focus.

Gas Commodity Markets

Gas reserves in North America lie principally along an axis extending from Alaska and western Canada, through the U.S. Rockies, Texas, and into the Gulf of Mexico (see Figure 1).

Figure 1



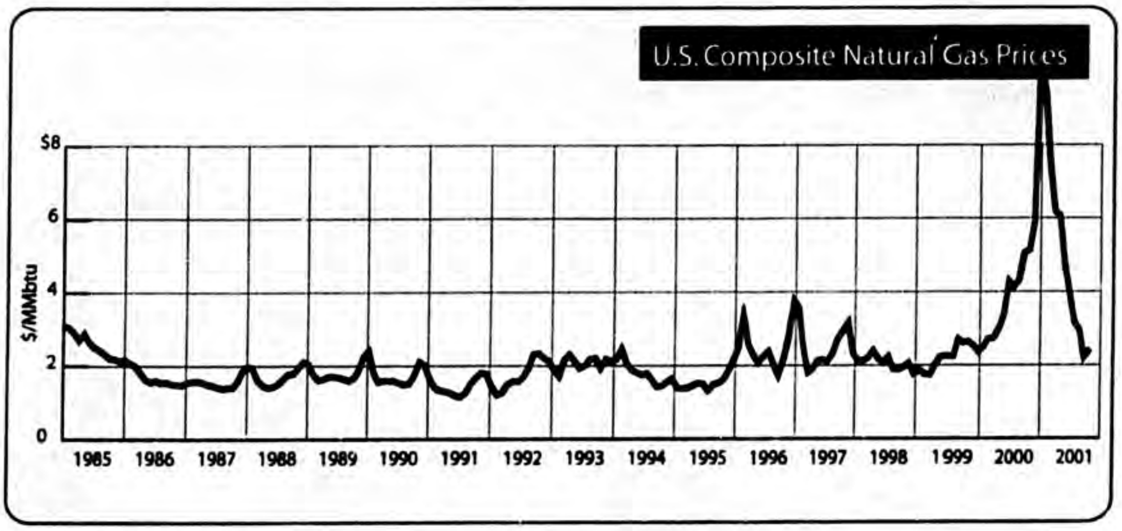
Sources: Potential Supply of Natural Gas in the United States, Potential Gas Committee, 2000.
Natural Gas Potential in Canada, 2001, Canadian Gas Potential Committee.
Natural Gas Monthly, March, 2001, U.S. Energy Information Administration.

More than two-thirds of North American gas is produced along this axis. Historically, gas produced in these areas was purchased by an "anchor" pipeline under a long-term agreement. Pipelines were approved and built if they could demonstrate control, through ownership or contract, of sufficient reserves to serve for many years the requirements of downstream customers that the line proposed to serve. When approved by federal and state regulators, the anchor pipelines took the contracted supplies to consuming markets in the Upper Midwest, Northeast, and West. Gas prices typically were set at regulated levels, with periodic escalations as permitted by regulations. Producers had little marketing responsibility after the long-term agreement was in place.

In the late 1970s, shortages of gas developed in many parts of the United States. Blame was placed at the feet of price ceilings that were too low to elicit exploration and production of new reserves or to give consumers incentive to conserve. In 1978, removal of price controls resulted in increases that had the intended effect on both producers and consumers. Drilling and exploration activity jumped sharply throughout North America. In 1975, 1,800 drilling rigs were operating in North America; by 1981, over 4,200 rigs were in operation, and with predictable results – more gas was found and offered to market. In fact more was offered than consumers would (at the higher prices) accommodate. Gas prices fell sharply in the mid-1980s and stayed low for over a decade as the gas supply "bubble," built up in the early 1980s, stayed stubbornly inflated.

Deregulated sales prices explain only part of the story of gas market development in the 1980s and 1990s. With the advent of open access transportation (1985) and removal of pipeline companies from merchant functions (1992), producer gas sales moved downstream from the wellhead to points of delivery at nearby transmission lines, or even further downstream to points of interconnection among several pipelines and, as confidence grew that trading opportunities would be available when and where they were needed, sales agreements became shorter. The spot market, born in the mid-1980s, provided short-term prices that broadly signaled market conditions both to producers and to consumers.

Figure 2



Source: Natural Gas Week.

In the 1990s, periodic episodes of cold weather, hurricanes, and other short-lived factors generated a few price "spikes," but in general North American consumers enjoyed low gas prices throughout the decade. That prompted steady growth in gas consumption, aided by its reputation as a clean fuel for industrial uses and for electricity generation. But low prices provided weak incentives for producers to find new reserves and at times in the 1990s, they began withdrawing resources not only from ongoing exploration but also from development of existing fields. By April 1999 the North American rig count had fallen to 558.

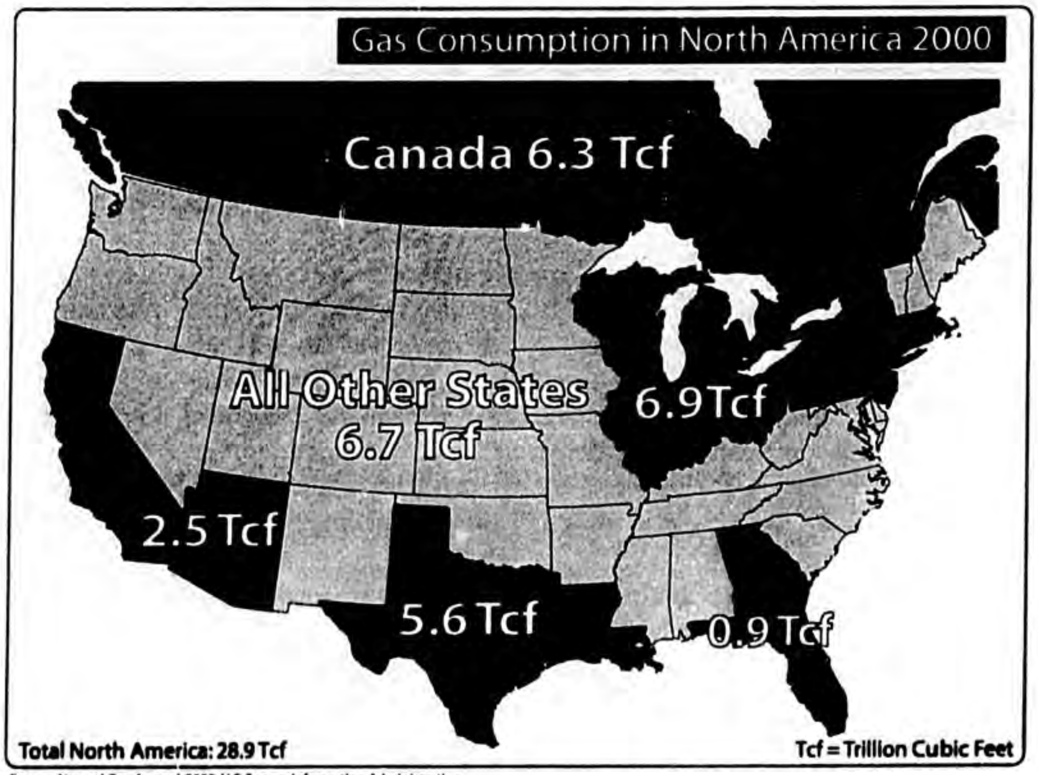
In Spring 2000, the "quiet" market conditions of the 1990s were abruptly awakened as prices began a steady climb early in the year. A confluence of temporary factors (a pipeline explosion, low storage levels), and longer run trends (continuing appetite for gas by electric generators), created a sudden and unanticipated price run-up (see Figure 2). To most, the increase appeared to be more than just another temporary price spike. Throughout 2000 and into early 2001, conventional wisdom became focused on the idea that a new, permanently higher price level had been reached and would be maintained. Yet, from the vantage point of early 2002, both gas production and consumption have again shown themselves to be more responsive to price than conventional wisdom expected. Drilling and exploration activity quickened in 2000 and new supplies began to reach markets in 2001. Higher delivered prices to consumers also caused many to cut back consumption. Plans for new electric generating plants were delayed or canceled. Today, gas prices have returned to levels seen throughout most of the 1990s.

The lesson offered by this history of gas commodity markets and prices is that both production and consumption respond to price changes. As described further below, today they do so quite rapidly, both from the perspective of fluctuations in supply or demand conditions caused by temporary factors such as weather or facility problems, and from the longer-term perspective of continuing development of new supplies to replace depleted wells and provide for growing markets.

Gas Trading, Transportation and Logistics

While gas production in North America is concentrated along a north-south axis centered on Wyoming, apart from Texas and Louisiana, large gas consumption areas lie on an east-west axis from the upper Midwest and Northeastern states to the West and California (see Figure 3). Consequently, a primary task facing the gas industry is getting gas from producing areas to consumers.

Figure 3



Source: Natural Gas Annual 2000, U.S. Energy Information Administration

As noted above, pipeline companies used to perform that function, under the direction of federal and state regulators. They purchased gas at the wellhead, then gathered, treated, processed, compressed, stored, transported, and delivered it to customers. But pipeline companies today provide only transportation service; all other merchant activities are performed by independent companies, or by pipeline affiliates subject to a regulatory mandate of open and non-discriminatory service.

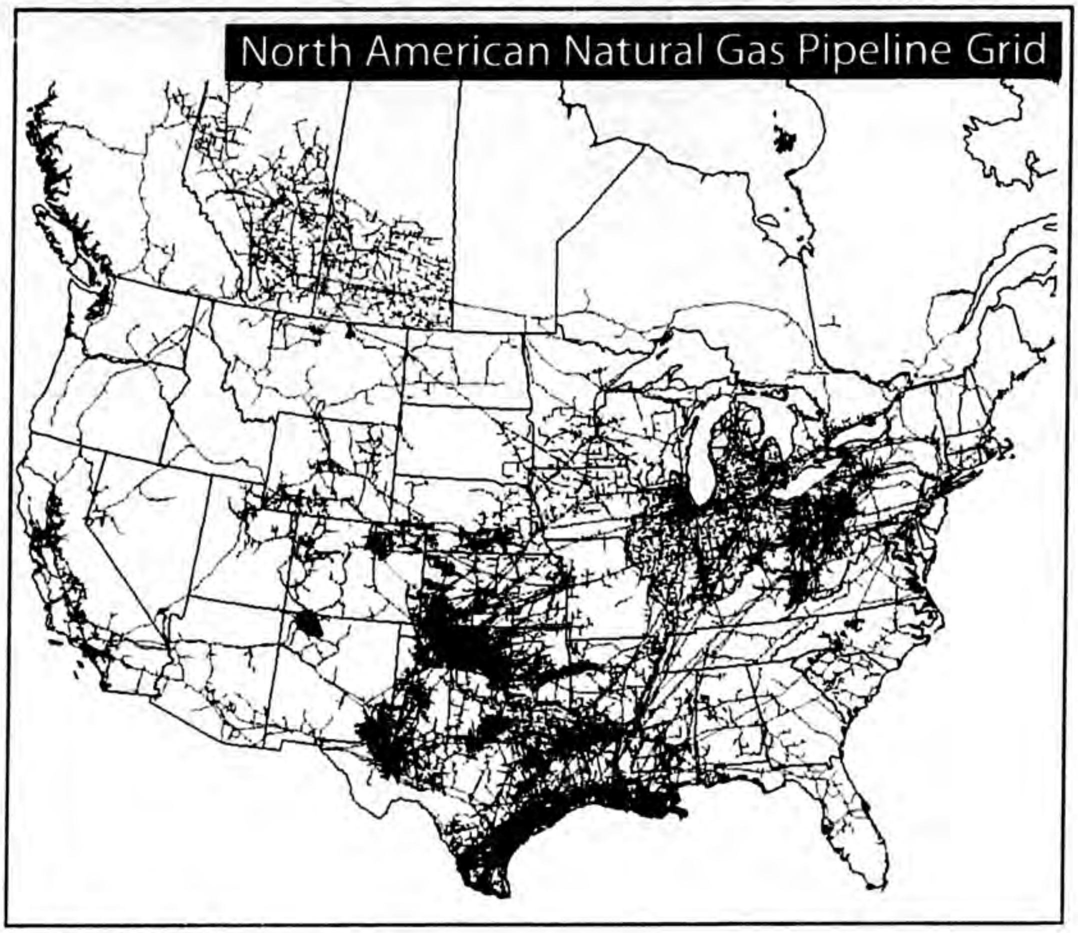
The transition from integrated, bundled pipeline service to today's segmented market has seen the emergence of distinct market segments that provide a host of services along the pipeline grid. These segments operate alongside and in conjunction with gas commodity markets, and include: 1) gathering and processing; 2) pipeline transportation; 3) marketing and trading; 4) market centers or "hubs;" 5) storage; and 6) gas-related financial instruments. Each plays an important role in how the industry operates today, and exerts influence on upstream prices realized by producers and on end-use prices paid by consumers.

Gathering and Processing. Gathering systems are small-diameter pipeline networks of limited geographic scope that act as a bridge from wellheads to the continental pipeline grid. Typically, gathering firms not only move gas from wellhead to grid but also provide services such as compression, dehydration, and gas conditioning to remove impurities and water. Most prominently, though, they also extract natural gas liquids (NGLs) that can be present in the gas stream (see Chapter 2). Traditionally performed by pipeline companies as part of their regulated, bundled service, or by producers as part of the sale of gas production, gathering and processing now are provided also by independent companies under unregulated rates and terms. As greater specialization has taken hold in gathering and NGL processing, agreements have evolved from long-term contracts covering large tracts of developed and undeveloped lands, into shorter, more flexible, and often more geographically compact arrangements. In addition to new commercial forms, competition among gatherers has generated a number of new services, including low-pressure gathering, condensate measurement and marketing, water disposal, and remote flow measurement.

Development of a distinct gathering and processing industry has freed production companies to focus efforts on finding gas, eliminating diversion of resources and management to operations that bear little relationship to knowledge and expertise required for their exploration business.

Long-distance Transportation. Once gathered, treated, compressed and processed, gas is delivered into a transmission pipeline that in turn is part of a continental grid of interconnected pipelines (see Figure 4). That grid is a displacement network, meaning that when gas is injected into the system it is commingled with other supplies that have entered upstream. Buyers withdrawing supplies are not concerned to know the specific (physical) source of the gas because uniform quality standards imposed by all pipelines assure that gas within the grid is fungible. As a result, gas bought by customer B from supplier A may not actually move from A to B; rather, the volume put into the system by A matches the volume removed by B.

Figure 4



Source: Penwell MAPSearch.
http://www.mapsearch.com/pipelineFacility.cfm

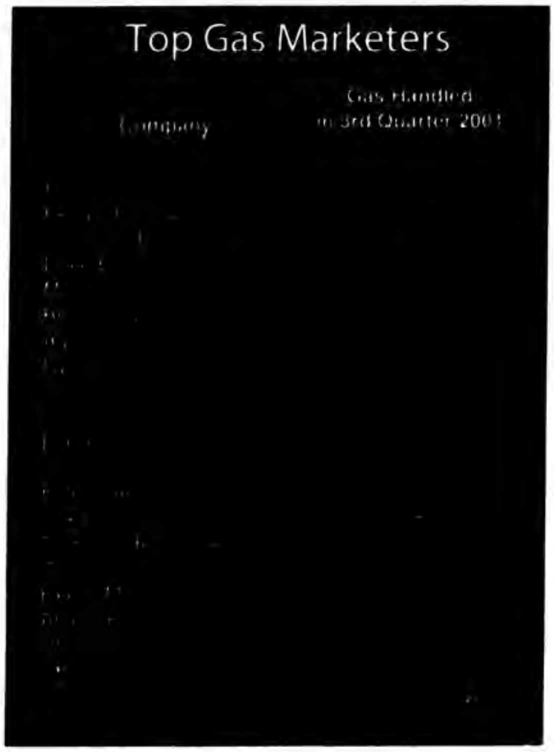
The fungibility of gas once it enters the pipeline grid creates opportunity for substantial transportation cost savings compared to a system where specific bundles of product are matched and traced from supplier to customer. FERC Orders 436 and 636 (and most recently, Order 637) were specifically designed to achieve that efficiency by standardizing operating protocols and facilitating contracting across interconnected systems. Gas marketers, producers, and end users can create customized pipeline systems within the existing physical (and separately owned) pipeline systems to "move" gas from hundreds of independent supply sources to a like number of customers. Fungible supplies also greatly facilitate creation and trading of financial instruments tied to gas.

Much of FERC's ongoing work with respect to natural gas relates to removing remaining impediments to efficient use of the pipeline grid. In crafting rules designed to do that, FERC is mindful of the dilemma it faces concerning short-run efficiency versus long-run efficiency. In its official pronouncements, and in speeches given by commissioners, it appears that FERC is striving to attain both; that is, it is trying to create a pipeline market where short-run price signals effectively ration available capacity <u>and</u> provide appropriate long-run incentives for investments in new systems and expansion of existing ones.

Marketing and Trading. If there is one party that straddles all aspects of the gas industry, it is the gas marketing company. These firms obtain access through ownership and/or contract to facilities needed to: a) assemble a portfolio of gas supplies; b) hold and repackage them as necessary; and c) make deliveries to a portfolio of gas customers. Competition among marketers (entry into the industry is relatively easy), coupled with opportunity to earn unregulated profits has created intense pressure on them to create innovative services and to minimize costs. That competition confers a tremendous economic benefit both to gas producers and to consumers.

Marketing firms have come to the business from a variety of paths. Some were created out of pipeline companies, some from producers, and some from gas distribution companies. Marketers handle more than 80 percent of gas consumed in North America.

Figure 5



Gas marketers' activities serve to link gas and other energy product markets, particularly electricity. These linkages have had a number of impacts on operation and development of the gas business:

- Cross-commodity risk management
- Short-term gas purchase agreements (weekly, daily, even hourly) and associated short-term transportation capacity agreements.
- Short-term storage agreements
- Greater summer demand by electric load that smoothes the gas industries' traditional winter peak
- Siting of new electric generating plants along pipeline routes or near gas market hubs.

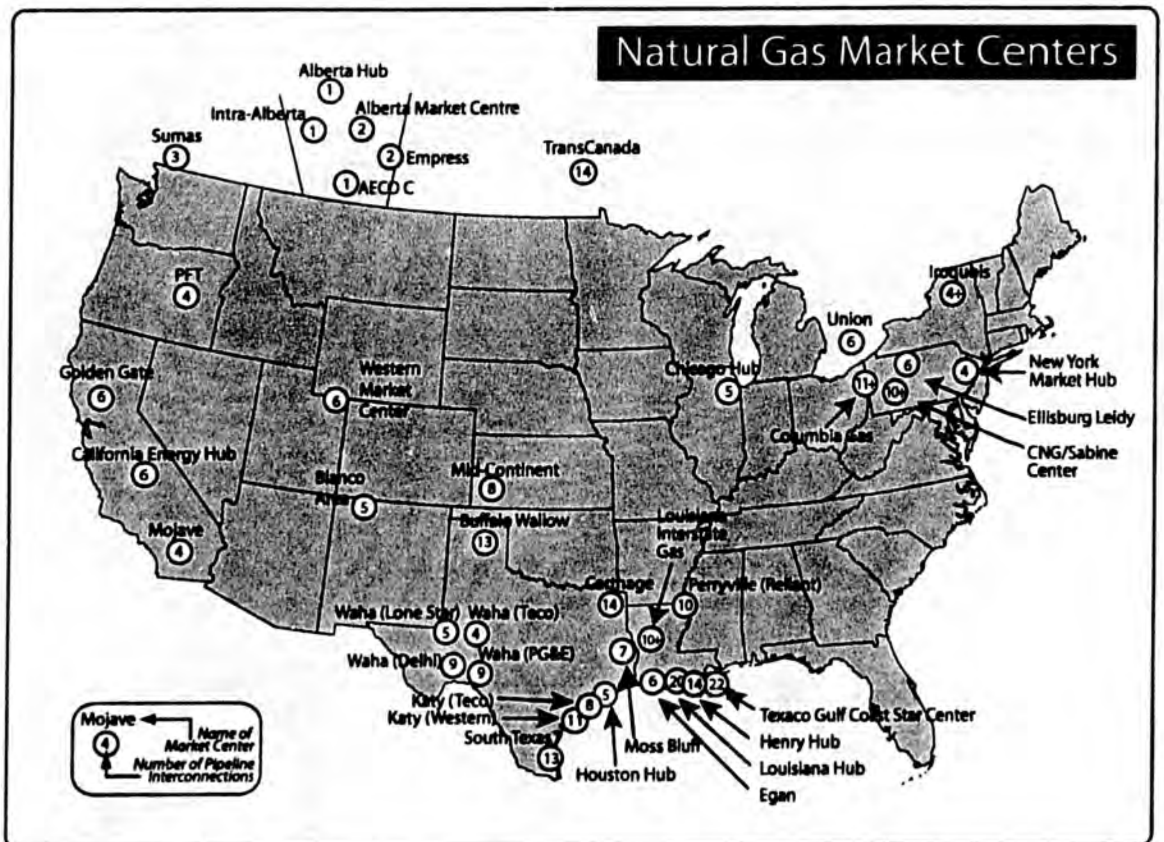
The emergence of marketing firms also has spurred growth and innovation in activities related to marketing. For example, marketers' need for information has created a robust industry of firms that collect, interpret, analyze, and distribute information of relevance and importance to gas buyers and sellers, including information about weather, prices of gas and other fuels, transactions, demand patterns, storage flows and levels, and much more. Government agencies, private firms and quasi-public organizations such as trade associations and industry groups also contribute to regulatory hearings, conferences, trade shows, and other public forums that spread information among market participants.

Some of these organizations are active in making contracting and exchange less costly by writing and endorsing standardized sales, storage, and transportation agreements. The Gas Industry Standards Board (GISB), for example, is a quasi-public organization composed of representatives from several segments of the industry. Though GISB is the focal point for this effort, private companies participate as well when, for example, they create and offer electronic trading services using standardized agreements. Some of these trading platforms simply provide low-cost means for buyers and sellers to effect trades they already have arranged, but others provide a market-making function of internally matching buyers and sellers so that both can transact anonymously and cheaply.

E-commerce in the gas industry, though still relatively new, is advancing quickly. It is expected that all trading of gas, pipeline capacity, and storage will occur at a computer screen rather than by phone and fax (financial instruments already are so traded). That will make the industry even more responsive to short-run changes in market conditions.

Market Centers (pipeline "hubs"). Market centers are places along the pipeline grid where marketers and others aggregate supplies prior to transshipment to downstream customers. There are 38 market centers across North America, with six more in various stages of development. In general, such hubs lie near the intersection of two or more pipelines.

Figure 6



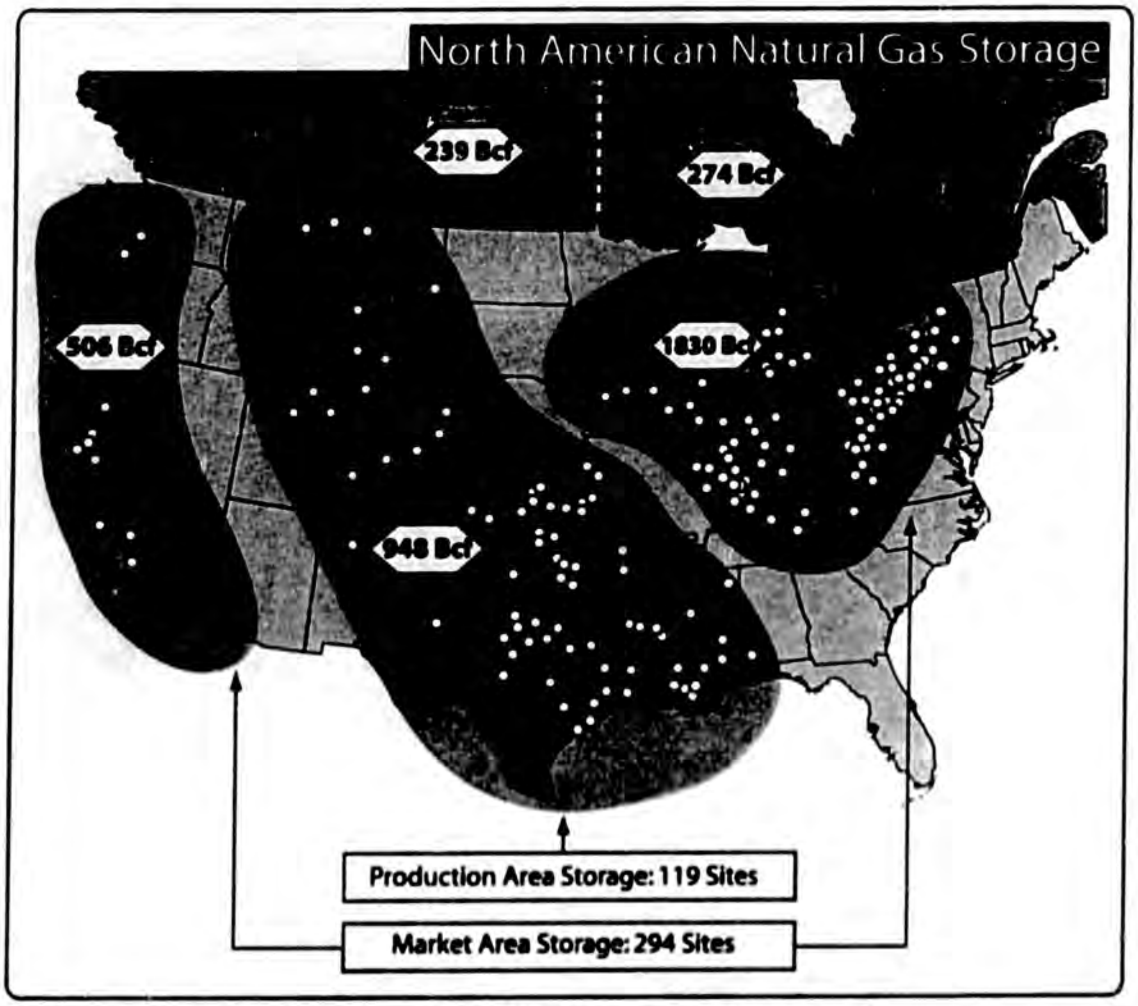
Source: FERC Policy Discussion Paper 99-01 (June 1999).

Hub management involves operation of physical facilities such as pipes, valves, storage, and compression, and provision of ancillary services that are useful to marketers, producers and other customers, such as electronic trading, "wheeling" gas from one pipeline system to another, short-term gas storage ("parking"), short-term lending or borrowing of gas among traders, long-term storage, or other forms of transaction support.

FERC recognized that pivot points along the grid would be an important element in creating responsive gas markets. To that end, it forbade pipelines that connect to hubs from taking any actions that could distort or discourage use of them. The result has been steady and substantial growth both in the number of hubs operating and in the services offered. Today, there are production-area hubs, where upstream supplies congregate awaiting dispatch to distant markets, and market-area hubs, where supplies are "staged," awaiting delivery to nearby end-use customers. Many local distribution companies (large buyers of gas) have come to rely heavily on nearby market-area hubs as a supply source. That relieves their burden of locating supplies and arranging long-distance delivery. That these kinds of customers, who bear a legal obligation not to run out of gas supply, consider market-area hubs to be reliable sources illustrates their importance in today's gas industry.

Storage. Gas storage facilities often are associated with market hubs, though many exist apart from them. There are three types of storage facilities: aquifers, depleted gas fields, and salt domes. Depleted gas fields and aquifers can provide a large volume of storage capacity, but typically exhibit slow injection and withdrawal speed. Salt domes are smaller, but can take in and release stored gas more quickly. That attribute is especially important for storage facilities near consuming markets, where weather can trigger large pulls on stored gas, or at hubs, where temporary excess supplies can be inserted into storage and removed a short time later.

Figure 7



Source: U.S. Energy Information Administration, Form EIA-191, "Monthly Underground Gas Storage Report."
Canadian Gas Association storage survey - November 30, as reported in Gas Daily, December 10, 2001
American Gas Association storage survey - November 9, as reported in Gas Daily, November 10, 2001

The number and kind of services offered in connection with storage have grown and become more innovative. Storage once was a tool used only by local distribution companies to provide peak winter deliveries, but now it is used by producers, marketers, large end users, and local distribution companies, for a variety of reasons, including daily balancing, risk management, and trading.

Financial Instruments. In addition to creating geographically diverse portfolios of supplies and customers, marketers and others also hold supply and delivery positions that span time. To aid management of price risk inherent in such inter-temporal obligations, these parties have turned to financial markets for risk-hedging and trading instruments. The natural gas futures contract created by NYMEX in 1990 became the fastest growing contract, in terms of volume traded, in that exchange's history. Futures contracts, forward contracts, options, swaps, and other financial instruments related to gas, NGL, and allied products are traded on organized public exchanges, and via private exchanges such as Intercontinental Exchange (ICE) and those operated by large marketers such as Dynegy. A principal use of these financial instruments is risk management. Marketers, producers, and customers can, at low cost, "lock in" prices using them. The ability to do so aids financial planning, reduces capital cost, and permits more efficient use of physical assets.

The new features of gas logistics that have grown up over the past 10 years – marketing companies, open access transport, hubs, storage, and financial instruments – all serve to make gas markets highly responsive to short-run changes in supply or demand conditions. Gas sales, transportation, and storage agreements today are shorter than those in the integrated, regulated industry because most buyers and sellers have confidence that trading partners will be available when and where they are needed. Transportation rates, storage rates, and even gathering and processing rates all can change relatively quickly. As a result, gas prices at a specific market location can be quite volatile, as can price differences between locations. While that serves to discipline markets and efficiently allocate existing supplies and facilities to their highest valued uses, it can weaken or distort long-term price signals for investments.

The enhanced short-run efficiency of the gas industry is therefore a mixed advance to the integrated, regulated industry of years past. With today's disaggregated industry, short-run prices are responsive, but long-range planning is harder. In the past, the process of regulatory approval for pipeline projects imposed an organizing mechanism that effectively coordinated simultaneous development of pipelines and supplies. That mechanism no longer operates, and today pipelines and supplies can be built and developed on different schedules, sometimes leaving one without the (properly-sized) support of the other. Examples abound. Development of U.S. Rockies gas over the past decade or more provides numerous instances of excess pipeline capacity (when a new project is completed), followed by excess gas supplies (as new fields are found or developed). The San Juan Basin and Gulf of Mexico are other examples.

The economic effect of independent development of supply and infrastructure is that the continental grid works less efficiently than it otherwise might, with some sections suffering over-capacity (and low transport rates) while others are full (and enjoy high transport rates).

North American Gas Markets over the Next Several Decades

Over the past two decades, the regulatory focus has been on facilitating development of gas commodity markets by, ironically, reforming pipeline rates and access rules. The success of that program has changed dramatically the way gas is bought and sold, and how pipelines and storage facilities are utilized. Now market institutions such as electronic trading, futures contracts, risk management techniques, hubs, storage, and others are firmly established and can be expected to remain in place. Economic forces now shaping the industry include a rate of demand growth that threatens to outpace development of new gas reserves; fine tuning of pipeline regulation by FERC; adoption of standardized trading instruments and electronic trading methods; and continuing expansions and extensions of the pipeline network and related facilities such as storage and hubs.

Over the next several decades, the marketing and logistic aspects of the gas industry will continue to undergo refinement and adjustment, but the industry's main focus will likely return to the serious problem of finding enough gas reserves to satisfy growing consumption, especially that associated with electricity generation, and integrating them into new and existing physical systems and market trading patterns. Management of that two-fold process of supply and infrastructure development is likely to remain fractured and accordingly, the industry will continue to find at any point in time that its transport grid has sections with excess capacity, and others that are severely constrained.

Consensus projections call for North American gas consumption to exceed 35 Tcf by 2020. Figure 1 above shows that in order to satisfy that demand over the next several decades, the existing gas production axis will need to be extended at both its northern and southern ends. ANS gas will be a key component. How ANS gas will fit into the Northern American market, and how it is likely to be valued there are discussed in Chapter 3.

Chapter 2

NGL Markets in North America

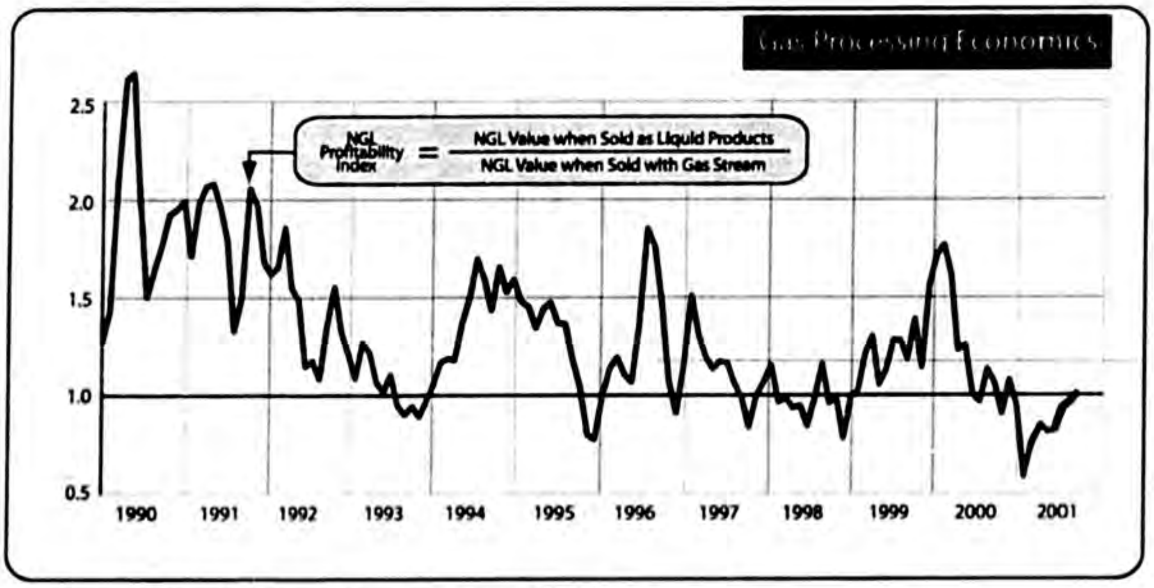
Natural gas liquids (NGL) are by-products of natural gas, carried to the surface by the gas stream itself. The hydrocarbon liquid produced with natural gas is a mixture of ethane, propane, butane, pentane, and more complex hydrocarbon molecules. It can be, and in some producing areas, must be, extracted from the gas stream and sold as a separate product. NGL markets, though linked to natural gas, are different in organization and operation.

Extracting finished NGL products from a gas stream is a two-step process. The first – called gas processing – typically occurs at a plant located near gas wells, where a "raw mix" of liquids is removed from the gas stream. That liquid mix then is piped or trucked to one of several fractionation centers in North America, where – step two – finished products ethane, propane, butane, and others are separated and sold.

Whether NGL extraction adds value to a particular gas stream depends on how much NGL is present and on the prevailing relationship between NGL prices and natural gas prices. Extraction adds value when revenue from NGL sales exceeds extraction, fractionation and transport costs <u>and</u> the opportunity cost of leaving the NGL in the gas stream and selling them along with the gas (methane). That opportunity cost arises because gas with liquids contains more heat than gas without liquids and therefore is more valuable.

These factors – gas prices, NGL prices, and costs – fluctuate on a daily basis, and often quite dramatically, so the profitability of gas processing is uncertain and difficult for any gas producer to predict.

Figure 8



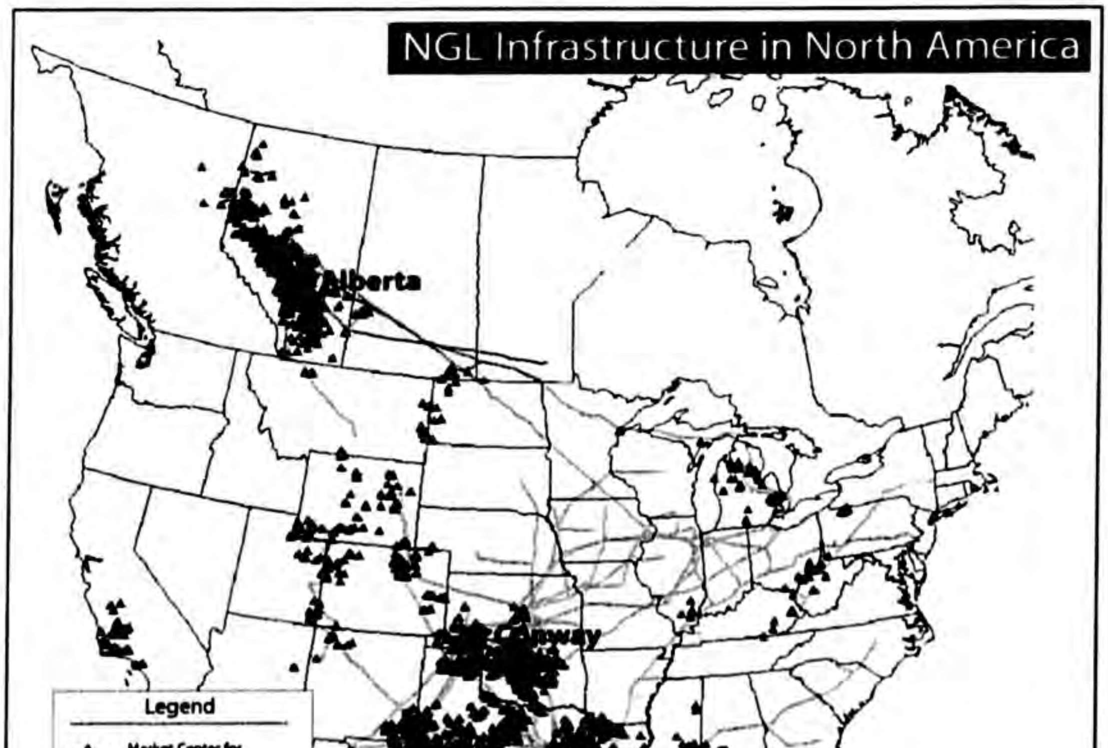
Notes: (1) NGL Value When Sold as Liquid Product = Mont Belvieu Composite NGL Price times two, a typical number of NGL Gallons in an Mcf of gas.
(2) NGL Value When Sold With Gas Stream = Henry Hub Price times 25%, a typical heat loss associated with NGL extraction from gas.

Source: Mont Belvieu Composite NGL Price: Gas Processors Report.
Henry Hub, Louisiana: Natural Gas Week.

Figure 8 shows a measure of the profitability of NGL extraction. The index shown is simply the ratio of the dollar value of gas when its NGL is extracted and sold separately, compared to the dollar value of that same gas if sold without removing NGL. When the ratio is greater than 1.0, NGL processing can be favorable to a gas producer (depending on plant costs); when the ratio is less than 1.0, NGL processing is not profitable. On average, the upgrade associated with NGL extraction (using the assumptions of Figure 8) is eight percent. That is, the value of NGLs extracted over the period shown was eight percent higher than the value of gas lost in the extraction process. That implies an added value from processing of 12 cents per mcf (thousand cubic feet) before payments to processing plant owners. As the Figure indicates, while gas processing is most often profitable, it is sometimes unprofitable and the economics are volatile.

Against the background of this uncertainty, the NGL industry also must cope with the problem that many of the facilities needed for processing – extraction plants, storage, pipelines, and fractionation facilities – entail large, sunk investments. Accordingly, it is not feasible to move resources quickly into or out of gas processing in response to short-term fluctuations in prices or profits. These two facts – fluctuating and uncertain profitability, and sunk capital – drive much of the operation, contracting, pricing and economic organization of NGL markets.

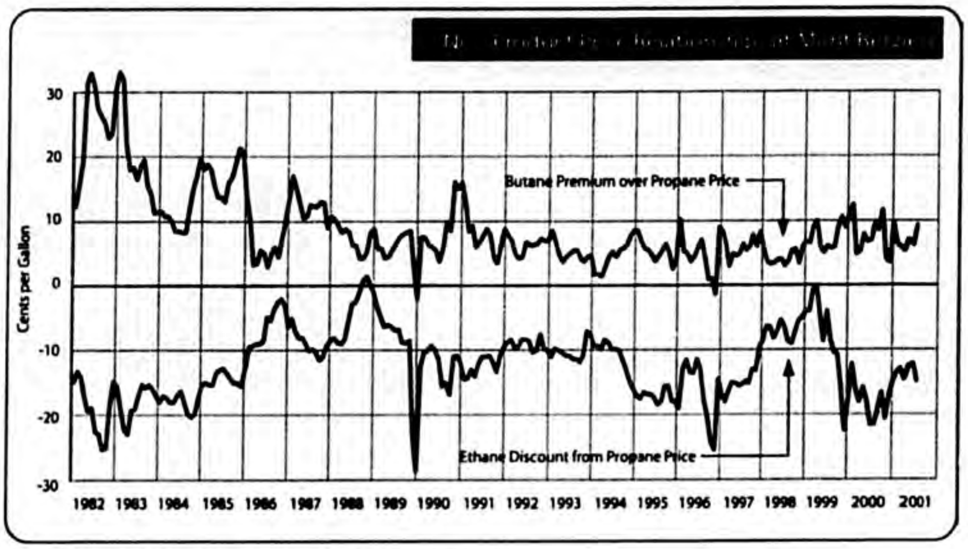
Figure 9



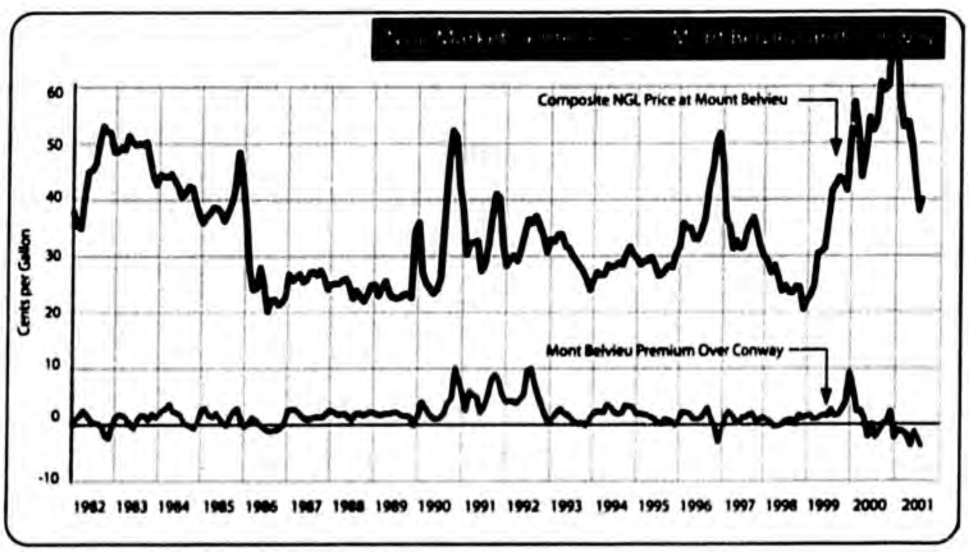
Source: Penwell MAPSearch.
http://www.mapsearch.com/pipelineFacility.cfm

Figure 9 shows the geographic distribution of NGL processing plants, pipelines and fractionation centers in North America. Fractionation centers generally are located near petrochemical plants (major customers of NGL finished products). Mont Belvieu, Texas; Conway, Kansas; and Alberta, Canada are three of the largest such centers. These also are where sales markets for NGL finished products are most active and, therefore, where arms-length transaction prices are established and widely quoted through publications and information services. The price of each finished product is subject to distinct market forces. While these prices move in sympathy, they do not always move in lockstep. The same finished product sold at different market centers can trade at substantially different prices. This web of product and price dynamics adds considerable complexity to NGL markets that is not present in gas markets. Examples of these price patterns and relationships are illustrated below in Figure 10.

Figure 10



Source: Ethane: 1982: Butane – Propane News; 1983-2001: Gas Processor's Report.
Others: 1982: Platt's Oilgram Price Report; 1983-2001: Gas Processor's Report.



Source: Ethane: 1982: Butane – Propane News; 1983-2001: Gas Processor's Report.
Others: 1982: Platt's Oilgram Price Report; 1983-2001: Gas Processor's Report.

Processing Agreements

Producers of NGL-bearing gas usually enter into a contractual agreement with a nearby processing plant to remove raw-mix NGL. These agreements allocate the costs, benefits, and risks of processing.

1. *Keep-Whole Agreements.* Here the gas producer allows the processing plant owner to extract and sell NGL present in the gas. In return, the producer receives a quantity of MMbtu's, in the form of gas, equivalent to the heat content of the extracted liquids. Thus, the gas producer is "kept whole" for the loss of heat that results from removal of NGL from his gas stream.

2. *Percent of Proceeds Agreements.* Under this arrangement, the gas producer and processing company split proceeds of NGL sales, with the producer usually retaining 70 percent or more. Normally, the producer bears the cost of fuel consumed in operating the processing plant, and the cost of heat "shrinkage" associated with removal of NGL-related MMbtu's from the raw gas stream.

3. *Fee for Service Agreement.* Under this arrangement the gas producer simply pays a fee to the processing company for its service, bears all the opportunity cost associated with plant fuel and shrink, and sells for its own account all the NGL that is extracted.

Variations within each type affect the cost-, benefit-, and risk-sharing characteristics of each, but in general keep-whole arrangements allocate cost, risk, and reward to the processing company; fee-for-service arrangements allocate cost, risk and reward to the gas producer; and percent-of-proceeds arrangements allocate some cost, some risk, and some reward to both.

Downstream Finished Product Prices Determine Upstream Raw-Mix Values

Processing plants are located in gas producing areas and most are far removed from fractionation centers and finished-product sales markets (see Figure 9). There are over 1,500 processing plants sprinkled throughout the gas production belt that extends from western Canada to the Gulf of Mexico. By contrast there are 86 fractionation plants, with over half of total fractionation capacity located in the Houston, Texas area, Conway, Kansas, and Alberta, Canada.

Because little or no active market trading occurs at most upstream processing plants, the value of raw mix NGL produced at them depends upon the plant's location relative to one of the large NGL fractionation and finished product sales markets. Upstream NGL prices typically are set equal to published prices for finished products sold at Mont Belvieu, Texas or Conway, Kansas less deductions for transportation of the raw-mix NGL and fractionation costs. That formulation sounds simple, but in practice it can be a complex derivation of value, owing mostly to the difficulty of obtaining information concerning cost deductions.

Gas producers, with operations upstream even of processing plants, can readily obtain published information as to finished product prices at downstream market centers, but often they have little or no information about transportation and fractionation costs incurred to move their raw mix NGL from a nearby plant to those markets. Plant owners, who must bear those costs, have direct access to them. As a consequence of this information asymmetry, intentional or inadvertent distortion of deductions can be used to lower the value paid to producers (or equivalently, to raise processing plant charges). At a minimum, the asymmetry presents an ever-present negotiating tension between producers and plant owners.

This wellhead NGL valuation difficulty is a persistent problem for gas producers and allied claimants (royalty owners, taxing authorities) for a number of reasons:

1. The transportation grid for NGL is not comparable to the gas grid – It is smaller, with fewer interconnections, fewer market centers and, for the most part, it is not a displacement network. See Figure 4 in Chapter 1 and compare it to Figure 9 above.

2. There are far fewer marketers buying and selling NGL than for gas.

3. NGL finished product customers tend to be clustered around the major fractionation and market centers. This leads to active trading at these market centers, but little outside of them.

4. Accumulation and dissemination of information concerning prices and the cost of services such as transportation and fractionation is much less than exists for gas markets.

In short, NGL buyers and sellers work with less public information and fewer trading tools than those in gas markets. There is little or no publicly-available price information, for example, regarding prices paid for NGL at upstream locations away from the major NGL market centers. Upstream NGL values that are derived or estimated solely from public information may only approximate what actual transaction prices might be if upstream market activity was widely reported.

There are other attributes of the NGL industry that distinguish it from natural gas. For example, contracting and exchange in NGL markets is not highly standardized and still involves significant cost of negotiating and monitoring agreements. Agreements tend to be longer than is typical for gas sales. Both input costs and product prices are subject to economic forces in related markets (natural gas, petrochemicals, gasoline refining). And, an imbalance of knowledge and information exists among those in the industry. In short, NGL markets in North America are far less "commoditized" than those for gas.

North American NGL Markets Over the Next Several Decades

Like gas markets, NGL markets are likely to operate in the future much as they do today, but for different reasons. The gas industry has moved a long way toward commoditizing not only gas, but related services such as transportation, storage and financial instruments. This makes those markets accessible to a wide variety of participants. While some NGL finished products may be considered commodities, the ease of market exchange is far less than it is for gas. That is not likely to change in the foreseeable future. NGL markets will remain the domain of specialists. There will continue to be a relatively small number of NGL market centers in North America where prices are determined by trading among a relatively small number of buyers and sellers. That limits the amount of information upon which to base value estimates outside these market centers. And finally, there is no regulatory force at work now to push NGL markets in any discernible new direction. Though every market undergoes change over time, there is no basis today for predicting that NGL markets will change.

Chapter 3

Valuation of ANS Gas and NGL

Current gas consumption in North America is about 70 billion cubic feet (Bcf) per day. Consensus growth projections, if realized, would put consumption at 85-90 Bcf per day by 2010. Current NGL consumption in North America is about 120 million gallons per day. Assuming continued NGL extraction rates, projected NGL production for 2010 would be 154 million gallons per day. A developed and flowing ANS supply of 4 Bcf per day of gas and 10 million gallons per day of NGL would account then for about 5 percent of total North American gas sales and 7 percent of NGL sales.

The value of Alaska gas and NGL when it begins production will depend upon prices and market conditions in North America, not in-state markets. Local markets cannot absorb the large volume of gas produced from ANS fields, even at very low prices. The bulk of ANS gas and NGL will flow to markets in North America and accordingly, analysis of valuation must focus on its anticipated role in those established markets. A few key factors will determine that role: the pace of North American demand growth; the ability of existing producing areas to maintain or increase output; the size, development cost, and accessibility of frontier supply areas other than Alaska; and the specific intermediate and destination markets within North America to which ANS gas and NGL are most likely to be routed.

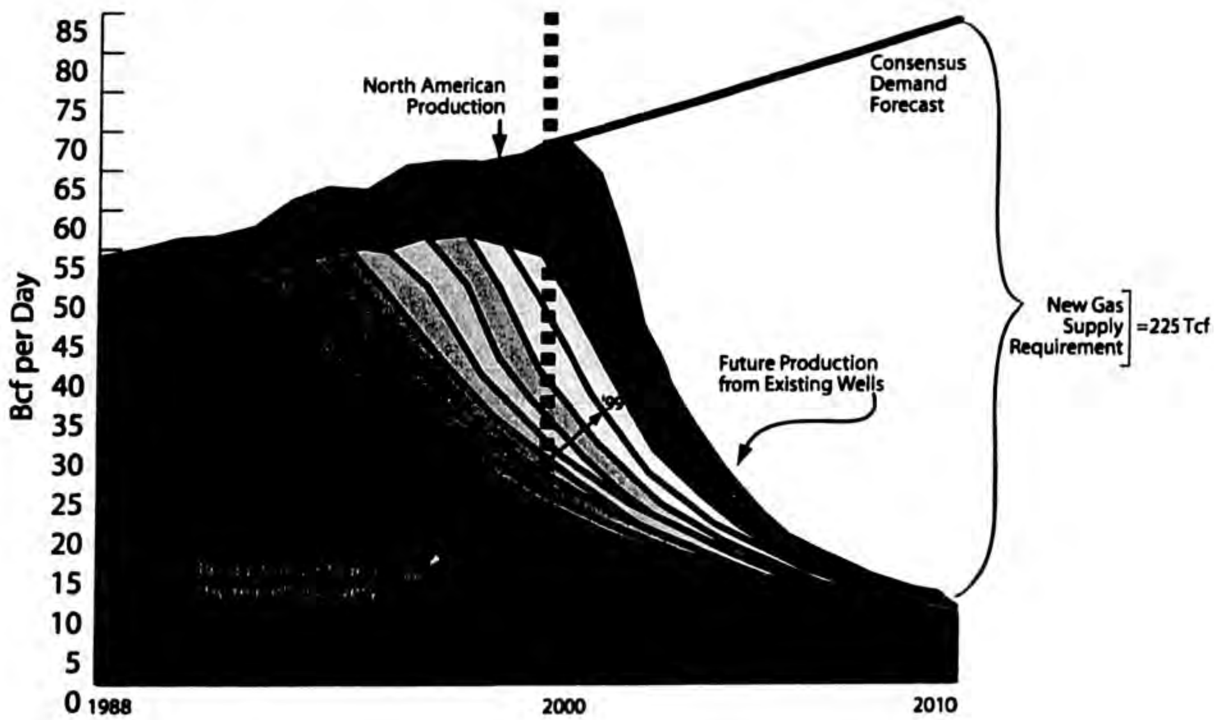
North American Demand Growth

Judging whether consensus projections of North America gas consumption are accurate is, of course, difficult. A skeptic could point to forecasters' inability to predict, even for relatively short periods, prices of gas, electricity or crude oil. Relationships among these are critical inputs to any gas consumption forecast and given our inability to forecast them, no consumption forecast deserves much respect. Yet, short of adopting that agnostic view, there is no better basis for planning and conducting analyses of future markets than to utilize these projections, with due scrutiny of their assumptions.

A number of organizations and government agencies forecast gas consumption, including the Gas Research Institute, the U.S. Energy Information Administration, and the Canadian Energy Research Institute. These and others generally predict that gas consumption will increase 2-3 percent per year over the next two decades. These forecasts are based upon projections of economic growth and continued expansion of gas use in electricity generating plants and other industrial uses. Notwithstanding the recent dramatic price increases of 2000-2001, it is generally accepted that gas will continue to play a dominant and expanding role in North America's energy mix over the years to come. Certainly there are "wild cards" that could alter that picture, such as advances in fuel cell technology, distributed electricity generation (which could increase or decrease gas use depending on the technology developed), and environmental regulations. But none of these has risen yet to a level of commercial importance sufficient to cause forecasters to predict a slowing or reversal of gas consumption growth.

Thus, under almost any expected growth scenario, expansion of gas and NGL consumption in North America will continue. But that expansion cannot occur without development of new supply areas. By its nature, production from existing fields declines over time, or can be maintained only with continuous development of new geologic strata or "step-outs" from already developed acreage. Advancing technology applied to existing supply areas surely will extend the economic life of those fields as it has in years past, but relying on such technology alone is not likely to satisfy growing consumption markets in North America. Figure 11 below illustrates the dual effects of a depleting gas supply and growing consumption – the gap between them grows quite rapidly indeed. That gap must be filled by technology applied to existing fields, or by development of new supply areas.

Figure 11



Source: "Potential Supply of Natural Gas in the United States – 2000," Potential Gas Committee.
Canadian Natural Gas Market Review & Outlook, May 2001.
"North American Gas Trends - 2000," Arthur Andersen/Cambridge Energy Research Associates.

Frontier Supply Regions

"Frontier" supply areas are regions believed or known to contain large undeveloped reserves for which little or no delivery infrastructure currently is in place. Alaska is one area; others include: deepwater Gulf of Mexico, Northwestern Canada (Alberta, British Columbia, Mackenzie Delta and Valley), U.S. Rockies, and U.S. coal-bed methane production (principally in Wyoming).

Though Alaska gas is farther away from the North American pipeline grid than any of the other areas, that fact alone does not mean that it will be developed last or valued less. Development of all frontier areas will require substantial investment, not only in exploration and drilling under adverse weather and terrain conditions, but also in infrastructure and facilities such as compression, treating, processing, gathering and pipelines. As noted in Chapter 1, current industry structure makes coordinated planning of such development quite difficult. By virtue of the long history of oil production in Alaska, and existing investment in North Slope infrastructure (seismic information, personnel, roads, etc.), Alaska gas development is more advanced than most of the other areas. The companies that will be producing most of Alaska's gas – Exxon Mobil, Phillips, and BP Amoco – are large, established energy producers with access to financial capital and expertise. In addition, partners in one of the primary pipeline proposals – the Alaska Highway route – are established, experienced pipeline companies that have been organized and functioning since the late 1970s. Many of the necessary permits for that project are already in hand.

In addition, ANS gas production is relatively rich in NGL while some of the other areas are not. Coal-bed methane, for example, has no NGL but does have high levels of carbon dioxide and other impurities that must be removed. Treating and conditioning will add substantially to the cost of delivering that gas to the pipeline grid but unlike NGL, those costs will result in little or no offsetting sales value.

Production characteristics of two of the frontier areas – Gulf of Mexico and coal-gas – are particularly risky from the perspective of large up-front investments in facilities and other infrastructure. Production from wells in these areas tend to exhibit a brief "pop" of early production that tails off to low (albeit steady and long-lived) production thereafter. Gulf production in particular has caused great concern in this regard – new wells there have shown steep decline patterns.

In short, Alaska's existing status as a major oil producing region, coupled with the head-start (almost actual start) it experienced in the late 1970s positions it well in the competition it faces from other frontier supply areas in North America.

What North American Markets Will ANS Gas and NGL Serve?

Assuming that North American demand projections are realized, and that those projections result in development and integration of ANS gas and NGL, the two remaining factors of critical importance to its valuation concern which downstream markets ANS supplies will serve, and how the costs of shipping gas to those markets will be determined and applied in setting values in Alaska. Alaska gas and NGL most likely will be moved to North America via a dense-phase pipeline (one carrying gas and NGL in the same stream) that traverses or terminates in Alberta, Canada. Though LNG and Gas-to-Liquids (GTL) markets and related facilities also are potential outlets, they appear at this time to be secondary to pipeline transport.

Intermediate and Destination Markets. For purposes of analyzing determinants of ANS gas and NGL value, it is useful to distinguish two kinds of gas marketplaces in North America. Some are locations where end-users (or the local retail distributor that delivers to them) buy and consume gas. Call these "destination" markets. They ultimately are the destination points for gas produced and transported within North America. An "intermediate" marketplace is located upstream of destination markets, but downstream of individual gas wells or fields. These are places where gas supplies are aggregated, stored, traded, and routed on to destination markets. These were described in Chapter 1 as production-area "market centers" or "hubs." Transactions at these locations occur primarily between commercial parties (producers and marketers), with little or no involvement of end-users.

Large destination markets like Chicago and California are served by more than one upstream intermediate market and, conversely, large intermediate markets like Southwest Wyoming and West Texas, can reach more than one downstream destination market. Some Gulf Coast areas enjoy both attributes – they are at the same time aggregation points for gas moving to downstream destination markets but also serve large nearby consumers.

Prices at destination markets and intermediate markets are greatly influenced by the number of supply or sales options available to them. For example, a destination market capable of receiving gas flows from a number of different upstream hubs provides valuable options for consumers there, and prices reflect those options. They are lower and more stable than prices paid by consumers in markets served by fewer upstream hubs.

For gas producers and other sellers, the same is true of upstream hubs – those with gas at a hub capable of routing supplies to more than one destination market typically enjoy higher and less volatile prices than those with supplies at a hub that serves only one downstream consumption market.

The large pipeline corridors spanning the North American gas grid are connections among intermediate markets and destination markets. Prices across the system adjust to prevailing market conditions at each node, and reflect the capacity and cost of transportation between nodes. Observed price differences between some pairs of nodes remain quite stable over time, reflecting a balance between gas flows and transport capacity. Other pairs experience volatile price relationships, caused by periodic imbalances in available supplies or demands relative to interconnecting capacity.

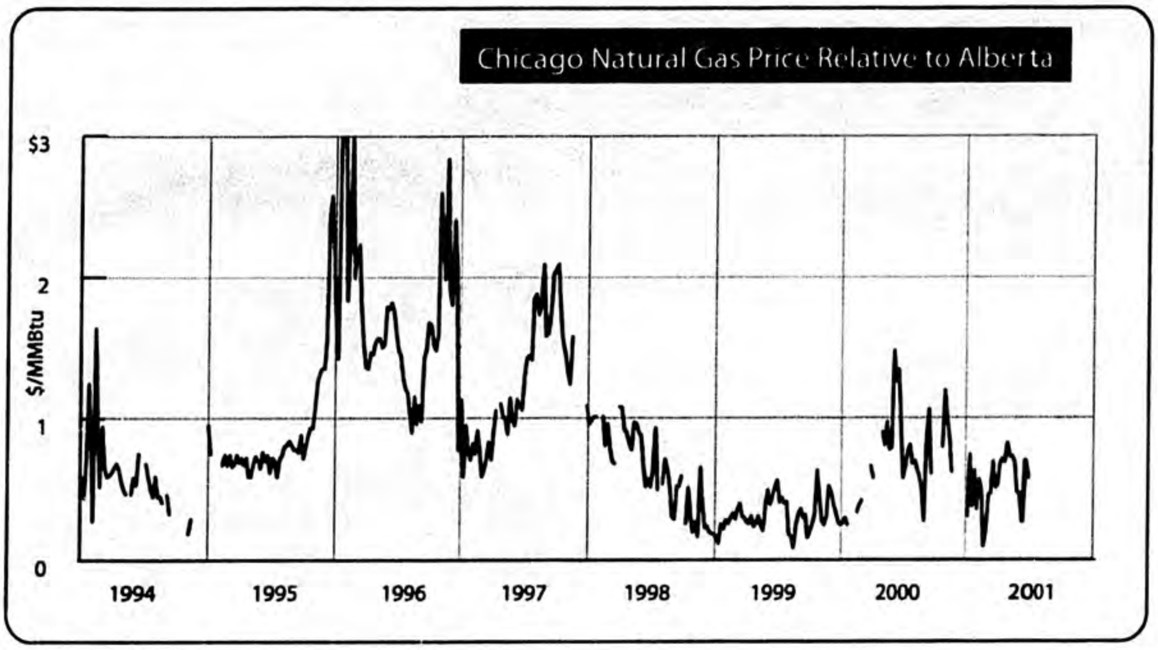
This distinction between intermediate and destination marketplaces applies to gas. For NGL the situation is somewhat different. As described in Chapter 2, there is no comparable pipeline grid and system of hubs for NGL to that which serves gas. Rather, NGL typically is first extracted upstream, near the point of gas production, then piped or truck downstream to one of a relatively few fractionation centers where final NGL products are produced and sold, usually to nearby large customers such as petrochemical companies. These fractionation centers can be considered analogous to destination markets for NGL.

The Potential Role of Alberta in Valuation of ANS Gas and NGL

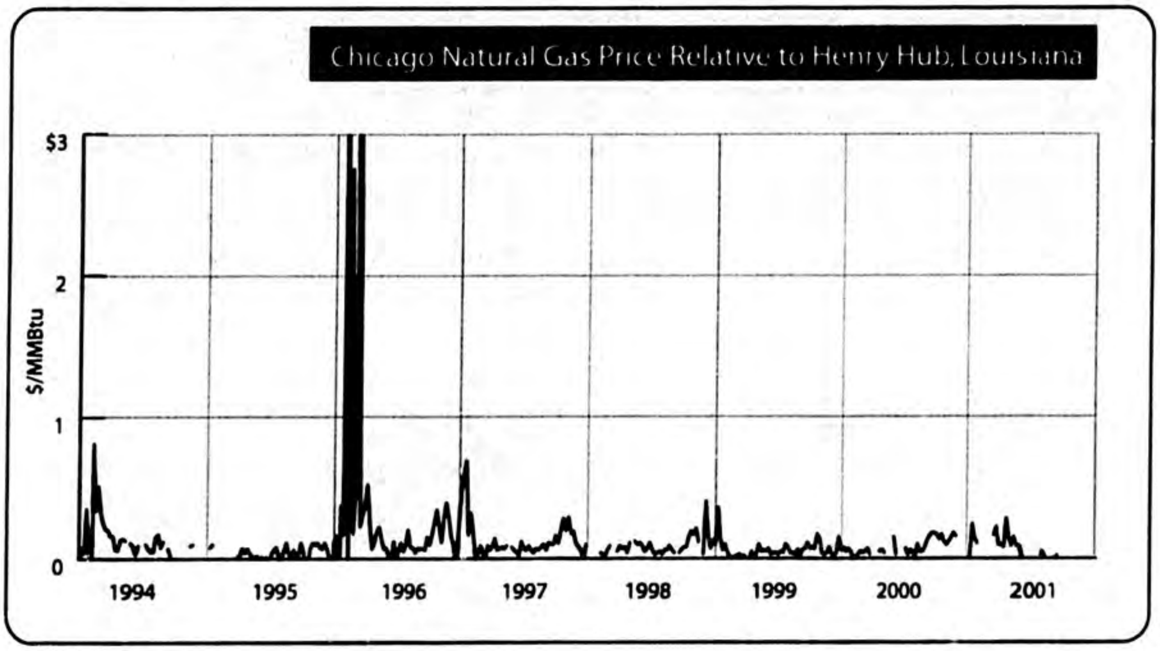
Under most of the pipeline transport options proposed for ANS gas, the routing will traverse and most likely terminate in Alberta, Canada. Alberta is an <u>intermediate</u> marketplace on the North American gas grid, but a <u>destination</u> marketplace for NGL. These facts point to some important questions whose answers in years to come will greatly affect ANS valuation. First, what are the downstream destination markets accessible to gas that is aggregated in Alberta, and what are current and expected transport costs and capacity to them? Second, if ANS gas is routed in such a way as to bypass (or "bullet through") Alberta in an effort to reach higher-value downstream <u>gas</u> markets, will NGL values at those markets suffer compared to the sales opportunities in Alberta? And third, if ANS gas and NGL bypass Alberta, where will it go?

With respect to gas, the Alberta marketplace has a rough history. Though there is an established hub, or market center in Alberta that provides support facilities such as storage and trading services (actually there are several such hubs – See Figure 6 in Chapter 1), throughout its history to date, Alberta gas and the pipelines that carry it to downstream destination markets have failed to achieve a stable role in North American markets because production and takeaway pipeline capacity have not grown in a balanced way. This can be seen in the pattern of Alberta prices shown in Figure 12, which shows that prices in Alberta fluctuate substantially compared to its primary destination market – Chicago. By contrast, prices at Henry Hub in South Louisiana have remained in steady alignment with Chicago prices.

Figure 12



Source: Natural Gas Week.



Source: Natural Gas Week.

These price patterns demonstrate two important aspects of gas valuation. First, the capacity and cost of transport links between a destination market and the upstream intermediate markets that serve it have a direct and potentially sizable influence on upstream prices. Without an ongoing balance between supplies and transport capacity, upstream prices are subject to considerable volatility. Also, the price patterns shown highlight the vulnerability of an intermediate marketplace, like Alberta, that sends most of its supplies to one downstream destination market. While some Alberta gas can, and does, flow to Western U.S. markets, the bulk of it is shipped to the upper Midwest. In that situation, any excess pipeline capacity or bottlenecks that develop between Alberta and Chicago have an immediate effect on Alberta prices. If Alberta served Chicago and Western markets more equally, that effect would be dampened and Alberta prices would be more stable as a result.

The Alliance Pipeline. The prices shown in Figure 12 do not reflect much experience with the presence of the newest pipeline serving Alberta: Alliance. That pipeline went into service in December 2000. It carries Western Canadian gas to a point near Chicago. There the gas stream is processed at the Aux Sable plant, built in conjunction with the pipeline, and then is delivered to sales markets in the upper Midwest or to markets in the Northeast. The Aux Sable plant is the largest in North America in terms of gas throughput.

The Alliance/Aux Sable arrangement, where gas and raw mix NGL are transported together for a long distance, is unique among North American pipelines, but similar to the pipeline and processing arrangement envisioned for ANS gas. The advantage of that arrangement is that it transports raw mix NGL at lower cost than if that mix were extracted at or near production (as is the norm) and transported via a separate pipeline to a downstream fractionation center and finished products market. The disadvantage of that system is that it isolates its gas stream from the North American grid until it reaches markets near Chicago. This is because the grid does not accept gas containing raw mix NGL. That isolation limits sales and market options available to Alliance gas, though its proximity to large markets in Chicago mitigates this problem. In effect the Alliance pipeline is a large, long gathering system that delivers to a single processing plant. Only then can the gas enter the pipeline grid and participate in the merchant activities that take place along the grid.

The Alliance system has created excess pipeline capacity serving production in Western Canada. Accordingly, prices there are today little different than downstream market prices in Chicago, especially in comparison to past years when the reverse situation – not enough pipeline capacity – had depressed Alberta prices relative to Chicago. The situation today is favorable to producers in Alberta, but over the longer term, the see-saw relationship of pipeline capacity and production that has plagued Alberta over the years makes it difficult to assess its true and permanent economic role in North American gas consumption markets vis-à-vis other producing areas. The uncertainty impedes investment in exploration and transport facilities.

How Will ANS Gas and NGL Affect Alberta Markets? If flows into Alberta become commingled with other supplies that are aggregated there, ANS gas and NGL will become subject to the same market forces that act on all Alberta supplies. As noted, to date those forces have created periods of benefit to producers with gas there, as well as periods of very low prices when supplies faced constrained transport outlets. It is possible that introduction of a large new supply source that ANS gas would represent could bring the region to a size threshold sufficient to create a stable marketplace there, particularly if that size prompted creation or expansion of takeaway pipeline routes serving destination markets other than the upper Midwest. In that scenario, the Alberta region could become a northern "Henry Hub" with volumes from Alaska solidifying the Alberta region as a permanent and active marketplace for gas and NGL. As shown by Henry Hub, that reputation itself encourages investment in services and facilities that enhance trading, such as storage, organized trading markets, and take-away pipeline capacity. Financial markets also could recognize Alberta as a legitimate location for establishment of a northern futures market, for gas and/or NGL. That, of course, would further enhance the region's legitimacy as a stable and reliable market center.

But whether ANS gas and NGL will bring about market stability in Alberta is not a certainty. The added ANS volumes may simply offset production declines in that region, both for gas and NGL, and even should the ANS volumes represent incremental supplies there, the critical factor influencing Alberta prices is pipeline takeaway capacity relative to those supplies. Excess pipeline capacity can be expected to produce strong prices in Alberta, relative to downstream markets, while constrained capacity will generate weak prices. Alone, nothing about the increased size of gas supplies available in Alberta upon the arrival of ANS gas will change that fundamental fact. While excess capacity would benefit ANS producers and the State, its presence sets up the very see-saw phenomenon of alternating excess and constrained capacity that Alberta has experienced over the years. The same has occurred in other regions as well, the U.S. Rockies being a prime example. Experience shows that when pipeline capacity serving a region is tipped out of balance with the region's production capacity, it is difficult to regain that balance, and the result is fluctuating periods of abnormally low and abnormally high gas prices.

That fact highlights the importance of today's estimates of the volume of ANS gas that will be produced and piped into Alberta, and – equally important – the expected volume of Alberta gas (including perhaps supplies from the MacKenzie Delta and Valley areas) that also will be offered to market at that time. Such volume estimates are critical in determining how much takeaway pipeline capacity should be added, if any. If ANS plus Alberta volumes in 2010 exceed expectations, pipeline capacity out of Alberta may not accommodate it, with resulting low prices. Given the long lead-time for pipeline construction, such estimates of joint ANS/Alberta/MacKenzie production must be made and evaluated now, not after ANS gas begins to flow.

A second factor highlighted by Alberta's uneven development to date is the value of diversification of sales options. The value of ANS gas will be enhanced if, when it begins to flow to markets, it can readily access two or more large destination markets. The ability of ANS gas to flow either to Western markets such as California, or to Midwestern markets such as Chicago will give ANS producers valuable options. Again, given the long lead time associated with expansion or construction of pipelines from Alberta to either Western or Midwestern markets, it is vital that such pipeline proposals and plans be evaluated in conjunction with ANS development plans.

Can ANS Gas and NGL By-Pass Alberta?

If ANS gas producers determine that injecting their production into the Alberta marketplace is likely to subject them to too much uncertainty in terms of the rates and capacity of takeaway pipelines, they may devise means to avoid the Alberta market entirely. There are two potential ways to accomplish such a by-pass. First, the pipeline constructed to handle ANS gas could be extended to other markets downstream of Alberta. Or, the producers could obtain long-term commitments in advance of production on existing takeaway pipelines to assure themselves adequate capacity to move beyond Alberta at known, consistent rates.

These options pose a number of hazards and costs for ANS producers. The cost of a pipeline system extending from, say, Alaska's North Slope to Chicago would be enormous. Moreover it would effectively lock ANS producers into a single downstream sales market. In addition, if such a pipeline were, as planned, a dense-phase line carrying both gas and NGL, the NGL portion of the stream would by-pass a market (in Alberta) that may well be superior to any available near Chicago. Alberta is home to a large petrochemical industry (which Chicago lacks) that would provide a substantial market for NGL. Arranging capacity on takeaway pipelines now serving Alberta would indeed enable ANS producers to sell NGL in Alberta and ship gas downstream to potentially more attractive sales markets, but that option must confront the risk of committing to a sizable portion of existing lines' capacity.

These are difficult choices for ANS producers but ones that, once taken, will substantially affect the value realized by them for years to come. One of the major conclusions of this Report with respect to royalty determination is that as those choices are being made and as events surrounding them unfold, it is critical that producers and the State share detailed information concerning the actual disposition of ANS gas and NGL. Information relating to transportation routes and costs, and ultimate sales realizations in whichever markets ANS gas and NGL ultimately reach should be made available to the State under either proceeds-based, or value-based royalty methods.

Netback Calculations for ANS Gas and NGL

The amount North America buyers in Alberta or markets further downstream will pay producers for ANS gas and NGL depends on prevailing price levels for gas and NGL available to them in other supply markets, and on the cost of moving ANS gas and NGL.

In the gas and NGL business the term "netback price" refers to a calculated, or estimated price, as opposed to an observed arms-length transaction price. A netback price is calculated by deducting transportation costs required to move gas or NGL from a producing area (where the netback is being applied) to a downstream market area where transactions occur and prices are collected and published. The use of netbacks is quite common to derive gas and NGL values at remote points in North America

The economic rationale for calculating and using a netback derivation of value is that competitive buying and selling should, in theory, force prices at different locations to equal the cost of transportation between them. If that relationship did not hold, it would give rise to an arbitrage profit opportunity. The actions of those seeking to exploit that opportunity would return the price differential to transport costs. The same concept also can be used to estimate the price of one product based upon observed prices for a second product and the costs of converting one into the other. So, for example, one could estimate prices for NGL in one location based upon prices for gas in a second location, less transport and processing costs.

The netback methodology for estimating value, though simple in theory (sales price less transport costs) requires special care in practice. Problems can arise in the determination and application of transport cost data in the formula. When a pipeline has excess capacity, its fully-allocated cost of service is little or no different that if it were running full (variable operating costs could differ, but these are normally a small part of total pipeline costs). But market forces tend to reduce the rates paid for transportation on a pipeline that has excess capacity to rates below those derived to recover total costs. Thus the actual price paid by a shipper using a line with excess capacity would be less than the pipeline's full cost of service.

The reverse could be true in the event of a pipeline bottleneck. In that case shippers competing to assure that their gas flows through the constrained line can reduce sales prices – effectively bidding up the price paid for using the pipeline. This time the true cost of using such a line, for purposes of applying a netback pricing methodology, would be higher than its fully-allocated cost of service. This has happened periodically in Alberta over the years, when pipeline capacity out of the area has been constrained. Competition among Alberta producers bid up transport rates, usually through purchases of capacity in the secondary transportation market, to assure their gas moves through the constrained pipe. In that circumstance, a netback value utilizing the pipeline's tariff transportation rate would overstate actual gas sales value.

The conditions posed above – surplus or deficiency of pipeline capacity – are not uncommon and therefore except by coincidence, the actual economic costs to shippers of using a pipeline are unlikely to match up with tariff rates or other full cost-recovery transportation rates. The same is true for transportation and processing of NGL. The mis-match arises from the fact that gas and NGL pipelines and plants are large, long-lived sunk investments that are susceptible to fluctuating throughput. That can create for them periods of above-normal rates reflecting scarcity rents, and periods of below-normal rates that under-recover full costs.

Notwithstanding these complications associated with its use, the netback methodology is frequently used by gas buyers and sellers and, with appropriate care and access to relevant information concerning transport and processing costs, can be a good means of determining upstream values based upon downstream sales prices.

The potential complications warrant special attention in the case of Alaska gas and NGL because sufficient local trading is not likely to occur in Alaska to establish local, transaction-based measures of value and some type of netback methodology is likely to be used by producers and buyers of ANS gas to arrive at wellhead transaction prices. That task will be made somewhat more difficult if a single pipeline moves all ANS production because it will almost never be the case that the pipeline is optimally loaded, and accordingly there could be persistent and potentially unobservable transport rates above full pipeline costs, or persistent discounts below full costs. Either would make use of a netback methodology more difficult. It is in part for this reason that the State and producers should implement a period of intensive analysis and sharing of information during the initial years of ANS production in order to comprehend fully the nuances of netback value measurements for ANS gas and NGL. This suggestion is described in more detail in Chapter 6.

Chapter 4

Economic Aspects of Royalty

A royalty arrangement is a partnership between a resource owner and a resource developer. One contributes the resource, the other contributes expertise, investment, and effort to develop and "commercialize" the resource. A royalty agreement is a contractual mechanism for sharing that enterprise's benefits and responsibilities between these partners.

While the economic purpose and benefit of royalty is to capture efficiencies of specialization, delegation of development and marketing powers by the resource owner to a non-owner creates two kinds of problems that the partnership, through its contractual agreement, must address. The first is principal/agent problems arising from the fact that once the enterprise is launched the developer (the owner's agent in commercializing the resource) is likely to possess superior information, which it can be expected to exploit to its advantage where possible. The other is problems stemming from the difficulty (or impossibility) of using a long-term contract to provide certainty and stability to the partnership, while at the same time enabling adaptation to changed circumstance.

Principal/Agent Problems

In theory, an agent (in this case a gas production company, or lessee under an oil and gas lease) always acts in harmony with the principal's (mineral owner; lessor) interests. But in practice, agents can and often do pursue their own interests, even when doing so harms the principal. Where that danger is present and the parties foresee that it may cause problems, contractual agreements between principals and agents will specify oversight and monitoring mechanisms to police agent conduct.

A primary tool of oversight in gas royalty agreements is the lessor's right periodically to audit a producer's financial, production, and operating records to determine if performance has been in accordance with lease terms. That right serves both as a means to correct past errors in royalty sharing, and as an incentive for the producer to establish procedures and data collection that will demonstrate its faithful performance of obligations. Yet, as many producers and mineral owners can attest, audits often are complex, costly, and inevitably involve interpretation and judgment. These weaken its power to fully assure producer performance.

When such oversight is not possible or proves too costly to administer, a principal may seek to structure the agent's compensation in some creative way so as to align incentives. It would be possible of course for a gas producer to be paid by a mineral owner based upon time and expenses, with no payment linked to the volume or value oil and gas produced and sold. But clearly a producer under that deal has little or no incentive to maximize development value, or to operate efficiently. In contrast, permitting the producer to keep all product upon payment of a fixed amount – effectively buying the mineral from its owner – presents the difficult task for both parties of arriving at a price, with little or no information about future production levels or revenues.

For gas royalty agreements, a better compensation scheme than either of these extremes is one in which lessor and lessee share revenues from production, or share in physical production. Production or revenue sharing does better align producer and mineral owner incentives, but it is subject to its own set of problems. For example, when revenues are shared (as opposed to physical volumes) the producer is positioned to exploit its natural advantage over the mineral owner regarding important revenue-related data such as reserve size, production levels, NGL content, costs, prices and sales opportunities. In a revenue sharing arrangement where that kind of information is used, the producer can capture a larger-than-agreed share by withholding or distorting such information. That can result from intentional acts of deception, but also simply because information used to calculate revenues and costs often requires interpretation and analysis. It is natural for a producer to apply interpretations favorable to it and to create and share information consistent with that interpretation.

Unfortunately, recognizing these problems does not aid much in their resolution. Audits and litigation of detailed contract terms are costly forms of contract administration. Writing a contract that accurately and fully describes which among many possible interpretations is the "correct" one is difficult at best. Even if such language could be agreed to, the danger remains that the lessor won't be able to detect and enforce it, even with audit rights, or to take steps to correct faulty sharing.

Contract Adaptability Problems

Oil and gas leases normally last for many years, well beyond the time frame that a lessor (mineral owner) and a lessee (producer) could be expected to predict how production and value determination will unfold. Royalty terms and sharing methodologies that today efficiently carry out the parties' intentions, can become onerous to one side or the other as circumstances change. There is no perfect royalty agreement in an ever-changing market environment – one capable of continuously implementing (at acceptable cost) the parties' initial intentions. Every agreement entails a tradeoff between the low-adaptability and high administrative cost of highly specified agreements that carry a degree of certainty, and the hassle and costs of (and potential hold-up associated with) renegotiating agreements with flexible but open-ended terms.

Types of Gas Royalty Sharing Agreements

The following is a list of royalty sharing principles, methodologies, and procedures often appearing in oil and gas royalty agreements:

1. Royalty paid in value
    a. Lessee producer's wellhead sale
    b. Wellhead sales proceeds of other, comparably-situated producers
    c. Lessee producer's sale proceeds from downstream sales points (netback calculations).
    d. Market value measures constructed from sale activity at major downstream markets to which lessee producer's gas could, or should, flow (netback calculations).
2. Royalty in Kind

These methods of royalty determination are briefly described below, with explanation of the economic benefits underlying them and difficulties presented by each.

Royalty in Value

1. Proceeds from producer's wellhead sales.

Though wellhead sales are not common today, this measure of value still appears in many leases. Clearly this value measure is the simplest and easiest to determine. The potential problems with its use relate to determination that the producer's proceeds are not artificially depressed (owing perhaps to sales to an affiliate, or to an independent party where compensation is received in forms other than sales proceeds), or that the producer's marketing efforts have been adequate to obtain the highest available proceeds.

2. Wellhead sales proceeds of other, comparably-situated producers.

This lease term evolved as a means of assuring that a producer's marketing efforts were adequate to obtain proceeds at least equal to those being obtained by comparable sellers. It is not an easy formulation to implement owing to the cost of obtaining relevant information concerning third-party transactions. Even where such information is available, the difficulty in implementing such a measure lies in performing an adequate comparison of sales terms other than price, and adjusting for legitimate sources of price differences such as gas quality or location.

3. Lessee producer's sale proceeds from downstream sales points (netback calculations).

Under this measure, a producer pays royalty based upon sales revenue it obtains for gas and NGL produced and sold. For sales that occur downstream from the wellhead, this methodology is intended to document actual sales and actual costs incurred to move and sell gas and NGL at those downstream locations. Some portion of such costs often are deducted from revenue to determine the lessor's share of value. In theory this arrangement can give a precise measure of value received by producer at the wellhead even when no wellhead sales occur. That makes it a highly desirable measure. Weighed against that substantial benefit, though, are a number of costs and administrative challenges:

a. The producer is likely to have superior access to information needed to make value determination. That leads to opportunity to cheat; when that occurs and is not detected, the lessor is deprived of his agreed-upon share. When it occurs and is detected, trust is destroyed, potentially raising future compliance and enforcement costs. That in turn heightens producer incentive to cheat, and the cycle continues. The result can lead to expenditure of resources by both sides that cut into the economic benefit to both parties of gas and NGL sales.

b. Because gas is transported in a displacement pipeline network, often it is not possible accurately to physically trace gas from point of production to point of sale. Therefore, by necessity, both revenues and costs in a net proceeds measure are accounting determinations that result from allocation procedures. These may bear little or no resemblance to true revenues and economic costs. In addition, the producer may aggregate lessor's gas with gas from other sources and provide valuable services to customers with the resulting "package" of gas. Attributing a portion of the value of such services to a particular lessor's gas is, again, a difficult task, involving accounting allocations that may bear little relationship to the value-added by any particular gas source, and which may be subject to manipulation and distortion by the producer to reduce royalty sharing.

c. Affiliate transactions – likely to be present in movement and sale of ANS gas and NGL – also present opportunity for a producer to shift costs to avoid royalty payments. Producers that use affiliates to gather, process, transport or provide other services prior to sale have an incentive to inflate the costs reported for those activities so as to reduce the lessor's share of value.

d. The presence of NGL in Alaska gas, and the likelihood that such NGL will be transported long distances in the same stream as gas, complicates net proceeds determination because the cost of such joint transportation must be allocated between gas and NGL.

4. Market value measures constructed from third-party transactions at downstream markets (netback calculations).

Under this approach royalty payments use an agreed-upon downstream published price index, less agreed-upon market indicators of costs for moving of gas and NGL to that downstream sales point.

This approach does not require specialized information that only the producer is likely to possess and must share with lessor, and that puts them on more equal footing. It eliminates the opportunity for a producer to manipulate information to its advantage, and eliminates the perceived need by the lessor to impose costly compliance standards and procedures for producer to perform (or seek in turn to avoid or distort). Weighed against these benefits are the following disadvantages:

a. The downstream market index chosen may not reliably reflect value for the production covered by the royalty agreement. For example, the index could be subject to manipulation by one or more buyers or sellers at the index location. In addition, the agreed-upon index may be subject to short-run or long-run changes that do not accurately reflect changes in value of the royalty production. Also, the producer may find and sell into more lucrative markets than those chosen for index.

b. Published data for NGL transportation rates, processing costs and fractionation costs are not as readily available as published gas prices; in addition, such transport and processing information requires a greater level of interpretation. That presents opportunity for manipulation, distortion, or at least disagreement about, the meaning and application of such information.

c. Transport rates for ANS gas are likely to be highly influenced by the dominance of the three largest ANS producers in the takeaway pipeline. Even if producers do not own that pipeline, they still are likely to dominate its use and affect the structure and level of rates paid. This will affect value determination for both gas and NGL.

d. Market rates paid for transportation can differ from tariff rates, and short-term market rates may differ from long-term market rates. These complicate use of independent rates in netback calculations. To the extent that producers are positioned to affect collection and presentation of such information, the opportunity exists for manipulation.

Royalty in Kind

It is relatively rare that gas royalty is paid in gas. Unlike oil, gas cannot easily be stored at the lease by the lessor and disposed of separately from the lessee's production. That could potentially require duplicate or costly facilities. Instead, royalty-in-kind for gas, when it occurs, is more likely to involve separate contracting by the lessor or royalty-in-kind purchaser for use of the facilities also used by the lessee. It is possible for a lessor to administer such contracting itself – though that would appear to destroy the primary reason for a royalty partnership (specialization) – or it could contract with a "commercializer" that is distinct from the original lessee. Such contracting, though, presents the same kinds of problems as those discussed above inherent in the royalty relationship: establishing verifiable value principles, and implementing monitoring or compensation mechanisms. One advantage to royalty-in-kind is the possibility of harnessing periodic competition among potential marketers, including the lessee producer, to achieve maximum value. This alone is reason for a lessor to retain the option to switch periodically and with due notice, from royalty-in-value to royalty-in-kind.

Chapter 5

Alaska State Lease Provisions and Historical Experience with Oil Royalty

The discussion in this Chapter is not intended to provide a legal interpretation of the rights and obligations of the State and its oil and gas lessees. Rather, it is intended to illustrate and highlight issues and complexities likely to be encountered in valuation of the State's royalty gas and NGL.

Historical Experience with ANS Oil Royalty

ANS crude oil royalty is based on a determination of the value of the oil at the point of production, sometimes referred to as "wellhead value." For purposes of computing royalties, the value of ANS crude oil at the point of production has been computed both by the producers and the State using a netback mechanism since oil production first came on stream in mid-1977. Under that netback mechanism, value at the point of production is based on the value of ANS crude oil in destination markets where it is sold or consumed, less a measure of the cost associated with transporting the product from the North Slope to those markets.

The use of a netback approach to wellhead value determination arose from the way in which ANS crude oil was sold and consumed – in destination markets rather than at the point of production itself. Historically, the vast majority of ANS crude oil production has been transported thousands of miles from the North Slope of Alaska before being sold and consumed in destination markets. Today almost all ANS production is sold to refiners on the U.S. West Coast. Until recently, however, large volumes of ANS production were sold in markets as distant as the U.S. East Coast, the Caribbean and/or Asia.

Since most ANS crude oil has been sold by producers in destination markets far from the North Slope, nearly all of the transactional information regarding ANS value comes from sales of ANS in destination markets, rather than sales at the point of production itself. To the extent sales occurred on the North Slope, those transactions have almost always themselves incorporated a netback formula, with the price determined from ANS prices or values in destination markets, less a measure of transportation costs to those markets.

Alaska's Oil and Gas Lease Provisions

The companies that will produce gas from the Prudhoe Bay Unit and Pt. Thomson Unit signed lease contracts and royalty settlement agreements with the State of Alaska that will govern the calculation of the value of the State's royalty gas. The leases establish the State's right to retain a royalty share of production – usually 12.5 percent of gross production – and allow the State to take its royalty share in-kind or in-value. When the State takes its royalty in-kind, it sells its royalty share to third parties. When the State takes its royalty in-value, the lessees pay a cash value for it. The leases provide a mechanism to calculate the cash value of royalty paid in-value.

The DL-1 Lease Form.

Most of the leases in the Prudhoe Bay Unit are DL-1 form leases originally adopted by the State as administrative regulations in 1959. Some of the leases in the Point Thomson Unit also are DL-1 leases but many are new-form leases issued after 1978. There are several important differences between the DL-1 and new-form leases, but both establish the size of the State's royalty share and give the State the option to take its royalty share in-kind or in-value. They differ in the terms that describe the mechanisms to calculate value for royalty the State takes in-value.

Paragraphs 15 and 16 of the form DL-1 lease read as follows:

> ¶ 15. ROYALTY IN VALUE. At the option of the Lessor, which may be exercised from time to time upon not less than six months notice to Lessee, and in lieu of royalty in kind, Lessee shall pay to Lessor, the field market price or value at the well of all royalty oil and/or gas....
>
> ¶ 16. PRICE. The field market price or value of royalty oil or gas shall not be less than the highest of: (1) The price actually paid or agreed to be paid to Lessee at the well by the purchaser thereof, if any; or (2) The posted price of Lessee in the field for such oil or gas at the well, if any; or (3) The prevailing price received by other producers in the field at the well for oil of like grade and gravity or gas of like kind and quality at the time such oil or gas is removed from said land or run into storage, or such gas is delivered to an extraction plant.

Disagreements between the State and the Prudhoe Bay Unit lessees concerning DL-1 lease terms led to the *ANS Royalty Litigation* in 1977. Over the course of that litigation many of the lease terms were interpreted by the Superior Court and modified by royalty settlement agreements. Some of the issues ruled on include:

> 1. The cash value of the state's royalty share is equal to the price of the royalty oil or gas in the market(s) where it is sold, minus the cost of transportation to deliver that oil or gas to market.
>
> 2. Each lessee deducts its own reasonable and actual transportation cost from the price in the market(s) where its gas is sold, which may differ from the market value of that transportation.
>
> 3. In addition to transportation costs, the State bears field costs on royalty taken in-kind. When the State takes its royalty in-value, the lessees provide it free of field costs.
>
> 4. An early Superior Court ruling (that was later superseded by the 1980 royalty settlement agreements) held that the State could take its royalty in-kind only if it received at least as much from sale of the oil to royalty in-kind purchasers as it would have received if lessees paid royalty in value. Only then would taking the royalty in-kind meet the constitutional requirement that it be "in the best interests of the State and for the maximum benefit of its people."

The New-Form Lease.

In 1980 the State began issuing new-form leases, with royalty and value terms intended to minimize opportunities for dispute over royalty value. These leases have never been litigated. Like the DL-1 leases, the new-form lease describes a variety of mechanisms to calculate royalty value and the lessee must use the mechanism that yields the highest value.

An example of the value term found in the new-form lease is illustrated as follows:

¶ 36. VALUE.

(a) For the purposes of computing royalties due under this lease, the value of royalty oil, gas, or associated substances shall not be less than the highest of
(1) the field price received by the lessee for the oil, gas, or associated substances.
(2) the volume-weighted average of the three highest field prices received by other producers in the same field or area....
the lessee's posted price in the field....
the volume-weighted average of the three highest posted prices in the same field...

(b) If oil, gas, or associated substances are sold away from the leased or unit area, the term 'field price' in subparagraph (a) above will be the cash value of all consideration received by the lessee or other producer from the purchaser of the oil, gas, or associated substances, less the reasonable costs of transportation away from the lease or unit area to the point of sale. The 'reasonable costs of transportation' are as defined in 11 AAC 83.228 and 11 AAC 83.229 as those regulations exist on the effective date of this lease.

(c) In the event the lessee does not sell in an arm's length transaction the oil, gas, or associated substances, the term 'field price' in subparagraphs (a) and (b) above will mean the price the lessee would expect to receive for the oil, gas, or associated substances if the lessee did sell the oil, gas, or associated substances in an arm's-length transaction, minus reasonable costs of transportation....The lessee must determine this price in a consistent and logical manner using information available to the lessee and report that price to the state.

(d) The state may establish minimum values for the purposes of computing royalty on oil, gas, or associated substances obtained from this lease, with consideration being given to the price actually received by the lessee, to the price or prices paid in the same field or area...to posted prices, to prices received by the lessee and/or other producers from sales occurring away form the leased area, and/or to other relevant matters. In establishing min m values, the state may use, but is not limited to, the methodology for determining 'prevailing value' as defined in 11 AAC 83.227. Each minimum value determination will be made only after the lessee has been given notice and a reasonable opportunity to be heard. Under this provision, it is expressly agreed that the minimum value of royalty oil, gas, or associated substances under this lease may not necessarily equal, and may exceed, the price of the oil, gas, or associated substances.

The new-form lease explicitly acknowledges that the lessees will sell royalty gas in distant markets and that prices of gas in these markets are appropriate data in determining royalty value. The lessees are allowed to deduct their own reasonable costs of transportation.

Paragraph 36(d) allows the State to define the minimum value for its royalty. Although the lessees retain a mechanism to voice disagreement with the State, the lessee must pay the higher-of the minimum value or the highest price yielded from the other lease terms. The new-form lease also requires the State to evaluate the same kinds of information that it might consider when establishing the Paragraph 15 value under the DL-1 lease. A critical distinction between Paragraph 15 and Paragraph 36(d) is that the lessees must accept Paragraph 36(d) as determined by the state to be the minimum value for their royalty obligation.

Disputes Concerning Proper Calculation of Royalty Values

Settled ANS Gas Royalty Disputes. A 1980 royalty settlement agreement anticipated the construction of a pipeline to take ANS gas from the North Slope for Prudhoe Bay only. It includes details about how the State and the lessees are to account for the royalty deduction for the cost of removing CO2 and other impurities in a gas conditioning plant. The conditioning costs to be deducted from the value of royalty gas will depend on whether the lessees own the plant and whether the plant is a unit facility or part of a pipeline project. The magnitude of conditioning costs will not be known until the gas conditioning plant is built.

The same agreement provides a formula for calculation of Prudhoe Bay Unit field costs on oil and gas that would apply to all royalty dispositions whether taken in-kind or in-value. At present, the field cost deduction for gas produced from the Prudhoe Bay Unit calculated per the 1980 agreement is $0.19 per mcf.

In 1995, near the conclusion of the *ANS Royalty Litigation*, the State and lessees entered into several gas royalty settlement agreements and set out royalty valuation provisions that differ from the requirements of the DL-1 lease. These provisions apply only to sales of royalty bearing gas referred to as "Local Gas," defined as dispositions of royalty bearing gas volumes less than 50 mmcf/d. These settlements also determined a royalty deduction on "Blendable NGLs" produced from the Prudhoe Bay Unit, i.e., NGLs that can be blended with oil for shipment on TAPS.

A significant term in the 1995 gas royalty settlement agreements prohibits the lessees from charging, as a royalty deduction, the cost of Prudhoe Bay's Central Gas Facility on gas sold for deliveries to an ANS gas pipeline project. If a lessee sells "New Gas," defined as a disposition of gas in excess of 50 mmcf/d, the gas royalty settlement agreements leave the question of appropriate valuations and royalty deductions up to the provisions of the DL-1 lease provisions. Volumes of this magnitude would be expected to supply the ANS gas pipeline. In the event that the ANS gas pipeline is built, we understand from DNR that the State will look to Paragraph 15 and 16 of the DL-1 to value most of the royalty gas produced from the Prudhoe Bay Unit. The State and the lessees have not agreed on an interpretation of all of the terms in Paragraph 15 and 16.

Settled ANS Oil Royalty Disputes. From the start of ANS oil production the producers computed royalties using one of two basic approaches: 1) proceeds or 2) a measure of market value. In some instances producers used a combination of the two approaches depending on how they marketed their oil. Where producers sold oil to another party they often based royalties on the proceeds they received in those sales. Where producers used their ANS oil production in their own refineries, they determined royalties based on a measure of market value. In both cases producers netted back these prices to the point of production by subtracting their determination of transportation cost from the North Slope to the point of delivery.

ANS producers used a number of approaches in determining market value for ANS production. In some cases producers constructed market value-based, transparent formulae. These included basing ANS value on the prices of one or more "proxy" crude oils sold in the same destination markets in which ANS was delivered, or basing ANS values on the average price received by the producer in its own sales transactions. In other cases producers determined market value based on a more subjective "assessment" of market factors.

The manner in which the major producers computed royalties was contested by the State for many years and was the subject of litigation between the State and producers in the *ANS Royalty Litigation*. In that litigation the State took issue with the way in which the producers calculated the proceeds they received from sales to third parties and the methods used by producers to determine market value. The State also took issue with many of the cost deductions made by the producers when netting back destination values to the point of production. In the *ANS Royalty Litigation* the State obtained detailed data relating to all transactions entered into by the producers for the purchase, sale, exchange and transport of ANS oil. The State also obtained data from the producers regarding the cost of transporting ANS oil from the North Slope to destination markets. The process of obtaining and analyzing this information in the context of litigation was lengthy and costly, involving the efforts of many people over several years.

The State analyzed the transaction data it obtained from producers during litigation to determine the proceeds actually received by the producers to develop a measure of ANS market value that would closely track prices actually received by ANS producers; it analyzed the information obtained regarding cost deductions to determine appropriate deductions when netting back from destination values. Based on its analysis of producers' transactions, the State made determinations of proceeds and ANS market values that often resulted in large discrepancies relative to the proceeds and market values reported by producers for royalty payments. In some cases these discrepancies amounted to several dollars per barrel over extended periods of time. Likewise, the State's analysis of ANS transportation costs resulted in large differences relative to the costs claimed by the producers.

The State and major producers settled the oil valuation phase of the *ANS Royalty Litigation* in the early 1990s. As a result of these settlements, the three major producers agreed to pay the State a total of $736 million in additional back royalty payments. In addition, the State and major producers agreed on a prospective approach for determining royalty values. The prospective valuation approach incorporated in the royalty settlement agreements between the State and producers established a netback formula for royalty payments that consisted of: 1) a destination value measure, and 2) specified cost deductions for transportation to destination markets. Destination values were established by reference to independent, published market assessments for ANS and other crude oils; transportation deductions were based on agreed-upon costs that were, in some cases, indexed to changes in industry-wide transportation cost measures.

The royalty settlement agreements include provisions that allow either party to "reopen" or renegotiate terms of the valuation formula with respect both to destination valuation and to cost deductions. Either party may reopen in the event it feels the current formula does not produce results that are consistent with true ANS market values. The agreements also specify that if the parties fail to reach agreement on a new formula after one of the parties has formally reopened the negotiation, then their dispute will be settled by binding arbitration.

Since entering into royalty settlement agreement in the early 1990s, the State and producers have reopened agreements on several occasions. In each instance, the parties have been able to reach agreement without arbitration. In some instances, the parties have amended the agreements without resorting to a formal reopener notice.

Knowledge Gained by the State after Years of Analysis The ANS oil royalty settlement agreements between the State and producers have provided a workable, mutually agreeable framework for royalty valuation over the past decade. Implicit in the agreements is recognition of the costs of compliance and enforcement associated with detailed proceeds accounting (and audits) and the potential controversy surrounding a subjective determination of appropriate value measures. Also implicit is recognition of the economy associated with use of independent, publicly available measures of value and costs that are themselves regularly used by industry participants when contracting for the sale or transportation of ANS.

For the State, the agreements have provided a mechanism that enables it to receive a measure of market value for its oil without the need to engage in continuous, detailed auditing of producers' transactions and accounting data. For the producers, the agreements have provided a formula for paying royalties that removes uncertainties as to how to comply with payment provisions of the lease agreements. That certainty is valuable to the producers.

The success of the royalty settlement agreements in striking a balance among the interests of all parties is indicated by the fact that the parties have on occasion renegotiated agreements without the aid of arbitration.

The royalty settlement agreements were negotiated by the State after ANS crude oil production had been flowing for more than a decade. They were negotiated after the State had the opportunity to analyze the way in which ANS was transported and sold. By the time the agreements were put in place the State had reviewed thousands of contracts involving ANS transportation, sales and exchanges, as well as accounting statements used by producers to support cost deductions in their netback calculations.

The experience and expertise gained by the State through its analysis of data and contracts involving ANS transportation and marketing was a key factor in the State's ability to negotiate the prospective royalty valuation formulae contained in the agreements. This experience helped insure that the valuation methodology agreed to by the State accurately captured ANS value at the outset, and that the agreements gave the State the ability to modify terms in the event markets changed going forward.

Since ANS production came on line in the late 1970s, oil markets have undergone several changes that have affected markets into which ANS has been sold. For example, during the first few years of ANS production, crude oil markets were characterized by long-term contractual relationships between producers and buyers. World events in 1979 set in motion a multi-year change in the oil industry that resulted in greater emphasis on short-term or spot markets. This in turn led to a rise in importance of financial or "paper" markets. In short, the world and the way in which crude oil – including ANS – was marketed changed dramatically over the first decade of ANS production in a way that was not anticipated by market participants when ANS production first came on line.

Oil markets have continued to evolve as ANS production has declined since the early 1990s. Today, all ANS production is marketed on the U.S. West Coast or in Alaska. The structure of the West Coast market itself has undergone dramatic transformation over the past several years as refiners have merged and consolidated into fewer companies. And as ANS production has declined, West Coast refiners, that until recently benefited from a surplus of ANS production relative to refining demand, have had to import large quantities of foreign crude oil again. This recent change has brought a renewed emphasis on long-term relationships again at the expense of spot transactions. It also has brought about direct competition between ANS crude oil and foreign crude oils imported into the West Coast.

Implications of Oil Royalty Experience for Gas Royalty Determination

As these changing market environments illustrate, even the best-conceived royalty valuation formula can go astray over time unless it adapts to new conditions. This in fact has happened periodically during the past decade that the royalty settlement agreements have been in place. The agreements have been modified several times. Each of these was occasioned by a recognition that market conditions had changed substantially enough to change the nature of the bargain originally agreed to.

This history of ANS oil royalties highlights both the need to maintain flexibility in the procedures and mechanisms used to value and pay gas and NGL royalties and, more importantly, the critical need for information sharing between producers and the State as to how ANS gas and NGL is moved to market and sold. As discussed in Chapter 3, producers of ANS gas and NGL face a number of difficult marketing and transportation choices with respect to gas and NGL. How they solve those in a way that maximizes their own value will no doubt require experimentation with various marketing and transport options. While ANS producers and the North American markets that they sell into adjust to the new volumes and settle into a balanced, consistent flow of gas and NGL to sales markets, information as to actual dispositions will be vital both to producers and to the State in understanding how ANS gas and NGL value can be maximized.

Chapter 6

Conclusions

This Report has provided an overview of gas and NGL markets in North America as they are structured and operate today, with observations as to how those markets can be expected to perform in years to come. In addition, we have described and analyzed market factors that are likely to determine the value of ANS gas and NGL when these begin to flow to North American markets within the next several years, and economic considerations relevant to structuring and applying royalty principles, methods, and procedures to best accommodate the State's interests as lessor of that gas and NGL. This Chapter draws these findings together in summary form.

Gas and NGL Markets in North America

1. North American gas markets have become flexible and responsive to supply and demand conditions, and are likely to remain so in years to come. Gas flows and prices respond to localized supply and demand conditions and pipeline capacity constraints or surpluses. Producers, marketers and end-users utilize the extensive pipeline network, along with storage facilities, market centers and financial instruments to consume and produce gas efficiently and to capture value when and where it arises.
2. Gas consumption in North America is expected to exceed 30 Tcf per year within the next 10 to 20 years. To accommodate that demand growth, producers not only must replace today's depleting wells, they must find and develop new reserves. Alaska gas will be one of those new supply sources. Substantial infrastructure – pipelines, storage, hubs – must be built to move new-found reserves to markets.
3. Based upon historical trends, gas and NGL prices – always a hazard to forecast – are unlikely to rise substantially, except for periodic spikes at various times and at various locations in response to temporary conditions.
4. NGL markets in North America are not as commoditized as gas markets. There are fewer active trading points, and the transport network, less extensive than that for gas, does not for the most part operate as a displacement network. That reduces opportunities to exploit logistic and financial efficiencies that are present for gas.
5. NGL finished product prices are established at a handful of market centers. Upstream raw-mix prices are set by reference to market center prices, less deductions for transport and fractionation costs.
6. NGL finished product prices are buffeted by numerous and diverse influences including oil and gas prices, petrochemical demand, heating fuel demand, and oil refinery output. The family of NGL finished products – ethane, propane, butane, and others – are each subject to distinct market forces. Wellhead NGL is a mixture of these finished products and therefore its value is affected to some degree by each distinct factor in addition to locational factors, transportation costs and fractionation costs.
7. NGL markets are likely to operate in the future much as they do today – largely the domain of a comparatively small group of specialists. Raw-mix NGL prices will continue to be set by downstream product prices (published and available for select locations) less transportation and fractionation cost deductions (limited reliable public information).

ANS Gas and NGL Value

1. Alaska gas most likely will enter the North American market at Alberta, Canada or at consuming markets downstream of Alberta. Alberta is a large "node" on the North American gas grid, but one which to date has been subject to periodic price fluctuations owing to imbalanced development of gas production and takeaway pipeline capacity.
2. Alaska wellhead gas value will be set by conditions in North American markets and by transport costs from the North Slope of Alaska to those markets. Even should in-state markets develop substantially, the bulk of produced volumes will flow to out-of-state markets.
3. Alaska NGL also is likely to enter North American NGL markets at Alberta, which is a major NGL trading center in North America.
4. Alaska gas and NGL are likely to be transported to Alberta in the same pipeline. While that may be the least cost method to move ANS gas and NGL, it complicates determination of transport costs for both gas and NGL. Transport cost is an important component in determining the wellhead value of both products.
5. The time horizon over which ANS gas and NGL will be produced is long – 50 years or more. It is not possible now to predict fully how North American gas and NGL markets will change over that time period, or to predict the evolving role of Alberta within the North American gas grid and in its role as a major NGL and petrochemical center. These will be the major factors to understand and factor into ongoing ANS value determination. Only time and experience can reveal the specific consumption markets to which ANS gas will flow downstream of Alberta.

ANS Gas and NGL Royalty

1. Efficient and workable royalty agreements should specify principles, methodologies and procedures to be used by lessor and lessee as they share production or revenues. In addition, there should be a well-understood and readily-identifiable mechanism that tells the parties when to modify existing methodologies or procedures (or change to entirely new ones) in order to remain faithful to their initial sharing principles.
2. The State's experience with oil royalty provides a useful template for gas and NGL royalty. Lessons learned and expertise developed there can be applied to gas and NGL royalty. In particular, the basic approach taken for oil – to gather and analyze information as to actual proceeds, then construct value measures from that information – should serve the State and producers well for gas and NGL royalty.
3. Because the role of ANS gas in North American markets for the next 50 years cannot be predicted today, the parties should provide sufficient royalty flexibility to adapt methods and procedures as conditions warrant. Within that framework though, there is room for agreement now as to first principles of production and/or revenue sharing, but these should not be carried to the point of eliminating adaptability.
4. Information is a primary source of royalty problems, even for mature production at or near major markets. ANS gas, at least in the early years of its production, and probably for much longer than that, enjoys neither of those characteristics. Information sharing therefore takes on heightened importance for ANS gas and NGL royalty. This suggests that the State and producers may both be well served to put in place a mechanism at the

outset of production for generating and sharing information that is above and beyond that which might be called for in mature areas.

5. The information so shared should relate to the actual sale of ANS gas and NGL as well as actual transport and processing costs incurred. Agreement should be reached as to measures of such revenues and costs that accurately track ANS gas and NGL flows and transactions from points of production to points of sale. The State should be allowed to utilize source documents and data in order to apply and test the effects of alternative revenue and cost allocations where commingling of gas makes such allocation necessary.

6. Information from such a mechanism will guide the State and producers in understanding how ANS gas and NGL fits into North American markets. It is likely to take some time for market dynamics there to adjust fully to introduction of ANS gas and NGL. The heightened information sharing period should last until markets have digested ANS volumes and an adequate understanding is reached as to how and where ANS volumes are sold and priced.

7. When that level of understanding is achieved, it may be possible then to turn to mechanisms that utilize published market information and are less costly to implement, such as use of downstream market price indicators and market-based transport and processing cost indicators.

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ALASKA HIGHWAY NATURAL GAS POLICY COUNCIL

REPORT TO THE GOVERNOR

VOLUME ONE

NOVEMBER 30, 2001

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Alaska Highway Natural Gas Policy Council

Report to the Governor

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Note to Readers: This is Volume I of the Alaska Highway Natural Gas Policy Council Report to the Governor. Volume II includes public testimony, selected presentations, and subcommittee meeting summaries. For copies of Volume II, please contact the Governor's Office at (907) 269-7450.

Section I:

Council Background

ADMINISTRATIVE ORDER NO. 188

I, Tony Knowles, Governor of the State of Alaska, under the authority of art. III, secs. 1 and 24 of the Alaska Constitution, establish the Governor's Alaska Highway Natural Gas Policy Council (Council).

PURPOSE

1. Alaska North Slope gas development and transportation to market is of vital public interest. It is in the best interest of the people of Alaska that a North Slope natural gas commercialization project advance, to the maximum extent allowed by law, Alaska hire and use of Alaska businesses; Alaskan access to gas; and a fair share of revenues for Alaskans. This project should improve the standard of living for Alaskans by providing feedstock for new industries, community access to gas, and gas for future commercialization projects that may become feasible as market conditions improve. It is essential that Alaskans have a voice in determining how the state will achieve these goals.

2. As Governor, I join the many Alaskans in believing that the only viable and environmentally responsible project is a natural gas pipeline from Prudhoe Bay to Fairbanks, and then along the Alaska Highway through the Yukon Territory and Alberta to connect with distribution systems in America. This route was approved by Congress in 1977 and is the subject of an international treaty with Canada.

3. The purpose of the Council is to engage Alaskans representing a broad spectrum of Alaska interests, experience, and geography to advise the Governor and the Alaska Highway Gas Pipeline Cabinet in determining how the state can best promote the Alaska Highway North Slope natural gas pipeline project and maximize benefits for Alaskans.

DUTIES

1. The Council shall hold statewide meetings to obtain the public's views on how the state can best promote a gas commercialization project and maximize benefits for Alaskans. During

the meetings, the Council shall present a summary of project options and general topics for discussion.

2. Before the statewide meetings, the Council shall meet to plan its work schedule and prepare the presentation for the meetings.

3. No later than November 30, 2001, the Council shall present a summary of public comments, consensus recommendations, and other information gathered to the Governor, the Alaska Highway Gas Pipeline Cabinet, and the public.

4. The Council shall deliberate and make recommendations on topics related to natural gas commercialization, including

   a. the benefits of natural gas development to Alaska communities, including those located in rural areas of Alaska;

   b. the best uses of the state's royalty share of the gas and promotion or attraction of investment for in-state and value-added processing;

   c. the costs and benefits of the state taking delivery of its royalty share of the gas in Alaska versus allowing a project developer to include the gas in its delivery flow to the lower 48 states;

   d. options for projects utilizing gas-to-liquids, liquified natural gas, and natural gas liquids;

   e. demand for in-state natural gas consumption and its effects on a gas project;

   f. environmental impacts and necessary protection measures;

   g. training and readiness of Alaskans for jobs on a gas project, use of the Alaska labor pool by contractors and subcontractors, and use of Alaska businesses; and

   h. state promotion and facilitation of project financing, including potential ownership by the state of some or all of a project.

MEMBERSHIP AND GENERAL PROVISIONS

The Council shall be comprised of Alaskans representing a diversity of interests, experience, and geography and appointed by the Governor to serve at the pleasure of the Governor. Members of the Alaska Highway Gas Pipeline Cabinet shall serve as non-voting, ex-officio members of the Council.

The Office of the Governor and other state agencies shall provide professional and administrative staff assistance to support the activities of the Council. The Department of Law shall provide legal assistance to the Council.

To reduce costs, the Council shall use teleconferencing or other electronic means to the extent practicable in order to gain the widest public participation at minimum cost.

The Council shall establish procedures for voting and meetings. Council members who are not state employees serve without compensation and are entitled to per diem and travel expenses in the same manner permitted for members of other state boards and commissions. Per diem and travel expenses for members of the Council who are appointed as a member of a state agency are the responsibility of that state agency. The Governor shall designate two members of the Council as co-chairs. Meetings of the Council shall be conducted and notices of such meetings provided in accordance with AS 44.62.310 (Open Meetings Law).

AMENDMENTS AND REVOCATIONS

This Order amends Administrative Order No. 187 to change the name of the Gas Pipelines Cabinet to the Alaska Highway Gas Pipeline Cabinet.

This Order revokes Administrative Order 152.

This Order takes effect immediately.

DATED at ____________________, Alaska, this ____ day of January, 2001.

____

Tony Knowles
Governor

FOR IMMEDIATE RELEASE: January 26, 2001 01-027

KNOWLES ANNOUNCES CO-CHAIRS OF NEW ALASKA HIGHWAY NATURAL GAS POLICY COUNCIL

Prominent Alaskans to Help State Direction on Gas Development; International Energy Firm to Advise State and Alaskans

ANCHORAGE—Continuing his push to develop an Alaska Highway natural gas pipeline, Gov. Tony Knowles today announced two initiatives to further commercialization of Alaska's North Slope gas. By state Administrative Order, the governor created the Governor's Alaska Highway Natural Gas Policy Council to be chaired by two prominent Alaskans – retired ARCO Alaska Senior Vice President Frank Brown of Anchorage and former Fairbanks North Star Borough Mayor Jim Sampson of Fairbanks.

Knowles also announced that his administration has contracted with one of the world's top international oil and gas experts, Cambridge Energy Research Associates, to provide Alaskans expertise and analyses of various aspects of gas development.

"When it comes to natural gas, after two decades of false starts and broken dreams, the economic and political stars are finally aligned in Alaska's favor," Knowles said. "Despite our distance from domestic markets, our natural gas is more economic now than ever. The Governor's Alaska Highway Natural Gas Policy Council will engage the public as it analyzes the many issues related to gas development and makes recommendations to Alaskans."

The governor asked the council to begin its work soon and report back with recommendations by November 30, so their work can be incorporated into gas line legislation and project development. Knowles noted that his new special assistant for economic development, Ken Freeman, will provide staff assistance to the council.

Cambridge Energy also will assist the council and Alaskans in analyzing the many aspects of gas development. "Led by Pulitzer Prize-winner author Daniel Yergin, who won the honor for his thorough history of world oil development, Cambridge Energy can provide the objective market analysis we need to make the important public policy decisions facing Alaska," Knowles said.

The governor also used his remarks to the Alliance to praise developments in the oil patch.

Citing a recent analysis of the impact of the oil industry on Alaska's economy, Knowles noted that more than one in ten private sector jobs in the state are the result of this industry, which also has the highest average wage and the largest private sector payroll in Alaska. The investment the oil and gas industry makes in Alaska each year is roughly equal to the state's annual general fund spending.

"Alaska's major producers, especially BP and Phillips, are working hard to keep those good news numbers coming by aggressively exploring for oil and gas on the North Slope," he said. "By investing about 25 percent more in capital spending, Phillips has targeted a 14 percent oil production increase over the next 5 years; BP 17 percent.

> "Other companies such as Alberta Energy, Unocal, Marathon and others, are equally bullish on the Slope and in Cook Inlet. Last fall's North Slope area-wide sale set a record for state oil and gas lands leased for exploration, more than 713,000 acres," Knowles said. "In Cook Inlet, there's a renewed interest in exploration of natural gas and Forest Oil set the first new platform in Cook Inlet since 1986. The state is responding to all this interest with 16 area-wide lease sales in the next 5 years."

After Alaska's success in convincing the national administration to open the National Petroleum Reserve-Alaska to oil and gas exploration, Knowles said the challenge now is to persuade America and Congress to permit environmentally responsible development in the Arctic National Wildlife Refuge.

"We breathed a sigh of relief when the Clinton administration listened to Alaskans and declined to make ANWR a national monument," he said. "With a new national administration, we're better positioned for success in ANWR. But we shouldn't kid ourselves into believing we face a cakewalk.

"Our challenge is to demonstrate, using the latest technology and relying on the world's safest oil transportation system, that we can develop the oil beneath the refuge, while protecting the environment and fish and wildlife that we value so much and which are such an important symbol for so many Americans," the governor said.

Knowles has taken a number of steps to advance gas development, including visiting personally with the top officials of Alaska's oil and gas producing companies. He co-sponsored a natural gas summit in Columbus, Ohio attended by experts from more than 40 states.

Two weeks ago, he signed Administrative Order 187 creating a special Natural Gas Pipeline Cabinet and directing state agencies to work aggressively for timely one-stop permitting and right-of-way preparation. The Knowles administration has introduced legislation extending the state's ability to negotiate tax flexibility for natural gas projects, like an Alaska Highway gas line.

These initiatives are supported by a multi-million dollar budget request, which Knowles has asked the Legislature to act on quickly.

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FOR IMMEDIATE RELEASE: February 2, 2001 *01-035*

KNOWLES ADVANCES ALASKA HIGHWAY GASLINE WITH POLICY COUNCIL
Civic, Business Leaders Included in 28-Member Panel

Citing their breadth of experience and leadership in keeping Alaska's economy healthy, Gov. Tony Knowles today announced 26 members of the Governor's Alaska Highway Natural Gas Policy Council. The council will spend the next 10 months focusing on the best ways to advance construction of a natural gas pipeline down the Alaska Highway.

"This council is one of the smartest, most experienced, and highly dedicated group of Alaskans ever assembled for a single purpose: to help guide Alaska public policy as we build a natural gas pipeline," Knowles said. "I'm honored each of these Alaskans answered my call to public service for this important effort. I know Alaskans will be reassured that their views about this enormous project will be considered."

Knowles created the council January 26, when he signed an administrative order to "engage Alaskans representing a broad spectrum of Alaska interests, experience, and geography to advise the Governor and the Alaska Highway Gas Pipeline Cabinet in determining how the state can best promote the Alaska Highway North Slope natural gas pipeline project and maximize benefits for Alaskans."

The Governor last Friday announced the council's two co-chairmen: retired ARCO Alaska Senior Vice President Frank Brown of Anchorage and Jim Sampson, Executive Director of the AFL-CIO in Alaska and a former mayor of the Fairbanks North Star Borough. The 26 other members of the council appointed by the Governor today include:

- Former state representative and Kenai Peninsula Borough Mayor Mike Navarre;
- Anchorage Mayor George Wuerch;
- Former state Attorney General Grace Schaible of Fairbanks;
- Bill Corbus, president of Alaska Electric Light and Power Company of Juneau;
- Former state Attorney General Charlie Cole of Fairbanks;
- Former state Senator Al Adams of Kotzebue;
- Carl Marrs, president and CEO of Cook Inlet Region, Inc., of Anchorage;
- Rosemarie Maher, president and CEO of Doyon, Ltd., of Fairbanks;
- Former state Natural Resources Commissioner Esther Wunnicke of Anchorage and a member of the public policy group Alaska Common Ground;
- Former Anchorage Mayor Jack Roderick, a noted Alaska author and oil industry historian;
- Oil and gas consultant Brian Davies of Anchorage and former vice president for BP in Alaska;
- Jim Jansen, President of Lynden transportation company in Anchorage;
- Former Permanent Fund Executive Director Dave Rose, currently president of Alaska Permanent Capital Management;
- Ed Rasmuson, chairman of the National Bank of Alaska;
- Lee Gorsuch, chancellor of the Universi Alaska Anchorage;
- Anchorage businessman Bob Penney, a member of the North Pacific Fisheries Management Council;
- Fairbanks North Star Borough Mayor Rhonda Boyles;
- Ron Duncan, president of GCI;
- Former ARCO Alaska President Ken Thompson, currently CEO of Pacific Rim Leadership Development of Anchorage;
- Peg Tileston of Anchorage, an environmental citizen activist and board chair of Alaska Common Ground, a non-partisan public policy group;
- Jake Adams, president of the Arctic Slope Regional Corporation
- North Slope Borough Mayor George Ahmaogak,

- Anchorage attorney Jeff Feldman;
- Jon Rubini, an Anchorage real estate businessman with statewide investments;
- Jerry Hood, chief executive officer of Alaska Teamsters Union local 959; and
- Mike O'Connor, president of Peak Oil Field Services Company.

"Commercialization of North Slope natural gas via the gasline project is the biggest economic opportunity to come to Alaska in years," Knowles said. "Taking full advantage of this opportunity won't be easy, though, and that's why we need a broad based, diverse group of Alaskans to work through the many issues that have to be addressed. I'm confident that this group will ensue public participation and produce recommendations that will protect the public's interests and make Alaskans proud as the gasline moves forward."

The Governor asked the council to hold statewide meetings to obtain the views of Alaskans on how the state can best promote a gas commercialization project and maximize benefits for Alaskans. He asked it to report back with recommendations by November 30, so their work can be incorporated into gas line legislation and project development. Among the issues the council will consider are:

- Benefits of natural gas development to Alaska communities, including those located in rural areas of Alaska;
- Best uses of the state's royalty share of the gas and promotion or attraction of investment for in-state and value-added processing;
- Costs and benefits of the state taking delivery of its royalty share of the gas in Alaska versus allowing a project developer to include the gas in its delivery flow to the Lower 48 states;
- Options for projects utilizing gas-to-liquids, liquified natural gas, and natural gas liquids;
- Demand for in-state natural gas consumption and its effects on a gas project;
- Environmental impacts and necessary protection measures;
- Training and readiness of Alaskans for jobs on a gas project, use of the Alaska labor pool by contractors and subcontractors, and use of Alaska businesses; and
- State promotion and facilitation of project financing, including potential ownership by the state of some or all of a project.

Two weeks ago, Knowles signed an administrative order that created a special Alaska Highway Natural Gas Pipeline Cabinet and directing state agencies to work aggressively for timely one-stop permitting and right-of-way preparation. Members of the Gas Pipeline Cabinet will serve as ex officio members of the council.

Knowles also recently introduced legislation that amends the "stranded gas" legislation that was passed in 1998 to facilitate natural gas commercialization to include an Alaska Highway natural gas pipeline or a gas-to-liquids (GTL) project.

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Alaska Highway Natural Gas Policy Council

COMMITTEE STRUCTURE

Council Mission: To promote an Alaska Highway Natural Gas Pipeline project to the lower 48 that also enables creation of a natural gas business in Alaska.

Alaska Hire/Buy/Build – Mike Navarre, chair
Jerry Hood, Rhonda Boyles, Jake Adams, Peg Tileston

- Use of the Alaska labor pool by contractors and subcontractors
- Use of Alaska businesses
- Training and readiness of Alaskans for jobs on a gas project
- Socio-economic impacts

State Pipeline Ownership and Tax Structure – Bill Corbus, chair
Dave Rose, Ron Duncan, Grace Schaible, Mike Navarre, Ed Rasmuson, Mike O'Connor, Ken Thompson

- State promotion and facilitation of project financing – state ownership
- Evaluation of state tax structure

Federal/International Action – Charlie Cole, chair
Esther Wunnicke, Bob Penney, Jon Rubini, Jeff Feldman, George Wuerch

- Federal permitting/access
- Federal agency lead
- Canadian permitting/access
- Other contractual considerations
- Domestic markets – competing sources/sharing of the market
- Canadian national and territorial relations

Access for In-State Gas Use and Future Opportunities – Ken Thompson, chair
Carl Marrs (vice chair), Rhonda Boyles, Al Adams, Brian Davies, Jim Jansen, Jerry Hood, Bob Penney, Jack Roderick, Lee Gorsuch, Jeff Feldman, George Ahmaogak, Bill Corbus

- Supply/demand for in-state natural gas
- Best practices valuation/netback pricing methodology to facilitate in-state gas use
- Ensuring fair and transparent access rules to natural gas for Alaskan customers
- Benefits of natural gas development to rural Alaska and to communities along the pipeline
- Future options over 50 years for projects utilizing: gas-to-liquids (GTLs), liquefied natural gas (LNG), natural gas liquids (NGLs), petrochemical feedstock, fertilizer, etc. for in-state use or for export to markets in Asia or the West Coast
- Promotion or attraction of investment for in-state distribution and value-added processing
- Assess costs and benefits of the State taking delivery of its royalty share vs. taking royalty payments; review other states' policies for best practices

Environmental Considerations – Peg Tileston, chair
Brian Davies, Esther Wunnicke, Lee Gorsuch, Grace Schaible

- Environmental impacts and necessary protection measures
- Doing it right

Section II:

Subcommittee Reports

Alaska Highway Natural Gas Policy Council

Committee Report
Alaska Hire/Buy/Build Committee
Mike Navarre, Chair

Recommendation:
The committee believes Alaska residents and contractors should be employed on a gasline project when they are available and qualified. In turn, contractors should be encouraged to employ and train Alaska residents.

Recommendation:
The committee believes that Alaska hire language, similar to language from the BP/ARCO Merger "Charter Commitment," should be sought for the Alaska Highway natural gas pipeline and facilities. *(Note: charter language is attached.)* It should be specifically stated that the quarterly report to the Department of Labor should include all contractors and subcontractors of the company or sponsor.

Recommendation:
The committee believes additional funding should be made available for vocational education training and should be coordinated with existing workforce training efforts now underway. Additionally, efforts should be increased to notify interested Alaskans of training opportunities available.

Recommendation:
The committee believes every effort should be made to ensure that needed gas production facilities are constructed at sites in Alaska.

Recommendation:
The committee recommends the State's Department of Community and Economic Development undertake a study to determine the socio-economic impacts of the gas pipeline along the Alaska Highway route. The Department has already begun implementation of this recommendation. A draft "scope of work" for this study is attached. We recommend the scope of the study also be expanded to include impacts to local governments.

Conclusions and narrative:
The committee held several hearings regarding the constitutionality of local hire laws. The record in Alaska on local hire litigation is not encouraging. We believe it will be difficult to construct local hire legislation that will withstand challenges under the U.S. and Alaska Constitutions (equal protection and privileges and immunities clauses). Additionally, a successful Alaska hire provision is complicated by the national and international scope of the project. Voluntary, cooperative efforts with industry seem to hold the most promise and should be pursued.

The number of jobs will be significant and will exceed the available capacity of Alaskan workers. The committee heard testimony that there is already a crisis situation being created because of the aging workforce in the oil industry, without factoring in the effect of a large-scale project like the gasline. There are coordinated efforts already underway, by industry, unions, native and tribal organizations, the Denali Commission, the University of Alaska and state agencies to address the training of Alaskan workers, and those efforts will require additional funding. The Alaska Human Resources Investment Council has developed a white paper that details a comprehensive approach to workforce training. It is attached as part of this report.

In addition to assuring labor stability, a project labor agreement will facilitate the further ramping up of union training programs, bringing more Alaskans into apprenticeship and skill upgrade programs. An ancillary benefit of the PLA is the legality of geographic preference provisions of collective bargaining agreements.

Committee members heard testimony from rural residents along the pipeline route expressing interest in job opportunities. We believe that issue is best addressed through notification, to interested Alaskans, of available training and through registering of interested workers and their skills. Construction training in rural Alaska has increased to an unprecedented level in the past two years through initiatives such as the Alaska Works Partnership, various labor organization programs, and the Denali Training Fund and other efforts funded by the Denali Commission. Continued support of these initiatives, which have resulted in training and employment of hundreds of rural Alaskans in construction, is essential if residents of communities along the pipeline and in areas of the state suffering economic dislocation due to fisheries problems, are to share in the economic benefits of the project. The Department of Community and Economic Development is already working with Native nonprofits to create accurate job banks, focusing on rural areas and villages.

The committee also obtained information regarding module related jobs for gas treatment facilities and compressors. The opportunity is tremendous and construction of modules, at Alaskan sites, should be vigorously pursued. It is estimated that the module related jobs and opportunities will be bigger than the Alpine, Northstar, Badami and MIX projects combined.

ALASKA HIRE COMMITMENT LANGUAGE
from BP/ARCO "Charter for Development of the Alaskan North Slope"
December 2, 1999

1. Alaska Hire Program.
BP and ARCO agree that, after the merger is completed, they will continue with and extend their commitment to the people of Alaska to utilize a voluntary program to employ residents of Alaska and to use Alaska businesses. It is expected by the parties that this program will include the attributes that:

a. BP and ARCO will comply with all valid federal, State and local hiring laws in hiring Alaska residents and contractors and will not discriminate against Alaska residents or contractors, and within the constraints of law will employ Alaska residents and contractors to the extent they are available and qualified;
b. When recruiting for new hires, BP and ARCO will advertise for available positions locally and use Alaska job service organizations to notify the Alaskan public;
c. BP and ARCO will use best efforts to contract with Alaska firms and fabricate modules in Alaska whenever feasible (in determining feasibility, BP and ARCO will consider commercial, health, safety, and environmental conditions and requirements to ensure maintenance of BP and ARCO's operational standards); and
d. BP and ARCO will, to the extent permitted by law, encourage its contractors to employ, and train when necessary, residents of Alaska.

2. Reporting.
BP and ARCO agree to submit to the Director, Division of Oil and Gas, for transmission to the Department of Labor, an annual report that details the specific measures that they and their contractors and subcontractors have taken or are planning to take to recruit qualified Alaska residents for available jobs, describes on-the-job training opportunities, and describes their efforts to use Alaska businesses for work in connection with their leases and associated activities. BP and ARCO will also furnish the Department of Labor a quarterly report regarding their employment of Alaska residents. The report will include statistical data concerning the number of resident personnel hired within the previous year.

3. Construction.
The program and reporting described in this paragraph are intended to be fully consistent with the 1996 amendments to paragraphs 41 (1980 leases) and 31 (1983 lease) of the Northstar Unit leases between the State and BP.

4. Alaska Native Recruitment, Training and Hire.
BP and ARCO further acknowledge their continuing support for the recruiting, training and hiring of Alaska Natives and the parties' common understanding of the desirability of providing Alaska's first citizens opportunities to participate in the economic benefits of oil and gas development, most of which takes place in rural Alaska.

Department of Community and Economic Development
Alaska Gas Pipeline Socio-Economic Impact Study
Scope of Work (DRAFT)

The Department of Community and Economic Development is currently undertaking a study to determine the socio and economic impact of the gas pipeline along the Alaska Highway route. There are currently two segments of the report. In order for the State of Alaska to anticipate future needs arising from the gas pipeline project, it will be necessary to look at both the positive and negative impacts associated with the construction and the operation.

Segment 1
The first segment is an analysis of the impacts to state departments (specifically DCED, DHSS, DNR, DOL, DPS, DOE). The Department is currently investigating this section internally. After completing a preliminary analysis of potential impacts to state agencies, the report will be disseminated amongst the agencies so that the departments can tailor more specific questions that will need to be addressed.

Segment 2
The second segment is the potential economic benefits the gas pipeline would have for the State of Alaska and perhaps in more detail the communities along the proposed Alaska Highway route. An independent third party contractor will investigate this segment.

It would identify potential economic opportunities created by the gas pipeline along the highway route during construction and also during the operational phase. For the construction phase, the study would examine past pipeline projects to see which sectors benefited from the construction activities as well as what types of business developed in the region during the construction phase.

The study would also include an analysis of what types of businesses might expand or relocate to Alaska as a result of accessibility to a large supply of natural gas. These projects might include a petrochemical facility, an increase in mining activity, and transportation infrastructure. Other benefits that could be examined include the potential for cheaper utilities to rural areas as well as an increase to the local tax base for communities along the pipeline.

Once the scope of work can be finalized, an RFP will be created based on the finalized scope of work.

DRAFT

Alaska's Skilled Worker Shortage: Crisis or Opportunity?

A White Paper for the
Alaska Human Resource Investment Council

August 9, 2001

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Introduction

> The future looks bright for Alaska, but do we have the people to fill the jobs? The oil and gas industry wants to fill positions to support a new gasline. Will those employees come from out of state? They'll have to if we don't have a trained workforce in Alaska to fill the good jobs. The same goes for teachers, pilots, nurses, truck drivers. Our only hope is training. But no one entity can do it alone. Industry must partner with education. Unions must work with vocational schools. Partnerships, incentives and education are the key.—*Lt. Governor Fran Ulmer*

Over the last two years the Alaska Human Resource Investment Council (AHRIC) has become increasingly concerned about the lack of a skilled workforce in Alaska. Members of the AHRIC believe the state is on the verge of a workforce crisis, describing the situation as "urgent," "serious," and "critical." But members of the AHRIC also believe the labor shortage presents tremendous opportunities for Alaskans who are unemployed or who lack education and training. As the "...private/public leadership board that sets the policy framework for developing Alaska's workforce," members of the AHRIC call attention to Alaska's workforce issues. Planning efforts today will have a direct impact on Alaska's ability to attract new businesses, maintain an educated workforce and build and sustain projects such as the much-desired natural gas pipeline.

Workforce Concerns

A natural gas pipeline from the North Slope to the lower 48 has become more of a reality with the rising price of petroleum products. A national missile defense project based in Alaska is being discussed in Congress. Commercial construction activity is healthy in Anchorage, with two multi-story office buildings under construction and a 23-story multi-use facility in the planning phase. Visions of an economic expansion are tempered, however, by the fact that Alaska may not be able to supply enough trained workers. A recent Associate Press article states:

> The oil patch is bustling around the country, so Alaska is competing with the Lower 48 states and elsewhere for engineers, pipefitters, drilling workers and more to find and develop new oil reservoirs.... *Allen Baker, The Associated Press, April 17, 2001*

In addition to the lack of skilled workers, many of Alaska's trained workforce are on the verge of retirement. Add to that predicament the fact that there has been a decline in the number of younger Alaskans:

> The number of Alaskans age 20 to 34 has declined significantly in total numbers (by about 36,000) since the 1990 census....Just as a disproportionately large number of Alaskans approach retirement age there will be relatively few Alaskans that will have completed postsecondary education or training needed to fill the openings created by retiring workers.
>
> —*Alaska Economic Trends, September 2000*

The oil and gas industry has one of the highest percentages of workers over the age of 50; in 1999 the average age of a pipeline worker was 47. In addition, the average age of electricians, operating engineers, institutional cooks, mechanics, heavy equipment mechanics, engineers, civil engineers, and workers in heavy construction is 40 or over.

The need for trained workers extends well beyond the construction trades. Like the rest of the nation, Alaska is desperate for health care and information technology workers. There is a shortage of teachers in rural areas of the state, especially Alaska Native teachers. With regard to employer demand, the health care industry has the highest need for workers; of the 15 fastest-growing occupations, ten are associated with health services, three with information technology and two with the transportation/ visitor industries.

In order to attract and keep businesses in Alaska, it is necessary to have good schools, a business-friendly environment and basic infrastructure. We can't have good schools without good teachers. A business-friendly environment is impossible without educated, trained workers. Basic infrastructure cannot be built without skilled labor. Alaska's workforce is the common denominator that makes economic development possible.

Defining Workforce Priorities

> We've been here before; we know what happened when Prudhoe Bay came online. We didn't have enough Alaskans to fill the jobs and we imported a lot of labor from Outside. Let's not revisit the past. We have an excellent opportunity to train Alaskans. Let's make sure Alaskans are the first to benefit from the next big project. — Ed Flanagan, Commissioner, Alaska Dept. of Labor and Workforce Development

The AHRIC has already laid the groundwork to prioritize Alaska's workforce development needs. In response to legislation passed during the 2000 legislative session, an annual priority list for Alaska Technical and Vocational Education Program grants was developed. The construction, health care, information technology and transportation industries have been targeted, based on economic, employment and other relevant data developed to maximize employment opportunities for participants. Federal and state training dollars will now be awarded in alignment with the priority list.

Opportunities & Workforce Gaps

The Alaska Department of Labor's Research and Analysis (R&A) Section has extensively researched employment needs in the state and has identified lists of "hot" and "best-bet" occupations. "Hot" occupations are jobs with a higher than average projected growth rate and a higher than average estimated wage, and "best-bet" occupations are those with good employment opportunities and good wages. The R&A Section's statistics show that twenty-seven of the forty-one "best bet" occupations require education or training of an associate's degree or higher. There are a number of "hot" occupations, however, that do not require university degrees. Research and Analysis notes:

> The labor trades and crafts occupations of electricians, plumbers, electrical powerline installers/repairers, excavating and loading machine operators, and operating engineers all combine growing employment numbers with estimated earnings in the highest earnings group. The often rigorous training required for these occupations is generally available 'on-the-job.'

In addition, state labor economist Neal Fried has seen a shift in the state's population. "It's a tighter labor market and there's more turnover. There are more people leaving the state than entering," Fried said. As a result, there are more opportunities in Alaska for young people and unemployed workers than in the recent past. "The markets have been very healthy and the opportunities have been extraordinary for Alaskans who try to take advantage of it. Kids have many more opportunities than in the past if they know what's out there," Fried said.

A Call to Action

Are there enough workers in Alaska to build a large construction project? Will Alaska seniors suffer because there are too few health care workers to care for them? Will Alaska children receive a substandard education because certified teachers cannot be recruited? Will opportunities to expand Alaska businesses vanish because there are no information technology workers?

At this point, the answers to such questions are unclear. Many pieces are in place for Alaska's successful transition to a trained, skilled workforce, but more remains to be done. Governor Knowles and Lt. Governor Ulmer have made workforce development a high priority as evidenced by the creation of the Alaska Human Resource Investment Council (AHRIC), the Governor's Jobs Cabinet and the increased funding for the FY 2002 education budget. U.S. Senator Ted Stevens expressed concern over Alaska's lack of focus on vocational education, and the AHRIC responded with a state plan for vocational training, "*Alaska's Future Workforce Strategic Policies and Investment Blueprint.*" Proposals for regional training centers in geographic hubs have been evaluated and may be funded through efforts by Senator Stevens. State industries and business groups have set up formal consortia with educational institutions to develop curricula and focus on workforce needs. The Department of Labor and Workforce Development has initiated an effort to actively promote its job training and employment services and has developed a partnership with the Denali Commission, an organization that also provides job training opportunities.

In spite of current efforts toward solving the workforce crisis, state policymakers continue to be concerned. What must be done to produce a viable workforce to ensure future economic development in Alaska?

- Financial Support. The State of Alaska must increase aid to academic and vocational educational programs. Economic development will not happen without a workforce that has access to good educational opportunities.

- Help Students Succeed. State student loans are readily available, but the cost of a college education has increased exponentially over the years. A student graduating from college or vocational school is immediately faced with loan payments on the level of a car or house payment. The state can do more to encourage students to pursue a higher education by providing financial incentives for job training and postsecondary education in priority occupation areas; incentives should be geared toward encouraging students to remain in Alaska upon completion of their training or degree. The state can also encourage student success by providing adequate funding for:
  - early childhood education;
  - career education awareness and linkages, K-14; and
  - distance delivery of education to rural areas.

- Vocational education is key to training the number of workers who will be needed for all types of construction projects. Associated General Contractor's Dick Cattanach expresses the concern well:

> This year there were 6,900 high school graduates [in Alaska]. Of those, 70 percent don't go to college.... When I went to high school, kids took shop, woodworking; we don't have that anymore. We don't seem to emphasize the vocational track anymore. We emphasize the college track and we ignore 70 percent of the kids who graduate. We're not doing nearly enough. Voc ed is an afterthought—we're not focusing on the future of our kids.—*Dick Cattanach, AGC*

If we want trained workers for the future, Alaska's legislators and other key policymakers must commit to funding vocational education programs at a level that reflects the huge number of students who will not go on to advanced education. We must focus on "the other 70 percent."

- Workforce Development Clearinghouse. Creation of a web-based clearinghouse is necessary to provide access to essential functions of the workforce development system. Information is currently available through federal, state and local sources, but a central hub is necessary to manage information in a coordinated manner. The clearinghouse would include information regarding:
  - employment, training and labor market information;
  - professional development, technical assistance and capacity-building services;
  - budget review that promotes alignment and leveraging of resources.

- Reauthorization of the State Training & Employment Program (STEP) as a permanent program. STEP is an innovative job-training program created in 1988 and funded by one tenth of one percent of employee contributions to the Unemployment Insurance (UI) Trust Fund (no state general funds are used). STEP's purpose is to reduce current and future claims against UI benefits by training residents who are unemployed, underemployed or are about to lose their job. Although STEP has been reauthorized each time it has come up for sunset review, making STEP a permanent program in 2002 would signal a commitment by state leaders to train workers who might otherwise join the unemployment rolls.

- Strengthen and Secure AHRIC's Oversight Role. The Alaska Human Resource Investment Council has made significant strides in its first six years, but the AHRIC's oversight role must be strengthened to bring all Alaska education and training providers and workforce programs under one umbrella. The AHRIC is the oversight body that can make sure Alaskans are being trained for the right jobs and are meeting the needs of Alaska employers.

A Shared Vision

Alaska will have enough workers to build a pipeline, Alaska's seniors will be cared for, our children will receive an excellent education and business opportunities will abound if business, industry, government, the university and state policy makers join forces to make workforce development a top priority. We must plan now for tomorrow's workforce. If we fail to act, the opportunities we see on the horizon will become tomorrow's workforce crisis.

Alaska Highway Natural Gas Policy Council

Committee Report
State Pipeline Ownership and Tax Structure Committee
Bill Corbus, Chair

Recommendation:
The committee believes the pipeline is economically feasible for certain investors and should be undertaken with private financing. We recommend against direct State investment unless there is clear evidence of economic benefits to Alaska that cannot be achieved through other regulatory or political mechanisms.

Recommendation:
The committee encourages exploration of creative financial structures to facilitate all or part of a gas pipeline and/or in-state gas infrastructure, provided such entities finance their activities through private markets.

Recommendation:
The committee recognizes that State tax policy is one of several tools that could play a role in influencing pipeline development, but reserves a decision. It is premature to decide how to use this tool until there is more definition of a project and the nature of its ownership.

Conclusions:
* When the committee began its work early in 2001, there appeared to be certain problems that could be resolved by partial State ownership in a gas pipeline, and that it could be an important advantage for Alaska. However, through the process of gathering information and holding meetings, the committee has determined that most if not all of these could be resolved through other means, other tools the State has at its disposal. For example, access to and from a pipeline can be facilitated through the State Regulatory Commission of Alaska working with the Federal Energy Regulatory Commission, and through stipulations in a State right-of-way lease across state lands.

* The committee believes a natural gas pipeline from Alaska would be a good investment, but there are other, equally good investment opportunities for public funds that entail less risk. The State has a policy of diversifying investment of its assets (the Permanent Fund is an example) to reduce risk.

* From information gathered during hearings, the committee has concluded that, absent majority or total ownership of a natural gas pipeline, an ownership interest gives the State no right to capacity in the pipeline. Capacity in a contract carrier pipeline is obtained through the nomination process during an "open season."

* The committee is not persuaded that partial ownership of the pipeline raises any conflict of interests for the State (i.e. a State "ownership" interest vs. a State responsibility to regulate the pipeline) that cannot be resolved.

* The committee investigated alternative sources of financing, including the Permanent Fund, Constitutional Budget Reserve and the ability of various public authorities to issue revenue bonds. The committee believes that private sector companies can raise needed funds based on adequate coverage and financing reserves. State participation would not enhance the acquisition of funds, would not necessarily guarantee lower financing costs and might unduly interfere with a straightforward private sector funding. The State's participation would include a vote on a tariff, but its interest would not be proportionately large and it would not guarantee a desired outcome.

* Absent a compelling public interest for partial State ownership, ownership of the pipeline is best left to private industry and to firms which are experienced in oil and gas and the pipeline business.

* The committee suggests that Alaskan-owned businesses, such as Alaska Native corporations, have the opportunity to invest in a natural gas pipeline project.

* Regarding alternative financing mechanisms, the committee has been told by the producers' group that an investment in a gas pipeline might not meet the rate-of-return criteria for the producing companies. If so, alternative financing mechanisms, such as through a public authority, might facilitate others, such as pipeline transmission companies, becoming involved. A public authority may have advantages in terms of exemption from federal income tax, or jurisdiction by the Federal Energy Regulatory Commission.

* Regarding tax policy, the producers are seeking simplification and clarity in natural gas tax and royalty administration.

* The Gas Policy Council itself has endorsed the Governor's proposals for federal tax incentives, such as accelerated depreciation, an investment tax credit and a gas price volatility protection mechanism, a tax credit that becomes effective if prices fall below a certain point. The committee reaffirms this endorsement.

* The committee feels that if a viable proposal for a pipeline is put forward and the producers do not respond in a reasonable period of time, the State should use the tools that it has available to facilitate the project moving forward.

* The committee recommends finding a mechanism for a "contract" between the State and a sponsor of a gas pipeline project that would encourage a State fiscal policy as well as a stable State revenue policy. While there are legal limits to the Legislature's ability to guarantee future tax policy, such a contract would carry an important moral commitment and would be worthy of consideration for an Alaska Highway gas pipeline.

* Different forms of pipeline ownership will affect the interests, and incentives, of the parties involved. Overall, the State has an interest in keeping costs of a pipeline down, and transportation tariffs lower, to maximize State revenues. (State revenues are based on the "wellhead" values of gas on the North Slope, after transportation.) If the producers build the pipeline, they will have an interest in maximizing production revenues, similar to the State, but will have less interest in keeping tariffs low because they are also pipeline owners. If an independent pipeline company consortium owns the pipeline, the producers' interests will be only in maximizing production revenues. In that scenario, the producers' interests would be aligned with the State's in seeking low tariffs for transportation of gas.

Alaska Highway Natural Gas Policy Council

Committee Report
Federal/International Action Committee
<u>Charlie Cole, Chair</u>

Introduction

Members of the Gas Policy Council were extensively involved in decisions on State policy and in the development of proposed legislative changes. A substantial product of the Federal/International Action Committee were recommendations for changes to federal law to address key concerns of the State of Alaska in the development of a natural gas pipeline.

The committee supports modifications to modernize Alaska Natural Gas Transportation Act (ANGTA) and believes such modifications would be beneficial to an Alaska gasline project. The committee endorsed ten key policy goals that should be included in any new gasline legislation.

The ten policy goals developed to guide drafting of the legislation were debated by the full Council and ratified in concept by a majority of its members on September 25, 2001. Several changes were made as a result of points raised by Council members during the September 25 debate.

If Congress moves forward with new legislation as suggested by the producers, a principal concern of the Council is that Congress should take steps early to reaffirm the southern, or Alaska Highway, route as the sanctioned route for a natural gas pipeline, as a previous Congress did in 1977 when it ratified the President's choice of the southern route under ANGTA. Such a step would focus the attention of industry and federal agencies on regulatory and permit approvals for a project along this route.

This committee also notes that a southern route provides several advantages over other alternatives. Among these is use of the pipeline corridor for other purposes, including the possibility of constructing a railroad or other utilities over time. In addition, a southern route could facilitate access to highly mineralized areas which are located in close proximity.

A second concern of the Council was the probability that with a new initiative in Congress, an Alaska gas pipeline would be subject to Federal Energy Regulatory Commission (FERC) jurisdiction on issues important to Alaska without a defined role for the State with FERC. Such issues would include tariffs on intra-state shipment of gas, and access to and from a pipeline. The proposal for a joint board that would give the Regulatory Commission of Alaska (RCA) joint jurisdiction with FERC on issues affecting Alaska grew out of this concern.

Other concerns of the Council involved provisions to encourage hiring of residents of Alaska for a gas pipeline project, and the hiring of Alaskan Natives.

It was recognized by the Council that the pipeline project will be substantial and that, for all practical purposes, qualified Alaskan workers wishing to work on the project will be employed. Still, an explicit encouragement to hire locally will be a strong inducement for companies and unions to train Alaskans for pipeline-related construction and operating jobs. The skills developed in the Alaskan workforce as a result of training and employment will thus be a lasting legacy of the project.

The Council also considered the importance of pipeline access and the need for future open seasons to facilitate pipeline access for new discoveries. Failure to provide for additional capacity either at startup or through future open seasons could create a "monopoly" on pipeline capacity, discouraging exploration by non-owners. Any new gasline legislation must address this issue to protect the interests of the State of Alaska.

Other policy points guiding development of proposed legislation are detailed later in this report.

The committee recognizes the Governor's strong advocacy of the 10 principles, as reflected in his recent testimony before the Senate Committee on Energy and Natural Resources and in other forums. It would appear that the State's policy position is well understood by decision makers in Congress and the Federal Executive Branch.

With this in mind, the committee believes that it would be useful for the State Administration to continue its efforts with the commercial parties to develop a market driven solution to transport Alaska natural gas to market via the Alaska Highway route.

Close coordination and communication between the State, the North Slope producers and the pipeline companies could facilitate the establishment of a consortium of companies with the financial capability to build the pipeline.

In our opinion, current discussions among the parties concerning economic feasibility and reestablishment of the previous pipeline partnership underscore the need for such coordination at this time.

Background on ANGTA

Congress enacted the Alaska Natural Gas Transportation Act (ANGTA) in October 1976, after finding that the national interest called for the expeditious construction of a transportation system to bring Alaska natural gas to markets in the lower 48 states. The primary goal of ANGTA was to "provide the means for making a sound decision as to the selection of a transportation system . . . by providing for participation of the President and Congress in the selection process, and . . . to expedite its construction."[1]

To achieve that goal, the Federal Power Commission (the precursor to the Federal Energy Regulatory Commission (FERC)), held hearings and prepared a "Recommendation to the President," which recommended two possible overland routes through Alaska and Canada. The President then selected the southern route, the Alaska Natural Gas Transportation System (ANGTS), as the preferred alternative. Congress approved the President's selection by a joint resolution in November 1977.

ANGTA establishes the framework under which federal agencies (including the FERC) are to review and approve the ANGTS project. ANGTA supplements, but does not supersede, the Natural Gas Act

– which is the law that normally governs approval of natural gas pipelines, and requires a certificate of public convenience and necessity before interstate natural gas pipelines are built.

However, because ANGTA was designed to expedite construction of an Alaska gas pipeline, it contains numerous provisions that speed up administrative and judicial review. For example, ANGTA directs that any applications under it shall take precedence over similar applications and shall be expedited by federal agencies.[2] ANGTA also provides that a Federal Inspector be appointed to coordinate all federal activities and enforce federal requirements.[3]

In addition, ANGTA contains provisions dealing specifically with access to facilities and in-state access to gas. ANGTA provides that there shall be no discrimination against any shippers based on the degree of ownership in the system. It also provides that the State of Alaska is authorized to ship its royalty gas on the system and withdraw its gas for use within Alaska.[4]

Finally, ANGTA limits judicial review of any agency action to issues of whether the agency violated constitutional rights or statutory authority – effectively limiting the scope of environmental challenges to a project constructed under ANGTA.[5]

Because the Alaska segment of the project has not been constructed under ANGTA since its enactment 25 years ago, there may be outstanding issues regarding its current application. For example, the creation of legislatively designated areas—such as parks or wildlife refuges—may require re-routing portions of the project. This raises the question whether the project approved by the President has been altered so substantially as to render the findings in ANGTA ineffective. In addition, a competing project may be proposed under the Natural Gas Act, raising the issue of whether the preferential treatment required under ANGTA has already been provided, or whether an ANGTA project must be constructed before any other project designed to bring Alaska gas to the lower 48 states can be approved.

Summary of the "Alaska Natural Gas Pipeline Act of 2001"

The "Alaska Natural Gas Pipeline Act of 2001," set forth by the Alaska Gas Producers Pipeline Team, provides a streamlined administrative process and limited judicial review for non-ANGTA gasline projects. The legislation is designed to eliminate outstanding legal issues regarding whether non-ANGTA gasline projects may proceed absent the repeal of ANGTA.

Section 2 of the bill, "Congressional Findings," states that it is in the national interest to provide "as much regulatory certainty and expedition as practicable" for approval of one or more pipeline systems from Alaska to the lower 48.

Section 3 of the bill, "Congressional Purpose," states that the purpose of the bill is to expedite federal decision making, create an Office of the Federal Pipeline Director to coordinate federal agency decisions, and expedite and limit judicial review concerning both the Act and the approval process for any Alaska gasline project.

The bill defines "Alaska Facilities Gas Project" to mean any natural gas pipeline system that carries Alaska gas to the lower 48. It does not specify a preferred route.

Section 5 of the bill amends the Natural Gas Act to set out an expedited approval process for an Alaska gasline. It directs the Federal Energy Regulatory Commission (FERC) to issue approval within 18 months of an application if: there is an agreement to ship with a party that controls Alaska natural gas; rates can be established according to FERC's usual procedures; and if there is compliance with all environmental laws.

The bill states that the lead agency for preparing an environmental impact statement (EIS) shall be FERC, and that the EIS process shall be expedited and the final EIS issued within 18 months after an application is filed.

Section 7 of the bill establishes the Office of the Federal Pipeline Director. This office appears to have a function analogous to the Office of the Federal Inspector, created under ANGTA. The Federal Pipeline Director will coordinate all federal activities related to the pipeline project. It will be a "one window point" for filing and issuing all necessary permits and is responsible for coordinating and expeditiously completing all environmental reviews and studies.

The bill directs federal agencies to coordinate and expedite review of the gasline project and gives the Federal Pipeline Director the authority to remove discretionary requirements from federal permits if they would impair or prevent the expeditious construction of the pipeline.

Section 9 of the bill limits judicial review to claims challenging the Act itself, constitutional claims or claims that an agency is acting outside of its jurisdiction. Lawsuits must be brought within a shortened time frame, with jurisdiction in the U.S. Court of Appeals for the District of Columbia.

Section 10 provides that, if any provisions of the Act are invalidated, the remainder of the provisions will be unaffected.

Background on Canadian relations

First Nations

The Kaska First Nations located in Northern British Columbia and the Yukon continue to negotiate land claims and self-government agreements with the Government of Canada and the Province of British Columbia. While these negotiations are expected to continue for the foreseeable future, speculation is that when the time is right, the Kaska will be open to a side agreement on any proposed pipeline running through their territory.

The eight First Nations who have land claims along the proposed route of the Mackenzie Valley pipeline have been negotiating with producers since late spring of 2001. Early in October of 2001, seven of the eight groups came to an agreement on ownership sharing of any pipeline built through their territories. This agreement would grant 30% ownership to the First Nations Bands. The eighth, the De Cho, refuse to sign the agreement. While the Minister of Indian Affairs and Northern Development has been quoted as saying that one Band cannot hold a veto over any project, the De Cho believe that they have the right to refuse construction on lands they claim.

Position of the Government of Canada on Arctic Gas Production and Transportation
The Government of Canada has affirmed that in relation to this project, all departments and agencies will maintain route and project neutrality. In the spring of 2001, the Prime Minister set up a Cabinet reference group to study the current state of Canada's energy policy. The main issue of study was whether to express a preference for one route over another. A number of Cabinet Ministers expressed support for either the "over-the-top" route or a two-pipeline route with the construction of the Mackenzie Valley line happening first. After careful consideration of all available information and a careful review of the regulatory implications of each option, the Cabinet reference group recommended to the Prime Minister that the original position of route and project neutrality be maintained.

Provincial and Territorial Positions
Of the four non-federal jurisdictions involved in the issue, only the Yukon Territory is firmly supporting the Alaska Highway route. While they have not been overly aggressive in the past, they intend to become more aggressive in promoting the route with the Canadian Federal Government. The Yukon Government has commissioned an economic study of the benefits to Canada of constructing and operating the Alaska Highway route, and it is expected that this study will be released to the public in January of 2002.

The Northwest Territories is aggressively promoting the Mackenzie Valley line either in conjunction with an over-the-top segment or as a stand-alone line. Assuming the latter is chosen by producers, the Northwest Territories is demanding that this line be built before an Alaska Highway gasline. They are very active with the Federal Government, asking for financial incentives to ensure the line's construction.

The other two jurisdictions involved, British Columbia and Alberta, have remained route and project neutral. Premier Klein of Alberta has said that regardless of what line is built, he will not allow a "bullet line" to cross his province. He demands that Albertans share in the long term economic prosperity created by a line to the lower United States. Principally, he is referring to gas liquids and would like to see the petrochemical industry in his province benefit from them.

While it would seem logical for the government of British Columbia to be supportive of the Alaska Highway route, this government has only been in power since June 2001, and this issue has yet to be critically examined by the Premier and his Cabinet.

Recommendations

The committee endorsed 10 key policy goals that should be given consideration in any new federal gasline legislation. The 10 principles and corresponding legislative provisions are outlined below.

Key Principles
1. Find that the Alaska Highway natural gas pipeline is in the national interest.
2. Mandate the already permitted Alaska Highway route as the preferred route.
3. Provide opportunities for new pipeline participants, such as existing producers, pipeline companies and major Alaska companies.

Corresponding Legislative Provisions

- The 1976 Alaska Natural Gas Transportation Act (ANGTA) that established a process selecting the ANGTS project following the Trans-Alaska Pipeline and the Alaska Highway through Canada to the lower 48 should be the framework for any new gasline legislation.
- The legislation should provide for updating and modernizing the process provided in ANGTA for the expeditious environmental review and approval of a pipeline application for the Alaska Highway route.
- A finding that an Alaska Highway route would make an important long-term contribution to the nation's energy supplies and independence.
- A finding that an Alaska Highway route would have less potential environmental impacts and related delays in construction.

Key Principles

4. Provide a mechanism for Alaska communities and businesses to obtain access to natural gas from the pipeline.

Corresponding Legislative Provisions

- FERC should require the project sponsor to demonstrate how the sponsor plans to meet reasonable projections of in-state local consumption needs, including the needs of Fairbanks, Cook Inlet and rural Alaska. In addition, the sponsor should allow for possible future construction of a pipeline to tidewater for the export of LNG.
- The Regulatory Commission of Alaska should have concurrent jurisdiction with FERC to set just and reasonable rates for the shipment of natural gas over the Alaska section of the gasline for in-state users.
- The Regulatory Commission of Alaska should have exclusive jurisdiction to set just and reasonable rates for any lateral pipeline connected to the Alaska section of the gasline that serves in-state users.

Key Principles

5. Provide access to the pipeline for new natural gas discoveries that will keep Alaska's oil and gas industry healthy through new leasing, exploration and production.

Corresponding Legislative Provisions

- FERC should require the project to establish reasonable plans and procedures, including additional open seasons if necessary, for the expansion of the Alaska section of the gasline as new fields of natural gas are developed on the North Slope and throughout Alaska.
- FERC should be authorized to order expansions of the gasline in the future under reasonable, non-discriminatory terms.

Key Principles

6. Provide for Alaska hire and Alaska Native hire.
7. Provide for the use of Alaska businesses.

Corresponding Legislative Provisions

- To the extent allowed by law, Alaska residents and contractors should be employed when they are available and qualified. In turn, contractors should be encouraged to employ and train Alaska residents.

- Recruitment should be accomplished primarily by advertising in-state and using Alaska's job service organizations to notify the Alaskan public.
- The project sponsors must, whenever feasible, enter into construction contracts with Alaska firms and fabricate modules in Alaska.
- The gasline sponsors should be required to enter into an agreement to provide for pre-employment recruitment, on-the-job training, and employment of Alaska Natives.

Key Principles

8. Provide for a project labor agreement for the construction and maintenance of the pipeline, and for worker training.

Corresponding Legislative Provisions

- The project labor agreement should require all contractors and employees to agree to a total ban on strikes, lock-outs and other disruptive activities for the life of the agreement.
- The agreement should be designed to ensure a steady supply of skilled labor and a contractually binding means of resolving worker grievances.

Key Principles

9. Provide a priority for the use of American and Canadian steel.

Corresponding Legislative Provisions

- Only steel manufactured or produced in the U.S. or Canada should be used in the construction of the Alaska section of the gasline unless its use is inconsistent with the public interest or the cost is unreasonable. Factors to be considered in evaluating the public interest should include quality, availability and delivery times.

Key Principles

10. Provide for economic incentives to give investors in ANGTS additional levels of confidence.

Corresponding Legislative Provisions

- Accelerated depreciation on gasline investments.
- An investment tax credit for an approved ANGTS project.
- A tax credit for producing gas from the Alaska North Slope tied to a price floor.

Footnotes

[1] 15 U.S.C. § 719a.

[2] 15 U.S.C. § 719g.

[3] This provision was repealed in 1992. Pub. L. 102-486, Title XXX § 3012(a), Oct. 24, 1992, 106 Stat. 3128.

[4] 15 U.S.C. § 719k.

[5] 15 U.S.C. § 719h.

Alaska Highway Natural Gas Policy Council

Committee Report
Access for In-State Gas Use and Future Opportunities Committee
Ken Thompson, Chair

Purpose: The Access for In-state Gas Use and Future Opportunities Committee will address key issues and make recommendations on state policies to enable fair and transparent pipeline access for in-state gas use and for the creation of a broader natural gas business within Alaska upon commercialization of North Slope gas.

Goal #1: Assess current supply/demand for in-state natural gas use and assess potential demand for expansion of current use as well as conceptual new uses.

Recommendation:
A long-term clean energy plan and vision needs to be developed for Alaska, providing for substantially increased use of natural gas for residential and industrial use and for power generation.

Recommendation:
The State should take a long-term, broad and strategic view of its entire natural gas resources. This should include areas on the North Slope, including non-producing areas, Interior basins and in south Alaska. There is a significant potential gas resource base in Alaska much larger than the 35 tcf proven natural gas reserves in existing fields on the North Slope.

Recommendation:
The State of Alaska should undertake more intensive, updated geologic and geophysical studies of the natural gas potential of current non-producing areas, including Interior and Southcentral Alaska basins. This should include a more thorough assessment of basin geology and natural gas generation and migration utilizing the most modern technology tools, as well as a more thorough assessment of the producible methane gas potential from coal seams within Alaska. In recent years new tools, such as satellite imagery and soil sampling techniques, have been developed. Another gas resource that should be assessed is gas from gas hydrates on the North Slope and in Interior basins, which are very sizeable and could be developed in future decades as technology advances.

Recommendation:
The State should evaluate incentives and policies to spur the exploration by private companies for natural gas, to better delineate the natural gas resources not only on the North Slope but elsewhere throughout the State. Strategies and plans should be implemented to attract additional companies interested in natural gas exploration who now utilize new technologies, to the North Slope, Cook Inlet, the Interior basins and elsewhere in the state.

Recommendation:
A major gas pipeline should traverse Alaska if the State is to fully exploit its longer-term resources from all basins over 50-plus years and also to gain access to future multiple markets over the long-term. In addition such a pipeline could ensure long-term, reasonably priced supplies of energy to the Railbelt and other areas of the State thereby encouraging economic development.

Recommendation:
The State should facilitate favorable policies and incentives to encourage development by the private sector of a broader natural gas infrastructure within the State that meets the long-term clean energy demand of Alaskans at reasonable market prices.

Conclusions:
* Natural gas supply in Southcentral Alaska is decreasing while demand for natural gas in home and commercial use as well as for electrical generation is increasing. Additional reserves of natural gas will be needed to meet future demand.

* The natural gas demand in Southcentral Alaska in 1998 was 589 million cubic feet per day (mmcfd) and is estimated to have grown 1 - 2.5% per year over more than 30 years. Approximately 166 mmcfd is used for local utilities, 75 mmcfd for residential and commercial space heating use and 91 mmcfd for electric power generation. Three hundred-sixty mmcfd is for industrial use, 214 mmcfd for LNG export and 147 mmcfd for ammonia-urea manufacturing. Forty-six mmcfd is for fuel to operate oil and gas production facilities.

* Unless new significant gas reserves are developed, a shortfall in natural gas deliverability for peak winter demand is predicted for Southcentral Alaska by 2006-08. This deliverability shortfall may be offset by gas storage, by curtailment of industrial use or by bringing new reserves on line. However, replacement of the deliverability will add higher cost resources, substantially increasing natural gas and electricity bills for consumers and businesses in Fairbanks, Anchorage, the Mat-Su Valley and the Kenai Peninsula.

* By 2009 without significant new sources of gas, the continued operation of the LNG plant and/or the ammonia/fertilizer plant is at risk. The export license for the Kenai LNG facility expires in 2009. It is conceivable that the export of LNG would not be authorized beyond 2009, and rising gas prices may make it difficult for the ammonia–urea plant to compete in international markets.

*In the long term, conventional natural gas (excluding coal bed methane) in Cook Inlet will probably be unable to meet the needs of the Cook Inlet region even with the cessation of all industrial uses. A long-term solution to this pronounced shortfall in deliverability would be gas from the North Slope. Depending on the delivered price of North Slope gas, this may also allow the continued operation of the industrial plants, thereby saving over a thousand total jobs and maintaining property taxes and State revenues.

* By 2018, Southcentral Alaska may have to rely on other fuel alternatives: heating oil and coal. In the case of fuel oil and coal, there are clean air environmental consequences for citizens in Anchorage, the Mat-Su Valley and on the Kenai Peninsula.

* Current natural gas purchases by residential and commercial users in the Anchorage area total over $100 million per year. The deliverability shortfalls starting as early as 2006 could cause natural gas prices to increase, affecting business growth and corporate taxes to the State as well as affecting cost of living for residents.

* The most competitively priced and cleanest fuel for consumers in Fairbanks may be North Slope gas that can be delivered to the Fairbanks area through an offtake "hub" or tap in the main gas pipeline.

* Along the pipeline route from the North Slope through Interior Alaska, 14 large mineral prospects have been identified within 20 miles of the gas pipeline corridor. These mineral prospects are currently not economic, with the largest cost for development being energy cost. Testimony was given that some of these mineral prospects may be commercially viable if a reasonably priced natural gas supply was available.

* The natural gas resources in Interior basins and in South Alaska have not been fully explored and delineated, but earlier screening studies have indicated the presence of natural gas. Little exploration or development has taken place because of lack of transportation to market and perceived geologic risk. In some areas, very little is known about basin geology and natural gas generation and migration, yet natural gas has been recognized as present.

* Alaska has the United States' largest volume of coal beds, but little work has been done to quantify the methane gas potential from coal seams. In the lower 48 over the past fifteen years coal seam gas production has become a major supply source near locales where pipeline transportation is available.

* Potential reserves of methane gas trapped as gas hydrates in shallower geologic formations on the North Slope or in Interior basins could be very large. Recent studies in the lower 48 and Canada indicate trillions of cubic feet of entrapped natural gas as hydrates. Numerous research and technology studies are underway by the Department of Energy and private companies to better assess the gas hydrate resource base and technologies needed to commercialize this huge resource in the future. Alaska needs to better quantify its very large gas hydrate resource base on the North Slope and in other basins of Alaska, and to stay abreast of technology improvements.

* Interestingly, exploration companies new to Alaska such as Forest Oil, Andex Resources, Lappi Resources, Evergreen Resources and others have shown interest in the Interior basins for conventional gas exploration using new technologies and for coalbed methane. Four new exploration licenses totaling 4.8 million acres are underway as well as more extensive leasing of coalbed methane leases. This new exploration should continue to be encouraged through favorable State policies and incentives. If these gas resources prove to be of large size over the next 50 years, a pipeline option that offers access to markets outside the State will be necessary as in-state markets are somewhat limited in size.

* There is not a long-range energy plan for the State that positions for the marketing of natural gas from different basins, including the prolific North Slope. A pipeline traversing Alaska offers the best option to allow assessment and future marketing from all basins across the State into future multiple markets globally.

* Leases signed by the producers on the North Slope legally stipulate there is an implied covenant to market gas produced within a "reasonable time" and at a "reasonable price". It is assumed that 34 years since the start of production at Prudhoe Bay meets the "reasonable time" stipulation. Producers will thus have to sell their gas to pipeline companies or third parties if "reasonable price" offers or bids are received for their gas and assuming other bid terms are acceptable.

Goal #2: Assess how natural gas or natural gas products can meet the clean and economical energy needs of communities along the pipeline route and in rural Alaska.

Recommendation:
The State should sponsor a comprehensive economic and environmental study of assessing fuel switching in certain Interior and rural communities from diesel to cleaner burning propane to provide information for the likelihood of economic natural gas "hub" propane processing facilities.

Recommendation:
The State should sponsor a comprehensive economic and environmental study of assessing broader electrical power distribution to certain Interior and rural communities to provide information for the likelihood of economic power generation plants near natural gas "hub" offtake points.

Recommendation:
The State should encourage private investors to initiate an economic study of creating one or more "gas hubs" for gas distribution, natural gas liquid processing, and/or power generation near Fairbanks, with a spur line to Anchorage and other "hub" locations that could distribute to Valdez and Southeast Alaska cities. This would foster a broader clean energy natural gas, propane and electrical distribution system within Alaska once a pipeline is endorsed across Alaska.

Conclusions:
* Because a North Slope gas pipeline will likely be heavy-walled and high-pressure, and will likely transport large quantities of natural gas liquids, any "tap" on the pipeline for local access to gas will be very expensive and may require facilities to remove the natural gas liquids. It is possible that only one or two "hubs" for gas offtake, for local natural gas use or gas-based industrial development, may be economically viable.

* To other communities without large populations, affordable and clean energy from the gas pipeline might best be distributed from gas-fired power generation at the offtake hubs, or through bulk distribution of propane more widely across Interior communities and rural Alaska. Large quantities of propane, a well-known natural gas liquid fuel source, will be moved through the pipeline and can be removed at "hub" natural gas processing facilities.

* In an economic analysis of fuel-switching in Interior Alaska, the local cost of replacement or conversion of oil-burning stoves and generation equipment must be included, and the positive economics on the environment of cleaner burning natural gas, propane or electricity must be assessed.

Goal #3: Assess the costs or benefits of the state taking its royalty share "in-kind" for facilitation of in-state access and use.

Recommendation:
The State should retain its right to take its royalty share of gas on the North Slope "in-kind" or "in-value." This flexibility creates competition to maximize wellhead value for the State by either the producers or other firms such as energy trading companies interested in marketing the State's share of gas. The producers have requested a long-term commitment by the State and are asking the State to decide up front to take either "in-kind" or "in-value." The Council feels the flexibility to switch on six

months notice is very important, creates marketing competition and ultimately maximizing resource value. The State should not negotiate away its right to take its royalty share of gas "in-value" or "in-kind."

Recommendation:
The State could maximize the value of its natural gas royalty resource with a mixed portfolio of "in-value" and "in-kind" sales, with in-kind royalty marketed by energy trading companies such as Duke Energy, Enron, Williams Energy or major companies like them. The State should put its royalty "in-kind" gas out for bid and seek bids from multiple parties for contract terms and price. Such contracts should ask for a "floor price" equal to or exceeding the average netback wellhead price achieved by the three major producers, or from "in-value" sales as "insurance" that the energy trading companies are working in their marketing to beat the producers gas sales realization.

Recommendation:
When there are out-of-state sales using an energy trading company, the energy trading company will reserve the capacity and the liability associated with that capacity, and that liability will not fall back on the State.

Recommendation:
The State may choose to direct market some portion of its gas to in-state consumers using State staff, but it is recommended that sales to customers in outside markets be handled by professional energy trading firms, considering the complexity of and rapid change in those markets. This would also allow those firms to absorb the risk of nominating pipeline capacity and buying hedging instruments to lessen risk on pricing of contracts.

Recommendation:
By keeping some portion of its royalty share of natural gas "in-kind," the State may be able to make some contract deals with consumers in-state at more favorable terms than the producers, as the State might realize added dollar benefits through jobs and corporate taxation of value-added processing such as natural gas liquids processing, petrochemical manufacturing, power generation, etc. that may not otherwise be economically viable to entrepreneurs within the state. However, there should not be a subsidy in sales of royalty-in-kind gas. The State should receive a netback price for royalty gas equal to or greater than the market-based "netback value" of gas on the North Slope.

Recommendation:
To the extent practical, the State of Alaska should enforce its "higher of" clauses on natural gas royalty, as this could add value and ensure producers work hard in their marketing to obtain the best value in their sales of natural gas. When the State elects to take any share of its royalty gas "in-value," existing lease terms and statutes allow the State to receive royalty payments and production taxes on the "higher of" actual proceeds or market value. Other states, as well as the U.S. Minerals Management Service, are aggressive in ensuring all producers pay this "higher of" price for royalty and relevant taxes and receive such payments from the same producers that produce on the North Slope.

Recommendation:
Because of the complexities of the natural gas industry and the differences with the oil industry, the State should form a Natural Gas Services Group with people experienced in the natural gas industry,

shipping, marketing and trading so that the State becomes even more sophisticated in understanding deals and transactions that are often involved in the natural gas business. The group would provide an oversight function on sales of royalty gas out-of-state, but could also negotiate and manage in-state sales much like the Division of Oil and Gas now manages sales of royalty oil.

Recommendation:

For more cost effective development of in-state gas infrastructure resulting in more economical transportation of state royalty gas within the state, the State should encourage entities to examine the port authority concept of tax advantaged financing for a gas "hub," spur lines and other distribution facilities.

Conclusions:

* Current North Slope oil and gas leases, and State statutes, allow State royalty production share to be taken "in-kind," i.e. physically take the oil or gas and market the products itself or arrange for other parties to purchase the gas at market value contracts; or to take "in-value," i.e. allow the producers to sell the products and pay the State their realized value of wellhead price after deduction of certain transportation costs. The State has the option to switch between taking its royalty share "in-kind" and "in-value" every six months. Current state law requires any "in-kind" sales, however, to obtain values equal to or higher than "in-value" sales.

* The current North Slope producers have complied with the "in-kind" or "in-value" lease terms and statutes in other states and on federal offshore leases for decades and have instituted internal procedures that allow them to process the selection of "in-kind" or "in-value" promptly. Other states and the federal government also have internal processes for administering the switch between "in-kind" or "in-value" as does the State of Alaska for its royalty share of oil. The producers' arguments that Alaska must decide up front on "in-kind" or "in-value" to ease marketing and sales administration or to bring more certainty to gas transportation or marketing are not valid considering the same producers' decades of experience successfully administering such programs for transportation and marketing elsewhere.

* The natural gas industry in the U.S. is very sophisticated in gas trading and marketing. There are energy trading companies which may be able to market the State's royalty gas for a higher netback price than would be paid by the producers if the gas were taken in-value. If so, the State's leases include a "higher of" clause which means producers would have to pay royalties and taxes on the higher of their actual netback wellhead price or the actual netback wellhead price of an energy trader. This, in a way, creates competition and options to achieve the best possible wellhead netback value.

* In testimony from the General Land Office of Texas, the committee learned that Texas has similar "higher of" clauses in their state leases that they enforce. In 2000, enforcement of the "higher of" clauses, with producers paying royalties and taxes on the highest actual netback wellhead price achieved on various leases, resulted in additional revenues of $17 million. Alaska's royalty gas sales will be ten times higher than Texas' volume of royalty gas sales.

* Alaska may achieve higher prices on some of its royalty gas by allowing energy trading companies to market the State's "in-kind" share. The State of Texas takes 53 percent of its royalty gas in-kind and 47 percent in-value, and claims to achieve higher prices on much of its royalty-in-kind sales by achieving better negotiated pipeline tariffs, higher customer prices or integration for power generation.

* However, the flexibility in taking royalty-in-kind is important for other reasons as well as price. First, royalty sales will allow the State to periodically test the market, to assess whether it is getting fair market prices from producers. Second, allowing energy trading companies to market royalty gas will create more competition by accessing different customers than the producers and broadening the market exposure of Alaska's natural gas.

* While Texas is able to market its royalty gas with a small staff of state employees, Alaska should "outsource" its sales of royalty gas to the lower 48 or other outside markets to an experienced gas trading firm. Because large volumes of Alaska royalty gas may be marketed in several of the lower 48 gas markets or outside markets initially, a thorough understanding of and experience in those markets will be required.

* On the other hand, it may be more appropriate that the State negotiate directly for sales within Alaska of in-kind royalty gas as is now done with royalty oil, because of the better understanding of local conditions. A section within a new Natural Gas Services Group could perform this function.

* The concept of a public authority owning a segment of a natural gas pipeline within Alaska may present significant benefits for transportation of State royalty gas to in-state users. The tax advantage of a public authority, for example, would allow a lower tariff for transporting gas within the state, and resulting savings could help generate more business activity by providing natural gas at lower prices to consumers. The netback price, however, should remain at market values.

Goal #4: Determine the "best practices" for methodologies to achieve transparency in netback pricing valuation at the wellhead and transportation to assure fair and favorable pricing for in-state gas business creation and expansion as well as for taxation and royalty calculations.

Recommendation:
The State should keep a natural gas price netback valuation methodology based on actual sales proceeds, or sales contracts, and not change to a formula linked to average prices in gas trading hubs or some other general formula at least for the first several years of major gas sales. The State's right under lease terms and statutes to obtain actual realized prices for its gas and natural gas liquids should not be negotiated away.

Recommendation:
With the growing natural gas liquids (NGLs) business in the U.S., the State should keep a natural gas liquids price netback of gasline liquids based on actual sales proceeds, or sale contracts, of the liquids and not accept a value for the liquids based on a BTU adjusted basis of the gas stream unless there is clearly a higher value obtained by BTU-based sale. The State should be very sophisticated in its assessment and knowledge of the business of NGLs, as revenues from NGL sales will be a substantial part of revenues from the overall gas stream.

Recommendation:
Alaska statutes should be reviewed and updated to require information on sales spot transactions, sales contracts, actual transportation costs and other information be made known to the State, much as statutes in Texas and other locations provide for. When updating these statutes the process should

be clarified in a way that assesses the "lessons learned" on the Alaska oil valuation disputes and provides for more timely resolution of any differences in valuation.

Recommendation:
Alaska statutes should be reviewed and updated to require information on "affiliated sales" by producers be made known to the State, much as statutes in Texas and other locations provide for.

Conclusions:
* Several years of North Slope oil production disputes on netback pricing valuation resulted in major hearings and extended litigation. The State was able to resolve these issues after several years of production once access to oil sales contracts, invoices and transportation charges allowed the State and the producers to agree on a formula for purposes of calculating royalty. The experience with production made both the State and producers confident that the formula tracked market values, or actual proceeds of oil sales. This history may or may not be of value in regard to gas price valuation. Certainly it is in both the State's and the producers' interest to avoid replication of the lengthy disputes on royalty and severance taxes experienced with the first decade of North Slope oil production.

* In contrast to oil, there have been no sales of North Slope gas, nor are gas sales contracts in place or other similar information available. For the first several years of natural gas production, the State should certainly rely on existing measures of royalty value in the lease, which include value based on sales proceeds. The State should, however, review the oil valuation disputes and see if additional clarification of information, data, definitions, etc. is required to achieve a better mutual understanding by the producers and the State to lessen points of future disagreement. An agreement on an alternative formula for royalty valuation on gas may never be needed to maximize value to the State. In the future there could be sufficient production experience to allow agreement on a formula for valuation if needed. Billions of cubic feet of natural gas are sold from various states and federal leases under the actual netback pricing mechanism. While there have been disputes, there have rarely been pricing formula agreements adopted in lieu of an actual netback pricing approach.

* Natural gas hub spot prices could be too easily affected, at certain times and at certain locations, by market forces external to Alaska. This concern of hub posted prices for oil was evidenced by the Federal Trade Commission (FTC) forcing a sale of oil trading hub facilities in the Cushing area because of the concentration of ownership of facilities at that trading hub location by BP, Amoco and ARCO upon their mergers. While the FTC did not claim unfair trading affecting oil hub posted prices would or was taking place, the FTC did feel too much concentration of power at such trading hubs could affect posted prices. It may be possible that concentration of interests and gas trading spot volumes at certain gas trading hubs periodically in the future could potentially skew hub prices similar to the FTC concern. Alaska should simply use the maximum, actual realized price as fair market value.

* Information on sales spot transactions, sales contracts, actual transportation costs and other related information will ensure that reliable data is provided so the State can accurately calculate the actual realized wellhead netback gas price. Such information is provided by the North Slope producers on other states' leases where required and on many federal leases. Companies have internal record keeping and software systems in place to provide in a timely manner such information for accurate calculation of netback gas prices.

* Having information on "affiliated sales" will ensure the State has knowledge when a producer sells natural gas to an affiliated subsidiary company for additional value added marketing, processing or manufacturing. Having such knowledge of affiliated sales can help the State screen that a fair market value is being obtained for the gas, versus a value being obtained that is less than market while the affiliate captures additional value downstream.

* Testimony to the subcommittee showed that Texas bases its royalties on actual proceeds and requires producers to report to the State, on a monthly basis, information on sales contracts, points of sale and transportation costs. Texas General Land Office staff has developed computer software to track these transactions and to ensure the accurate calculation of lease netback for purposes of producers, in turn, calculating accurate royalty and tax payments. The companies that report these transactions in Texas include all three of the major gas producers on the North Slope. Texas has offered to make its computer models used in monitoring transactions available to Alaska.

Goal #5: Recommend policies that assure clear and transparent rules for access to natural gas into and out of the gas pipeline for Alaska businesses and customers.

Recommendation:
The State must develop a clear and sophisticated understanding of the "open season" rules governing access to a contract carrier pipeline and devise strategies to facilitate access to the pipeline for firms exploring for or developing new gas discoveries on the North Slope or Interior basins.

Recommendation:
The State should incorporate in any federal legislation the right to gas access in-state. This right is provided in ANGTA but is not provided in the producers' recently proposed federal legislation.

Recommendation:
The State should first seek federal legislation that gives the Regulatory Commission of Alaska (RCA) authority to set tariffs for the transportation of intra-state gas used in-state similar to that authority given to the RCA for tariff review on the TAPS oil line. The state RCA should review applications for pipeline access within the state to ensure fairness in pre-determined fees and terms based on reasonable rates of return for investors who ship to in-state consumers.

Recommendation:
Failing to achieve RCA obtaining sole authority in-state, the State should seek through federal legislation the creation of a joint board between the Regulatory Commission of Alaska and the Federal Energy Regulatory Commission (FERC) that would have authority to set tariffs for the transportation of intra-state gas used in-state. This joint board should participate in review of applications for pipeline access within the state to ensure fairness in pre-determined fees and terms based on reasonable rates of return for investors who ship to in-state consumers.

Recommendation:
Alaska should consider including a "fairness" clause in the granting of State right-of-way approvals across state lands to guarantee fair access, similar to provisions developed by Texas for pipeline rights-

of-way approved across state lands. Such a clause will give the State valuable leverage in negotiating fair access rules. The clause could also provide an avenue for appeal to the RCA in the event of disputes.

Recommendation:
The State should complete a thorough socio-economic study of various approaches to in-state natural gas pricing of in-kind royalty gas.

One approach is that the sales price of in-kind royalty gas or gas liquids to in-state users, whether private or State, be based on the market netback price of gas on the North Slope (which is determined by subtracting actual pipeline transportation costs from actual realized market sales prices in the lower 48 or other outside markets) adjusted for intra-state tariffs actually incurred for the transportation of the gas to the in-state access point, or hub, and then transportation costs to the consumer with allowance for a reasonable rate of return on investment. Price of gas or gas liquids to in-state users should not be based on comparisons with alternative fuels, such as diesel. Providing that the intra-state tariff is determined on a prorated basis and not the "postage stamp" methodology, this policy will create a supply of reasonably priced, clean energy for communities in Interior Alaska, and ultimately Southcentral Alaska if a spur line is built. These more affordable natural gas prices would be passed along to consumers who purchase from a regulated utility but may not be passed along to consumers who purchase from a non-regulated company. A problem with this approach is that the State receives a potentially lo ver netback value than if the price is determined through competition with other fuels. This may favor the consumers in that area at the cost of lower State revenues. On the other hand, such an approach could mean more affordable natural gas to a large number of customers who purchase from regulated utilities, potentially enhancing economic development and quality of life for businesses and consumers.

Another approach is that the sales price of in-kind royalty gas or gas liquids to in-state users should be based on being competitive with the pricing of alternative fuels, as that may create higher netback prices resulting in higher royalty and tax revenues to the State. This would potentially increase the revenue received by the State but would not significantly lower the costs of consumers using this in-kind gas or gas liquids. However sellers other than the State could compete for these higher netback markets and so drive the price down well below the alternative fuels.

Conclusions:
* Some existing, large pipeline companies in the lower 48 have built pipelines with spare capacity as a speculative investment, allowing for future growth in volumes and revenues. Some pipeline companies do not invest in speculative capacity. Producers also tend not to invest in speculative, spare capacity but tend to construct to immediate capacity needs.

* Without spare capacity in the pipeline, it is very important that the State have a clear understanding of the "open season" rules and how to position for new entrants being allowed to produce into the pipeline.

* It is recognized that with a thick-wall, high-pressure pipeline, access taps and liquids processing facilities will be expensive. Points for gas offtake might be limited economically and operationally to only one or two distributions "hubs" along the pipeline route in Alaska.

* With a limited number of "hubs" for offtake, it may be more economical for several Interior and rural communities to obtain the clean energy not by direct natural gas use, but by benefiting from potentially economic electricity generation and natural gas liquids (propane) distribution from the centralized "hub" location(s).

* To fairly govern gas taken off at an in-state distribution hub(s), general access terms should be developed in advance by the RCA (or the joint board of RCA and FERC) that are clear and understandable. Similar general terms have been developed to govern contracts at gas trading hubs in the U.S., United Kingdom and the European Union.

Goal #6: Assess pipeline sizing and the pipeline "contracted volumes" structure for growth of in-state use and/or potential future export markets to Asia and the West Coast, or expansion of deliveries to the lower 48.

Recommendation:
The State should investigate ways of working with pipeline transmission companies as investors to build in excess capacity, to provide space for transporting new gas that will be discovered on the North Slope or Interior basins.

Recommendation:
The State should evaluate innovations in using part of its "in-kind" royalty share in contract sales to energy trading companies who can bid for shipping capacity which then may be used in a creative way in the future to ship gas from new discoveries while the State elects at the time of new discoveries to change and sell the originally nominated royalty gas volumes "in-value."

Recommendation:
The State should seek an order by FERC, or federal legislation, for periodic open-season nomination periods, to allow for additional capacity to be built for new gas, when triggered by requests from existing or potential producers, transporters, shippers, customers or the State.

Conclusions:
* Failure to provide for additional capacity either at startup or through future open seasons could have the effect of creating a "monopoly" on pipeline capacity by existing producers, discouraging exploration by others who are not owners of the pipeline.

* Strategies for natural gas pipeline open season nominations and shipping arrangements become very complex. A new Natural Gas Services Group could have such expertise in-house or these skills could be out-sourced to experienced gas trading firms.

* Because of current lease terms and statutes, the producers must allow enough capacity and construction size to ship the entire volume of the State's royalty share of gas "in-value" if the State were to elect at any time to have its royalty share sold direct by the producers.

Goal #7: Evaluate conceptual options for future value-added projects during the 50-year life of gas reserves for in-state use and/or export to Asia and the U.S. West Coast.

Recommendation:
No one can rule out with certainty the viability of value-added processing of natural gas in Alaska over the next 50 years. Alaska should have a natural gas pipeline that allows this option to remain open. The previous recommendations regarding access, reasonable tariff and pricing, and capacity expansion will keep these options open.

Recommendation:
Gas and gas product markets are highly cyclical in price and somewhat cyclical in demand, and somewhat regional in nature; thus the State should facilitate a pipeline option that will allow access to multiple markets in the future.

Recommendation:
As markets change, the State should take a proactive role in encouraging investors to consider the possibilities for liquefied natural gas (LNG), gas-to-liquids (GTLs), expanded uses of natural gas liquids (NGLs such as propane, butane) and downstream processing such as petrochemicals.

Conclusions-General:
* Original investors in the Trans-Alaska Pipeline System, the producers, estimated the life of the North Slope oil fields at 25 to 30 years. Twenty-five years have passed since startup of the TAPS line, and these investors are now applying for a 30-year extension to the rights-of-way for TAPS, so that oil developed since the pipeline startup can be shipped to market.

* The same circumstance may develop for North Slope gas, as exploration continues on the North Slope. Accordingly, the State should position itself for a 50-year life for a new natural gas industry and encourage development of a system that will access multiple markets. Only a gas pipeline following the southern route will be able to access additional markets through a spur line to an LNG plant on the southern Alaska coast.

* Oil and gas are commodities, and all commodity markets experience supply/demand and price cycles. If Alaska has access to multiple markets for gas, to the lower 48 through an all-land pipeline, to the U.S. West Coast and Asia through LNG shipments, and into the growing petrochemicals industry through sales of gas and natural gas liquids, the State will benefit because the commodity cycles may be different in these markets at different times as has been past history. In the future, there could be a more uniformly priced global gas market; however, there will likely remain cycles in volume demand or demand trends by regions.

* There is also the longer-term potential for a gas-to-liquids industry, with plants in Alaska manufacturing clean-burning liquid fuels directly from natural gas, and for development of new industries related to the petrochemical industry. These may be important future "value-added" industries for the state over the long-term.

Conclusions-LNG:
* Both Cambridge Energy Research Associates and the gas producers have provided information to the committee that the cost of delivering LNG to Asian markets is currently not competitive with

LNG supply from other sources, such as Indonesia, Malaysia, Australia and the Middle East.

* Yukon Pacific Corp., the Alaska Gasline Port Authority and a citizens' group have presented information that they believe LNG export from Alaska is currently competitive. Yet none of these organizations have secured substantial financial backing or presented firm contracts for sales of LNG.

* Despite this, no one has presented information that rules out LNG in the future. Asian nations may want to secure large-scale supplies of LNG from Alaska for purposes of energy security, so as not to be dependent on one or two regions such as the high-risk Middle East for the majority of import needs. Therefore, it is in Alaska's interest to maintain the flexibility to be able to supply LNG to export markets, or to U.S. West Coast markets, in the future.

Conclusions-GTL:

* Large-scale gas-to-liquids projects, the making of clean-burning liquid fuels from natural gas, could be an option for North Slope producers if they do not proceed with a gas pipeline project. These liquids could be shipped down the existing trans-Alaska oil pipeline. Testimony from the producers and information presented at a recent international conference on gas-to-liquids, held in Girdwood, indicate that large-scale application and commerciality of such a remote resource of gas as the North Slope reserves using GTL technologies may be a few years in the future, if ever, versus competitive sources of gas elsewhere that could use the GTL technologies.

* There is sufficient potential for growth of North Slope gas reserves, and the expectation is that there will be sufficient reserves established for both a conventional gas pipeline and gas-to-liquids plants, once it can be shown that Alaska GTL plants can be commercially viable on a large scale.

* A possible negative for a stand-alone GTL project, without a gas pipeline, is that it would lock Alaska into one market for its gas: the West Coast fuels markets. It may not be cost competitive to serve other markets with GTL fuels from Alaska because of shipping distances. However, if a gas pipeline is built, GTL could be a potential value-added product that reaches a different market: the future demand for clean-burning fuels on the U.S. West Coast.

Conclusions-NGLs:

* Information presented at the Girdwood GTL gas conversion conference indicates major breakthroughs in cost-reductions of processing natural gas liquids through related technologies. Costs of processing NGLs today is seen as much less than was the case a few years ago. This could serve to enhance the viability of a gas pipeline that also carries NGLs to market.

* The NGL business in the U.S., mainly in propane and butane, is a very large multi-billion dollar industry and a key component of the integrated natural gas industry. The producers are studying the construction of a large NGL extraction plant in Alberta.

* A gas access and distribution hub(s) built near Fairbanks or Delta Junction could facilitate expanded production and sale of NGL products in the state, for distribution to Interior or rural communities. Fuels from NGLs have the potential for becoming an economic and clean-burning alternative source of energy for Alaska communities. The Williams Companies and other firms in Fairbanks are now assessing investment opportunities and potential for uses of NGLs.

Conclusions-Petrochemicals:
*A previous assessment of a petrochemical industry for Alaska, done by Dow-Shell, found that a petrochemical industry would not be viable in Alaska at the time that study was done. However, changed circumstances have affected several assumptions used in the study. Dow-Shell assumed that a separate, small-diameter gas liquids pipeline would be built from the North Slope and envisioned an industry based on manufacturing complex petrochemicals.

* Today there is a proposal for a natural gas pipeline that could also carry NGLs, so there is no need for a separate pipeline. Also, one new study underway of using NGLs, by Williams, envisions manufacturing a simpler petrochemical product than that envisioned in the Dow-Shell study.

* Williams' study is considering the making of polypropylene, one of several petrochemical products in the olefin family, and shipping the product via the Alaska Railroad to Anchorage for shipment to markets in Asia. Olefins are fundamental feedstocks for the rapidly growing plastics industry. It is a business involving $41 billion in annual sales, with significant supply shortfalls expected in 2006. Williams has completed an initial screening study and is now engaged in a more detailed analysis of its study.

* All three major producers on the North Slope have recently expanded their olefins business in the lower 48. All three of the major producers have extensive separate businesses in olefins in the U.S. and Canada. For example, ExxonMobil is ranked as the number 3 producer of ethylene in North America, while Phillips-Chevron is number 4 and BP is ranked number 7.

Goal #8: Determine strategies to promote and attract investment for in-state distribution and value-added processing.

Recommendation:
The state should develop and periodically update a formal marketing plan to attract investors in Alaska who may be interested in in-state gas distribution or development of value-added industries. Assisting this could be an additional function of a new Natural Gas Services Group within the Department of Natural Resources.

Conclusions:
* It should be recognized that Alaska businesses, such as Enstar and Fairbanks Natural Gas Company, have already voiced interest in developing more in-state distribution.

* While the scale of in-state processing may not be attractive to the major producers, in-state value-added businesses may be of interest to Alaska Native Corporations and other Alaska companies once a gas infrastructure exists.

Alaska Highway Natural Gas Policy Council

Committee Report
Environmental Considerations Committee
<u>Peg Tileston, Chair</u>

Goals:
- To define and address key environmental issues, both natural and human, associated with the construction of a natural gas pipeline.
- To make recommendations for policies and procedures necessary to ensure that the design, construction and operation of the natural gas pipeline will proceed in an environmentally sound manner.
- To identify potential environmental benefits of a natural gas pipeline.

Introduction and Background

The proposed Alaska natural gas pipeline project is comparable to the Trans-Alaska Pipeline System (TAPS), which was built in the mid-70s to transport crude oil from Prudhoe Bay to the Valdez Marine Terminal. The gas pipeline under consideration is proposed to be large-diameter (up to 52 inches), high-pressure, chilled, completely buried (except for above ground crossings of the Yukon River and possibly the Tanana River), and supported by a number of compressor stations. In addition, a large conditioning plant will be required on the North Slope to treat the natural gas before it enters the pipeline. Furthermore, the proposed Highway route would be international, crossing portions of the United States and Canada and thus requiring trans-boundary coordination of the pipeline's daily operation, maintenance and emergency response capabilities. Except where noted the comments in this report deal solely with the Alaska segment of the proposed gasline.

Much has been learned from the TAPS experience over the last 27 years. When the State of Alaska and federal agencies undertook oversight of the design and construction of the TAPS project, there was limited understanding of the impacts and problems associated with a project of that magnitude. Delays caused by litigation provided industry and agencies with an opportunity to review and improve TAPS engineering design and construction planning. This review resulted in successes, but there were also unanticipated failures. Careful planning and design, as well as continued vigilance in monitoring and enforcement are essential to reducing environmental concerns.

Oversight and regulation of TAPS has been enhanced over time due to a commitment to continuous improvement of the oversight process by industry, government and the public. In the early 1990s, the Joint Pipeline Office (JPO) was established to provide a coordinated, cooperative federal-state structure for oversight of the line. This has proven to be an effective inter-agency oversight mechanism. A similar joint office, the Gas Pipeline Office (GPO), has been established for the natural gas pipeline, and it is important that it be adequately funded and staffed with highly qualified personnel to provide the needed agency liaison and coordination of the permitting standards and process.

The impacts of a project of this magnitude will be extensive, particularly during the construction phase, and must be considered not only in the context of the natural environment but also as it will affect the human environment. Quality of life in communities can be degraded in numerous ways ranging from reduced services, traffic congestion, crowded schools and health services, reduced recreational opportunities and inflationary pressures. Rural residents depending on subsistence may experience increased industrial and recreational activities in traditional hunting and fishing areas. On the other hand, pipeline construction will create jobs and increase short-term economic opportunities, and the completed pipeline could supply natural gas to communities that presently depend on less efficient liquid petroleum products for energy, altering lifestyle and environmental patterns ranging from fuel consumption to air quality over the long term.

The charge for the Environmental Considerations Committee of the Natural Gas Policy Council is to make recommendations to assure that the project follows Governor Knowles' policy of "doing it right." The committee has determined that its most effective contribution is to recommend needed policies and procedures, many of which should be put into place as early as possible during engineering design and prior to the start of construction. Every effort must be made to ensure that best technology and best environmental practices are implemented in order to make the project as environmentally benign as possible, and to make sure that the net impact on human lives will be positive. The following recommendations to decision-makers are presented with these goals in mind.

Recommendations and Supporting Rationales

1. Endorse the Alaska Highway route as the environmentally preferred pipeline route that minimizes the potential adverse environmental effects and maximizes potential environmental benefits to Alaska.

An Alaska Highway route would limit the gasline to an existing corridor, minimizing impacts to the environment as well as to fish and wildlife. It would also allow Alaska communities access to a cleaner, more efficient fuel. In addition, a highway route following the TAPS line would make oversight of both lines more efficient and effective. At hearings of the Gas Policy Council, Alaskans voiced overwhelming support for the environmentally preferred southern route.

A rigorous environmental review should be required. There are three approaches to this. The most expeditious approach but the one most susceptible to challenge is to meet the requirements of Section 5, subsection III of the President's Decision relating to the Alaska Natural Gas Transportation System (ANGTS) which anticipated the development and public review of detailed plans to protect the environment using the best of current science and technology. The two other approaches are either a supplemental environmental impact statement (EIS) building on the ANGTS EIS or a full EIS done in an expedited manner using information from the ANGTS EIS. The outcome of any process should spell out for public review the alternatives associated with the Highway route, the environmental pros and cons associated with them and mitigation measures that should be taken to avoid or minimize adverse impacts.

Any frontier route would require a "start from scratch" approach, including collection and analysis of physical, biological and social data, and determination of required technology.

2. Adequately fund and staff a natural gas pipeline office that is housed in one place to facilitate communication, coordination and cooperation among all affected state, federal and Canadian agencies.

Lack of timely and complete communication among agencies can have severe consequences on any project, but can be particularly difficult in one of this size. A facilitated review of the JPO operation by all the involved agencies to note procedural changes they might recommend to improve effectiveness and efficiency would be beneficial. Acquiring personnel with the necessary technical and scientific expertise may be difficult for both federal and state agencies when competing with industry, which will be hiring for the same positions and will have considerably higher salary scales. Every effort should also be made to include the considerable number of borough and local agencies concerned with the various project alternatives, along with Alaska Native corporations, tribes and villages that will be affected by a pipeline right-of-way (ROW).

3. Recommend that the Gas Pipeline Office (GPO) conduct a thorough review of "lessons learned" from TAPS design, construction and operation. This review should include public comment and public participation. Use "lessons learned" to develop procedures for the gas pipeline that ensure past mistakes are avoided and successes repeated.

A natural gas pipeline following the TAPS/Alaska Highway corridor will have many environmental concerns similar to those of the earlier project. Certain differences need to be identified and addressed, such as the effect of a buried, chilled pipeline crossing beneath streams, geologic and hydrologic data for areas where TAPS is not buried, and design and operational differences between a low-pressure, hot oil line and a high-pressure, cold gas line. In addition, Canadian and other high-latitude gas pipelines should be studied for lessons learned.

4. Establish an open and available data and information process for the public, agencies and industry.

Frustration and suspicion take hold when individuals, organizations and communities are unable to get information on issues of concern in a timely and appropriate manner. Such a process should start at the beginning of the project and make available all non-proprietary material. Meaningful involvement by affected communities is important. Effort should be made to include all stakeholders, not just decision-makers. Websites, e-mail addresses and information repositories, such as local libraries and borough offices, should be used to disseminate information. A central site, preferably the Alaska Resource Library & Information Services (ARLIS), should be used as effectively as possible and adequately funded. An information clearinghouse such as the Exxon Valdez Oil Spill Library (which is now consolidated in ARLIS) could be an appropriate approach.

5. Establish mandatory training for all personnel involved with the gas pipeline project.

Timely, appropriate and sufficient training is vital for all personnel associated with a major project. Such training should start with applicable federal, state and local laws and regulations, agency mandates and responsibilities, enforcement options and penalties for noncompliance, best practices, and appropriate technologies. Government and industry should coordinate to ensure commensurate levels of training for the public and private sectors, including all contractors and subcontractors. Sessions to update personnel as the project progresses should be included, along with required orientation for those joining it.

6. The State should take a long-term view of the gas pipeline to minimize environmental concerns.

In view of the likely long-life of this project, the State should encourage a long-term view be taken in design, construction, operation and maintenance in order to mitigate environmental risks over the entire life of the project.

7. A records management system for compiling and maintaining complete and updated documentation should be in place at the beginning of the project and maintained and updated throughout the life of the pipeline in accordance with professional document control standards. The State must have copies of all documents.

The TAPS experience has shown that older engineering drawings, including "as-builts" and documents confirming original facility configurations and placements, have not always been readily accessible by pipeline managers and regulators when needed. Establishing a professionally designed and maintained document control system will help to ensure that accurate records from every phase of pipeline development remain rapidly retrievable under unforeseen future circumstances. Recent advances in technology will undoubtedly aid this process.

8. Assure that effective and adequate monitoring and enforcement systems are in place at the start of the project and continue throughout the life of the pipeline.

Adequate funding will be needed to ensure that a sufficient number of appropriately trained agency personnel are available for monitoring and enforcement throughout pipeline construction and operation. Agency personnel without a working knowledge of pipeline construction, operation and maintenance will have little credibility with their industry counterparts. Training of agency personnel associated with all aspects of the pipeline should be integral to the project. Such training should emphasize the prevention and early detection of problems, and understanding of regulations, codes and penalties. Enforcement of regulations and codes is essential but will not occur without trained personnel who are actually available on site.

9. Direct the GPO to establish a comprehensive citizen's involvement plan. This effort may include the creation of a citizen advisory council with representatives from communities affected by construction of the pipeline.

A determined effort should be made to aggressively involve and engage affected communities during the planning and construction phase through a coordinated federal/state effort. If necessary as determined by the federal/state plan, a citizen advisory council should be formed and adequately funded to receive and evaluate information and respond to pertinent issues. If established, the council would also evaluate their role following construction of the pipeline.

The public involvement process should also include a full review, including stakeholder involvement, of proposed federal grant and state lease right-of-way provisions and stipulations.

10. Provisions should be incorporated into ROW lease agreements to ensure that adequate dismantling, removal and restoration (DR&R) funding will be available for the Alaska segment of the natural gas pipeline.

The actual DR&R provisions will depend on ownership of the pipeline and should take into consideration the long life of the asset.

11. Perform a full security review and develop a comprehensive and detailed security plan early enough to influence the pipeline design and alignment process.

Heightened security concerns throughout the United States should be reflected in the engineering design and alignment of the natural gas pipeline, which will be a significant part of America's domestic energy supply. Any aspect of the design of pipeline facilities and structures that would be particularly vulnerable to sabotage, such as compressor stations, bridge crossings and above-ground valve housings, should receive attention from a security standpoint early in the design process, and not as an afterthought. This concern applies also to the alignment, which may present opportunities for modifications or adjustments that will minimize the potential for harm.

12. Continue to ensure that environmental scientists and permitting specialists work side-by-side with design engineers and construction planners from the earliest stages of the project through to its completion.

It is essential that environmental safeguards be built into the design of the project, not added as an afterthought to satisfy regulatory requirements and stipulations. Preliminary engineering design products will be used to support major permit applications with long lead times and must contain fully integrated environmental features at that early stage. This can best be accomplished if environmental and permitting specialists work on the same teams and in the same facilities as the engineers.

13. The State of Alaska ROW lease should require long-term environmental surveillance and monitoring, and annual reporting. This function should continue throughout the life of the pipeline.

14. The GPO, in cooperation with the federal government, should continue to coordinate the trans-boundary aspects of construction, operation and maintenance of a gasline, including operations control and emergency response.

Although it may cross land belonging to two nations, the gas pipeline will be a single integrated system. Emergencies, whether structural, operational or environmental, will not respect the international boundary. The U.S. and Canada must establish integrated control protocols that can regulate the pressure and flow of gas through the pipeline as a single system and thus respond quickly and effectively to emergencies. This will require open communications, shared data and a close working relationship between personnel of both nations. The State should look to other international pipelines, particularly between Canada and the United States, for models in handling the trans-border oversight aspects of construction, operation and maintenance.

Section III:

Meetings and Public Hearings

Alaska Highway Natural Gas Policy Council

AGENDA

Thursday, March 1, 2001, 10:30 a.m. to 2:00 p.m.
Anchorage Sheraton Hotel

I. Welcoming remarks from Co-Chairs Jim Sampson/Frank Brown

II. Opening remarks from Governor Tony Knowles

III. Opening remarks from Lt. Governor Fran Ulmer

IV. Presentation from Department of Natural Resources Commissioner Pat Pourchot

V. Presentation from Cambridge Energy Research Associates

VI. Ten-minute break

VII. Working lunch and Council member self-introductions

VIII. Establish organizational structure

IX. Establish timeline and public hearing schedule

X. Closing remarks from Council Co-Chairs Jim Sampson/Frank Brown

Alaska Highway Natural Gas Policy Council

Full Council Meeting Summary
March 1, 2001, Anchorage Sheraton Hotel

Co-chair Jim Sampson opened the meeting, explaining that the Council's structure, organization and schedule of meetings would be discussed in this first meeting. Sampson introduced Frank Brown, his fellow co-chair.

Brown commented that it was his hope, and that of Sampson, to steer the Council through a process to get large amounts of input from individuals and organizations around the state. He congratulated the governor on securing the support of the National Governors Conference for a gas pipeline bringing Alaska gas to lower 48 markets.

Governor Knowles made several opening remarks, expressing thanks to members of the Council for agreeing to serve. "Many of us participated in construction of the first pipeline, the oil pipeline, and rarely do people have an opportunity to participate in a second major pipeline project. We've seen the bumper sticker, 'Please let there be one more boom.' Now there can be a second bumper sticker, 'We did it right this time.'"

Knowles said he created the Gas Policy Council to insure that Alaskans' interests and potential would be promoted and to insure Alaska hire and a fair share of resource revenues to the State. The mission is to promote an Alaska Highway gas pipeline that will also help create a natural gas industry for the state. A project of this magnitude only comes along rarely, and Alaskans have a deep interest in its development. It could open the door to development of the 100 trillion cubic feet of gas potential believed to be present on the North Slope.

The Administrative Order creating the Council identified eight broad topics of inquiry, and the governor realizes more may be added by Nov. 30. Knowles urged Council members to ask tough questions.

Knowles said it is his belief that the best way to develop Alaska's gas is with a pipeline along the Alaska Highway to the lower 48. He added that the consensus of the energy world is that the only market that would ensure an Alaska pipeline is financed is in the U.S. We must act with a sense of urgency to supply that market and to seek national and Canadian consensus in support, the governor said.

There is no question that there has been a long-term structural change in the gas supply and demand situation in the U.S. The urgency is that supply to meet the demand gap will come from other areas if Alaska's gas is not available. "We need to be in at an early stage of development," the governor said.

U.S. and Canadian support is needed. In 1977 an international agreement was signed, which indicates the issue of Arctic gas development is of national importance in both countries. The issue is now beginning to get national attention once again. Knowles noted positions taken in support by the Interstate Oil and Gas Compact Commission, an association of energy-producing states, as well as the Western Governors' Conference and the National Governors Conference.

Because of the earlier work, the Alaska Highway route has already gone through considerable environmental review, the governor said. The fact that the highway route was approved earlier is a tremendous asset. The alternative northern route has had no environmental review, and the State of Alaska has some serious concerns with the effects of large-scale dredging of a pipeline trench in the Beaufort Sea. Even if the northern route is pursued, its approval will be far in the future, Knowles said.

The governor said he has asked Interior Secretary Norton and Energy Secretary Abraham to consider the highway route as an issue of national importance, and they have agreed to consider this. Support from Canada is also needed because 1,800 miles of the pipeline will cross Canadian territory. It is important that the Alaska Highway pipeline be seen in Canada as a way to also help develop Canada's Mackenzie Delta gas. Overall, the project should not be exclusive to other projects. It will help make an LNG export project more viable, Knowles said.

The Council's mission should be to look closely at how the project can create a natural gas industry for the state, the governor said.

Lt. Gov. Fran Ulmer made opening remarks. In meetings around the state she has attended, people are expressing high expectations for the gas project. "People want a piece of this energy." There is potential for low-cost energy and a driver for the Alaska economy, "if it's done right. But there are a lot of ideas out there as to how accomplish this." The important job the governor has assigned to the Council is to listen to people, Ulmer said.

The governor has set standards for resource development, she said. Projects should be based on sound science; prudent management should be assured; and there should be public participation in decisions. "Sound science" requires adequate studies to be done in advance of the project by state agencies, and this will take money. In "prudent management," Canada and its several layers of government will have to be included. "Their resources are affected, too." In Alaska, there will have to be alignment among the several state agencies with statutory authority. The Department of Natural Resources will be the lead agency, insuring coordination among other agencies.

Overall, the gas represents another, bright opportunity for the development of the state's economy, Ulmer said.

Ulmer was followed by State Department of Natural Resources Commissioner Pat Pourchot, who gave a prepared overview of the gas project. *(Note: This standardized presentation was presented at every following public hearing to provide initial information. It is included in Volume II of this report.)*

A presentation by Cambridge Energy Research Associates (CERA) followed, to provide an overview of market trends and opportunities.

(Note: CERA made another presentation to the Council with more updated market assessments later in the summer. The reader may wish to review the more recent CERA presentation made at the Council's public hearing in Anchorage on May 24 and a CERA presentation to the Legislature's Joint Gas Pipeline Committee in late July.)

Despite the very high gas prices of 2000 and early 2001, market conditions may return to more normal levels if there is sufficient replacement of gas in storage through 2001, if there is a cool summer and few hurricanes, along with more supply being made available within the U.S. and from Canada. There could also be lower demand by November and December of 2001, due to the high prices.

This return to more normal conditions for the short term does not change the long-term outlook, however. It is possible that demand may grow to as much as 30 trillion cubic feet (tcf)/year by 2010, from current gas demand of about 23 tcf/year *(Note: later CERA presentations have somewhat altered this assessment.)* However, to support 30 tcf/year demand, an additional 350 tcf of proven reserves must be found. In the 1990s, industry generally replaced production with about 20 billion cubic feet (bcf) per day new production added. This would have to increase to 35 bcf/day to support 30 tcf demand per year. There are other sources of potential new supply. About half a bcf of gas per day is now coming from a new producing area in Canada's Atlantic regions. CERA expects this to increase to 2.5 to 3 bcf/day by 2010. Liquefied natural gas (LNG) is enjoying a reduction in costs, both in LNG gasification in producing regions and LNG regasification in consuming regions. LNG terminals on the U.S. east coast are being brought out of storage status. CERA expects 3 to 3.5 bcf/day of LNG imports into the U.S. east coast by 2010.

As for northern regions, including Alaska and Canada's Mackenzie Delta, CERA expects that up to 3.5 bcf/day could be supplied from these areas by 2019, under several possible scenarios *(Note: see later CERA presentations for more updated assessments.)*

Developers of these northern pipelines face several major risks, the most important that the long-term price must be able to provide a sufficient netback value at the wellhead to not only meet a company's internal minimum hurdle rate for new investment, but also to win the capital allocation battle within a company. Alaska must be seen to be a more attractive investment than new gas developed from the U.S. Gulf of Mexico deepwater regions, the North Sea, offshore areas of West Africa and Brazil, and other new frontier exploration regions. There are also elements of political risk, but these companies are used to working in areas with political risk.

Some of these risks will be shared with end-use customers. Gas producers may share most of the risks to get gas to near the market, but end-users may share risks in gas delivery systems further "downstream." A substantial change in the situation since the last time a major Alaska project was proposed, in the 1970s, is that in these post-regulated gas days the producing companies will now assume the responsibility to get the gas to near the market regions. In the 1970s, when the U.S. natural gas industry was highly regulated, gas pipeline companies were proposing to assume responsibility for building a pipeline and moving the gas to market. In those days, the regulatory structure would have assured a return on the pipeline investment. With the industry now deregulated, this guarantee is no longer available. Producers must now shoulder the burden.

A new development in the gas industry is the collection of changes in LNG business. In recent years there have been several engineering and other technical improvements that have lowered costs of producing LNG. These cost reductions have been driven by major market changes in the LNG trade. In the 1970s, when the world LNG business was first developed, Japan and Korea accounted for 65 to 75 percent of the business. Since LNG import supply was fundamental to the energy security of those countries and the diversification of supply away from OPEC, the facilities were built in a "gold plated" fashion to insure reliability, somewhat in the same way that nuclear facilities are built to insure safety as well as reliability.

Over the years the LNG business has become more "market-based" primarily because there is so much "distressed" gas in regions where LNG is the only practical development option, to the point that producers have sought to improve technology and lower costs to develop new markets and develop stranded gas.

CERA believes LNG costs have been reduced 35 to 40 percent in the last five to 10 years because of these trends.

Another new factor pushing new LNG supply on the market is that fewer countries are now allowing gas to be flared in regions of oil production (where gas is produced along with crude oil). In these cases, producing companies are being pushed to find commercial uses for the gas, and LNG is one of the few options available.

Because of these changes, CERA believes now that the refurbished U.S. east coast LNG import facilities may be able to bring in new LNG for a price in the range of $2.50 per thousand cubic feet (mcf). Because these facilities were built in the 1970s and 1980s (but then written off when gas prices dropped), they can now be operated at the $2.50/mcf level, with a "hefty margin" for the firms involved.

The nature of the contracts for LNG imported into the U.S. east and west coasts may be different than LNG contracts in the existing Pacific trade (to Japan and Korea). Security and reliability are less important (so the facilities will be less "gold plated") and contracts may be for shorter terms, in contrast to very long-term LNG contracts that exist now in the Pacific business.

Despite potential competition from LNG and other new supply sources, the long-term demand for fossil fuel and natural gas will be large, and the ability of existing producing regions, such as western Canada, to supply these needs is in doubt. The 4 bcf/day of new gas supplied from the Arctic should be easily absorbed.

Following CERA's presentation, there were several questions from the Council.

A question was asked about LNG imports into the U.S. west coast.

The response was that northern Baja California is now being considered as a possible LNG import site. Since northern Baja is already a part of the U.S. grid, electricity and gas can be transported into southern California from an LNG plant in northern Baja.

A question was asked that if gas can be brought into the U.S. via LNG for $2.50 per mcf, does this represent a price "cap"?

CERA responded that the $2.50 estimate was for the established, "mothballed" LNG facilities that essentially have zero book value. LNG supply costs are also affected by tanker transportation, in that as distances of tanker transport increase the transportation cost becomes more burdensome. Also, the estimated five to seven years it will take to build new "greenfield" LNG import plants will be a factor.

Because of the time needed for a new plant, there won't be much more than 1 to 1.5 bcf/day in new gas supply on the market in the next five year from LNG imports.

Growth of LNG imports will also be affected by plant siting difficulties within the U.S. However, there are ways around some of these challenges. For example, two new "foreign" facilities being discussed are really U.S. facilities in disguise. These are the facility proposed for Baja California, which will supply southern California, and a facility being discussed in the Bahamas, which will supply Florida by pipeline. In the longer, 10-year perspective LNG could become a serious competitor. The estimate is that gas prices of $2.50 to $3/mcf will be needed to support these new "greenfield" plants, and that is the same price range that is believed required for Arctic gas development.

An important thing to remember is that while there are "hundreds" of trillion cubic feet of new gas potential believed to exist in North America, there are "thousands" of tcf of new gas that will be available from international sources, through LNG imports.

A question was asked about whether CERA had a gas price forecast for 2010.

The response was that a 2010 price forecast will be affected by two factors, one being the long-term price of producing coal (seen as the major competitor for fuel in power generation) and prospects for an economic recession. Generally, CERA is sticking with a long-term price forecast in the high $2 to low $3 per mcf range, by 2010.

Co-chair Frank Brown suggested members of the Council introduce themselves. Brown is a former ARCO Alaska Inc. manager, retiring in 1999, he explained. He has spent eight years of his 30-year career in Alaska, and his last two positions are relevant to work on the Policy Council. One job was as president of a subsidiary, managing production of oil from a field in Long Beach harbor. The company was essentially working as a contractor for the State of California, which owned the field, and regular reports had to be made to the State and the City of Long Beach on market valuations of oil. This experience could help the Council make recommendations on ways to head off future conflicts between the State of Alaska and producers over gas valuation. Brown's second position, and most recent, was in managing development of the new Alpine oil field on the North Slope. This field has not only demonstrated the future potential of the western North Slope region, but involves new land and royalty owners such as Arctic Slope Regional Corp. and Kuukpik Corp., as well as a nearby community (Nuiqsut) and supply of gas to that community.

Co-chair Jim Sampson said he now works with the Alaska Federation of Labor in job training and development, and worked from 1968 to 1986 in construction, with more than a decade of that spent representing construction workers during construction of the trans-Alaska oil pipeline and the North Slope oil fields. After 1986 Sampson spent four years as state labor commissioner, followed by six years as Mayor of the Fairbanks North Star Borough. Having the natural gas pipeline come through Interior Alaska to provide energy, and the jobs it will create, are a real interest, he said.

Mike Navarre said he is president of his family's corporation, which owns and operates eight Arby's restaurants in Alaska. He studied economics and government in university, but his real education in politics came during his service in the state Legislature. His interest in serving on the Council is to help develop a gas project which has the best long-term benefits for Alaska.

Mike O'Connor is president of Peak Oilfield Service Co. His interest in serving on the Council is in helping follow up work on broad state policy from a previous state citizen commission, the Long-Range Fiscal Policy Commission on which two other Policy Council members, Mike Navarre and Al Adams, also served.

Bob Penney, a long-time Alaska businessman, said he has been interested in development of North Slope gas since 1976 and 1977 when he helped created a group, "OMAR" (Organization for the Management of Alaska Resources), to promote an "All-Alaska" gas pipeline (a trans-Alaska gasline to an LNG plant in southern Alaska) as an alternative to the "Arctic Gas" proposal to take gas by pipeline east from Prudhoe to Canada's Mackenzie Delta, the 1970s variant of the northern route being considered today. OMAR later became the Resource Development Council. Penney said many of the same issues from the 1970s are before the Council now, such as the most economic way to move gas to market and whether the state should take its 1/8 royalty gas in-kind.

Ed Rasmuson and his family have been in banking in Alaska for many years and recently sold the National Bank of Alaska to Wells Fargo. "Forty years ago my father told me that in my generation gas will be more important than oil," Rasmuson said. Today the Alaska Highway gas pipeline route creates great opportunities for a gas industry in Alaska, he said.

Jack Roderick said he first came to Alaska in 1954 as a Teamster, and in following years started a petroleum information and scouting service, attending law school, practicing law and engaging in oil and gas lease brokering. Most recently, Roderick wrote "Crude Dreams," a history of the oil and gas industry in Alaska.

George Wuerch, now Mayor of Anchorage, is a veteran oil and gas project manager, now retired, with years of experience in pipelines. In the 1970s and 1980s he was extensively involved in previous efforts to build the Alaska Highway gas pipeline. Besides representing the interests of the Anchorage community on the Council, Wuerch said he hopes to provide continuity with work that was done in the 1970s and 1980s on the gas project, to apply "lessons learned" earlier.

Grace Schaible, a Fairbanks attorney now retired, has been involved for years in Alaska public policy issues. Her interest in serving on the Council, she said, was in helping the State "do it right" this time, as the governor has requested.

Ken Thompson briefly described his background as a senior manager with ARCO Alaska and its parent, Atlantic Richfield Corp. He is now retired and has moved back to Alaska to live and operate his own company, a leadership development and consulting firm. Among positions in ARCO that are relevant, Thompson said his experience as president of ARCO Alaska, the Alaska exploration and production company, and later as head of ARCO's global gas marketing efforts and as part of a U.S. government effort to assist developing countries in gas and power development policy, would be most helpful in his service on the Council.

Rosemarie Maher, CEO of Doyon, Ltd., has been active in Doyon and related Alaska Native affairs for 22 years. In earlier years as president of Northway Natives (in the eastern Interior community) she was extensively involved in efforts in the 1970s and 1980s to build the previously-proposed Alaska Highway gasline. She hoped her knowledge from those efforts would be of benefit to the Council. Doyon has 12 million acres of land and 14,000 shareholders in Interior Alaska who would like to be involved in jobs and training for the gasline, she said.

Carl Marrs is president and CEO of Cook Inlet Region, Inc. and has been with the Anchorage-based regional corporation since it was formed in 1973. His interests in serving on the Council are to help develop a gas industry for the state following pipeline construction, and in helping secure reasonably-priced gas for Southcentral Alaska, because of the possibility that gas reserves in Cook Inlet may become depleted.

Jerry Hood is CEO for Teamsters Local 959 in Alaska and has been interested in development of an Alaska gas pipeline since he served on the board of OMAR in the 1970s, in a previous effort to promote an Alaska gasline. "I hope we can continue the work we started in the 1970s," he said.

Brian Davies is a retired petroleum geologist and manager with BP. "Alaska is our final home, and this is an important project for the future of the state," he said.

Bill Corbus is president of Alaska Electric Light and Power in Juneau, an investor-owned electric utility that has served the Juneau area since 1893. Corbus said he doesn't have direct experience with oil and gas, but feels his experience with the power generation and utility business may be useful on the Council.

Charlie Cole is a long-time attorney practicing in Fairbanks and a former state Attorney General. He was involved in construction efforts related to the trans-Alaska oil pipeline and will work, he said, to get a natural gas pipeline built along the highway so that an economical source of energy can be brought to the Fairbanks area.

Rhonda Boyles, Mayor of the Fairbanks North Star Borough, said she came to Alaska in the mid-1970s during construction of the oil pipeline, as a single mother. Her interest in the gas project now is not only its economic contribution to the state and her own community of Fairbanks, but the social impacts of the project. She is also a small business owner and will bring this perspective to the Council. Fairbanks is positioned well to benefit from the project if it comes along the highway, she noted. "We need not only to do it right this time, but to do it better," she said.

A general discussion among the Council members on process and procedure followed. One suggestion was that the Council adopt a procedure used by a similar oil policy council appointed by the governor some years earlier which combined a schedule of briefings with specified periods for public testimony and comment.

Council member Bob Penney raised the question on how the northern route should be handled. The Council's charter is to consider issues of the highway route, but the producing companies may argue the northern route is cheaper, he said.

Governor Knowles commented that he believed Alaska must support a route option that has the best chance of getting gas to U.S. markets in time to meet the market window, and the timeliness in meeting that demand is important in getting national support for an Alaska gas project. Knowles said he would not have gotten the support of the National Governors Conference for the project had the northern route been the only option being considered. The highway route also makes other options possible, such as, eventually, a pipeline to southern Alaska and an LNG project. "I don't see the northern route as a competitive option."

Alaska Highway Natural Gas Policy Council

AGENDA

Friday, March 23, 2001, 10:00 a.m. to 3:30 p.m.
Anchorage Sheraton Hotel

I. Call to order/opening remarks

II. Presentation from North American Natural Gas Pipeline Group

III. Presentation on the Canadian perspective
Jeff Smith, Senior Vice Pres., Public Affairs, Hill and Knowlton, Ottawa

IV. Break/lunch buffet

V. Presentation on the Federal perspective
Bob Loeffler, Senior Partner, Morrison and Foerster, Washington, DC

VI. Presentation on the State agency perspective
- A. Bill Britt, Coordinator, Joint Pipeline Office
- B. Mark Myers, Director, Division of Oil and Gas

VII. Break

VIII. Council Business – Sampson/Brown
- A. Approve public hearing/meetings schedule
- B. Discuss public hearing format
- C. Discuss subcommittee work

Alaska Highway Natural Gas Policy Council

Full Council Meeting Summary
March 23, 2001, Anchorage Sheraton Hotel

Co-chair Jim Sampson opened the meeting, along with co-chair Frank Brown. This is to be the first of two workshops intended to give Council members a greater understanding of issues around the gas project, Brown said.

Governor Knowles made opening remarks, reporting on recent activities related to the Alaska gas project. The governor testified, along with the governors of Montana and Wyoming, on legislation relating to access to public lands that was before the U.S. House Natural Resources Committee. Knowles commented that one member of the committee, who opposed ANWR opening, remarked, "why don't you folks in Alaska develop your gas first." Not to exclude ANWR, but this signifies the broad support in Congress for developing Alaska stranded gas, the governor observed. Secondly, the governor attended a conference in Calgary, Alberta along with the premiers of Yukon Territory and Northwest Territories, and offered the vision that both the Alaska Highway and Mackenzie Delta pipelines will be needed to supply markets in North America, and that a cooperative approach to do both projects is needed. "Their agenda is no different than Alaska's, in industry development and jobs. They're not in competition with us. We can work together rather than in confrontation." Knowles said the adage of the "early bird gets the worm" applies, because the first projects to deliver gas to the market face the highest probabilities of success.

As the Council took up its workshop agenda, the first to appear were representatives of the North American Natural Gas Pipeline Group *(Note: this group later changed its name to the Alaska Gas Producers Pipeline Team)*, the senior Alaska gas managers for the three producer companies involved. Robbie Schilhab of ExxonMobil Corp; Ken Konrad of BP Alaska Exploration Inc. and Joe Marushack of Phillips Alaska, Inc., who jointly manage the producers' group, appeared before the Council.

Marushack remarked that the time now appears right for commercialization of North Slope gas and that there appears to be a general alignment between Alaska's interests in developing the gas and that of the industry. The Council contains within it considerable skills to analyze issues before the state, including considerable experience in oil and gas and management of large and small businesses. People on the Council have experience in financing businesses and will know that if the producers can develop a good gas project, financing will flow to the venture. "This project is much like others you have dealt with, except the numbers are bigger," he said.

The gas treatment plant that will be built as part of the project will be the biggest of its kind in the world, but it is the smallest part of the overall project. Making steel for the pipeline will require years of effort by steel producers.

Marushack went through a standardized presentation the group has used before other forums in Alaska, highlighting key elements and goals: the large 35 trillion cubic feet (tcf) proven resource and potential for 100 tcf of future discoveries; a rare opportunity of three major oil and gas companies to pool resources with the state of Alaska to develop the project; and the outlook for gas demand growth in the lower 48. The U.S. is now consuming about 62 billion cubic feet (bcf) per day of gas, "but we will have to find another 52 bcf/day by 2010 to replace reserves being produced and meet new demand," he told the Council.

The producers think the lower 48 is the right place to take the gas. The demand for gas (as liquefied natural gas, or LNG) in Asia is expected to grow about 8 bcf/day over the next 10 years in the high case.

Marushack also said there will be lots of competition for the North American market, from deepwater Gulf of Mexico gas, eastern Canada coal-bed methane, tight-sand gas and imported LNG. Very high gas prices of $8 to $10 per thousand cubic feet (mcf) are not good for the Alaska project because they will stimulate lots of competitive new supply. Gas prices in more "reasonable" ranges are better for the Alaska project, he said.

Robbie Schilhab, of ExxonMobil, described the producers' group organization and said the major sources of gas supply for the project, at least initially, were the Prudhoe Bay and Point Thomson gas fields on the North Slope. The group is studying two options, the Alaska Highway route and the offshore "northern" route to the Mackenzie Delta. Contracts are being negotiated with contractors to do engineering and design studies for the large gas plant at Prudhoe Bay; the possible two routes to Canada; on ways of moving the Alaska gas on to lower 48 markets through either expansions of existing pipelines or "new build" pipelines; and on a natural gas liquids extraction plant to be built at some point along the pipeline.

Ken Konrad, of BP, described technical aspects of the studies, including the scope of the gas plant at Prudhoe (it will exceed in size the tonnage of facilities built for all new slope projects in recent years), the high-strength steel needed for the all-buried pipeline and an initial plan to size the pipeline to deliver 4 bcf/day with possibilities for expansion. Construction will be much different than with the trans-Alaska oil pipeline in the 1970s, and will involve automatic welding and automated control systems to achieve levels of high productivity and integrity. It is believed that an Alaska Highway route will require three years of construction. It is possible that the northern offshore route could be built in two years.

Konrad pointed out that the "legacy" of the project will include "upstream" (new exploration and development) as well as "downstream" (gas industry processing, fuel) opportunities for Alaska. The potential 100 tcf of gas on the North Slope is the energy equivalent of 17 billion barrels of crude oil, a considerable resource.

Lee Gorsuch, a Council member, asked for the producers' reaction to Foothills Pipe Lines' comments that a 42-inch pipe size was preferable because existing industry can handle pipe of this size, and a second question involving how expansion of capacity to meet demand in Alaska can be paid for or whether it can be built into the system at the start.

Schilhab commented that the producers are looking first at the overall economic feasibility of the project. Ownership of the project and issues like how expansions will be paid for will come after the project is found to be economic. Konrad added that the group's initial screening studies of pipe size are starting at 48 inches to handle 4 bcf/day, but that the actual diameter could be larger or smaller. If it doesn't cost too much, the bias will be toward larger diameter because it means the system can then be expanded with more compression, which requires less footprint, less environmental impact, etc. than subsequent expansion of pipe.

North Slope Borough Mayor George Ahmaogak asked about possible lost oil production in the Prudhoe Bay field, if there were commercial gas sales.

Konrad replied that this issue is of serious concern to the producers. Oil production is still the lifeblood of the North Slope industry, he said. The producers may be able to make additional investments in Prudhoe to minimize oil losses, such as accelerated drilling, injection of carbon dioxide, "or a whole mix of other projects," he said.

Following the producers, Jeff Smith, of the Calgary office of Hill & Knowlton, a major U.S. public relations firm that is under contract to the State of Alaska, gave the Council a briefing on Canadian politics and how the Canadian government will be influenced on the gas issue. Smith gave a brief description of the structure of Canada's governments and history, underscoring that Canadians have always had a deep attachment to the northern areas and issues that affect the north. It will be dangerous to allow the pipeline issue to become framed as "us vs. them" in Canada, he said, which could easily happen. It is much more effective for Alaska to communicate the commonality of interests in cooperative approaches to development of both Alaska and Canadian gas, as Gov. Knowles is doing, he said.

Smith briefed the Council on status of Native land claims in Yukon and northern British Columbia, which may affect an Alaska Highway route, and mentioned the official Canadian federal policy that the private sector will determine the best routes for northern pipelines, i.e. that it is not a matter for governmental involvement. He described which Canadian federal departments are responsible for different aspects of northern pipelines, and the backgrounds of the ministers heading those departments.

Anchorage Mayor George Wuerch, a Council member, observed that many U.S.-Canada issues were resolved by treaty in the 1970s. Is the treaty now obsolete?

Smith replied the Canadian government recognizes that conditions have changed since the treaty was signed, in technology and the level of environmental assessment, which is now more advanced in both Canada and the U.S. than was the case when the treaty was signed. "The view of Canada's federal government is that its role is to insure a smooth regulatory regime for any pipeline proposal that comes forward," Smith said.

North Slope Borough Mayor George Ahmaogak asked the status of efforts by Mackenzie Delta producers to get their own gas to market.

Smith replied he understands they are working to get their gas to market as soon as possible, and that First Nations groups along the Mackenzie River valley, which would be the route of the pipeline, have formed an organization to work cooperatively with pipeline developers.

Jack Roderick, a Council member, asked about how NAFTA (North American Free Trade Agreement) might apply to the gas project and whether other trade issues might affect the project.

Smith replied that there is a major dispute between the U.S. and Canada over Canadian lumber exports and that there are some in Canada who argue that "gas should be held hostage" until lumber and other issues are resolved. However, the prime minister has consistently said that he will fight the U.S. if there are trade disputes, but that energy will not become involved. The prime minister is keenly interested in President Bush's notion of a North American energy regime and will not allow energy to be dragged into disputes over other trade issues, he said.

Bob Loeffler, a senior partner in the Washington, D.C. firm of Morrison and Foerster, gave the next presentation to the Council.

Loeffler first outlined the major players on the federal level: the Department of the Interior, which will issue the ROW lease; the Department of Energy, which has less clear jurisdiction but is the policy arm of the Federal Government on gas pipeline issues; the Federal Energy Regulatory Commission (FERC), which has jurisdiction over gas pipelines; and Congress, which may or may not play a role with legislation.

The two federal departments will not be fully staffed at the senior levels for several months, due to the recent change of federal administration. At the moment, FERC has only three of its five board positions filled and the President may soon replace the sitting chair. In Congress, two pieces of energy legislation are in the Senate (one introduced by Senator Murkowski, the other by Senator Bingaman), but neither have provisions specific to an Alaska gasline.

Mr. Loeffler continued by saying that there is no discernable opposition in D.C. to developing Alaska's North Slope gas, but it is too early to find consensus on a route or an applicant. However, there is a fair amount of support, due to historical and logical reasons, for a southern route.

The outgoing FERC chair (the chairmanship passed from a Democrat to a Republican in January) released a report identifying issues that the federal government will face with an Alaska gasline project. This report is more of a FERC staff report than a Commissioners' report, and the new chair has not yet read the report. The report does not conclude whether or not Congress meant to apply the benefits of the Alaska Natural Gas Transportation Act (ANGTA) to projects contemplated so long after the original decision. After all, there have been many changes since 1976: wellhead prices are no longer regulated; there would be different economic impacts to the country; environmental issues have changed—the judicial limitations placed on appeals couldn't apply to environmental legislation passed after ANGTA, such as the Endangered Species Act.

ANGTA created special procedures to avoid the lengthy FERC comparison and approval hearings. ANGTA remains on the books and only small portions of it have been repealed, such as the Office of the Federal Inspector (OFI). Under Section 9 of ANGTA, all federal agencies were directed to expedite issuance of permits related to ANGTS and were deprived of authority to approve terms and conditions that would compel a change in the basic nature or general route of the pipeline project.

ANGTA is relevant today in that it either still applies or is a model for new federal legislation that would coordinate, centralize and expedite today's project.

Loeffler thinks FERC can't and won't act until some application has been submitted to them. Do they have jurisdiction to accept an application other than the one chosen by the President in 1977? FERC believes so, but there is as yet no definitive answer to that question.

Loeffler mentioned ongoing international considerations. The 1977 treaty between the U.S. and Canada was based on a timetable that projected the pipeline would be in operation by the beginning of 1983. Does this treaty still apply?

There are many unanswered questions, Loeffler concluded, but the prospects for an Alaska gas pipeline project have never looked so good.

Council member Al Adams asked can FERC jurisdiction be bypassed by using a port authority concept for the project?

Mr. Loeffler stated that the federal government doesn't give up jurisdiction readily, and while there is an historical example of a FERC exemption applied to a gas pipeline within the boundaries of one state (the Hinshaw exemption), he has not seen a legal argument for total exemption.

Anchorage Mayor George Wuerch, a Council member, asked if the Northwest project and partners had federal and state ROW leases and, if so, are the leases transferable to private or publicly owned authorities?

Mr. Loeffler said he hasn't looked at that recently, but recollects that there is provision for transfer of federal ROW leases within the terms and conditions of the President's Decision.

Mayor Wuerch followed up by asking if the OFI concept is likely to be used again?

Mr. Loeffler replied that the position has been abolished and that he thinks this administration would be sensitive to the State of Alaska's concerns about the OFI.

Council member Charlie Cole asked if the Yukon Pacific Corporation's (YPC) permits are readily available.

Mr. Loeffler replied that YPC owns a separate series of conditional permits. A number of them must be renewed or conditions must be met. It would be an overstatement to say that the YPC project is "ready to go".

Lee Gorsuch, a Council member asked if there is any language in ANGTA about local access to gas.

Mr. Loeffler stated that Section 13B of ANGTA gives the State of Alaska authority to withdraw its royalty gas and mandates FERC issue authorizations necessary to effectuate such withdrawal.

Jack Roderick, a Council member, asked if the U.S. needs a new treaty with Canada.

There may be need for new federal legislation, Mr. Loeffler stated, and possibly a new treaty or an update of the letter of agreement between the two countries.

Lee Gorsuch asked if Foothills' ROWs in Canada are valid. Mr. Loeffler didn't know, as he doesn't practice in Canada.

Council member Jeff Feldman asked Mr. Loeffler to contrast the amount of time needed for regulatory approval for a highway project versus updating and completing conditions of the YPC project. How much further ahead are they, if at all?

Mr. Loeffler first replied that any project must meet the test of market—a project may have every permit but still not pass the "test of the market". The producers estimate three years for permitting a highway project, although Mr. Loeffler is hopeful it can be reduced to 2 years. Completing the conditions of YPC's project would take a year, Mr. Loeffler guessed, depending on the response of regulators.

Charlie Cole asked if Foothills has any binding and enforceable permits or paramount rights for a pipeline within or outside of Alaska.

Mr. Loeffler replied that no one knows. The President selected the Northwest Partnership to build the system, and that certificate can be transferred. If the certificate is still viable, then Foothills has those rights. The FERC report suggests that those rights are not exclusive, but an argument could be made either way.

Lee Gorsuch asked what restrictions there are under FERC jurisdiction that would limit the State's ability to pass terms and conditions on taking off gas, or other things the State determines to be in its interest.

Mr. Loeffler answered that the FERC certificate gives the holder a right to Imminent Domain over private lands. His firm has argued since 1975 that it gives no such right over state lands. If the Imminent Domain decision stands, he continued, it is arguable that there isn't a federal presumption of terms and conditions over state lands. However, Mr. Loeffler doesn't think the federal government would preempt the State with respect to state ROWs.

Jack Roderick asked if the State would have authority to regulate the tariff inside the State.

Mr. Loeffler replied, "I believe the answer is no."

Bill Britt, the state pipeline coordinator, described the functions of the state-federal Joint Pipeline Office (JPO), which includes several state and federal agencies who function together to oversee pipeline operations and review new applications. State agencies within the JPO have formed a group within the office working solely on the gas pipeline, and it is believed the federal agencies will similarly form a subgroup to work on gas, joining the State. Of the federal permits required, the Environmental Impact Statement is likely to take the most time. The streamlined EIS for lease sales in the National Petroleum Reserve took 18 months, so a gas pipeline EIS would require a similar period, or longer. Among State authorizations, the State pipeline right-of-way lease will require the most time, possibly nine months. State air quality permits (the State has air quality jurisdiction under the federal Clean Air Act) will also take time. Another function of state and federal agencies in the JPO is the review of engineering and technical data provided in support of a pipeline application.

It is important for agencies to work as much as possible with potential applicants for pipeline projects before the application is submitted so that the application is as complete as possible when it is submitted. This will speed the authorization process. What is unusual with the gas project is that while the JPO's functions on trans-Alaska oil pipeline oversight are paid for by the TAPS system, there is no such payment mechanism, as yet, on gas projects. There are several groups who are working on new or renewed permit efforts on gas projects, including the producers' group, Foothills Pipelines and Yukon Pacific Corp. The state is negotiating cost-reimbursement agreements to cover most expenses related to these pending applications, but it is appropriate that some costs should be paid by the State, from State general funds. About 10 percent of the JPO's funds come from appropriation of general funds from land rentals for pipeline rights-of-way, but this is the first time that the office has been faced with a great deal of work related to anticipated new applications. This is why increased general fund appropriations from the Legislature have been requested. Britt warned that recruiting is a major challenge for his group, in the face of increased demand for engineers and other specialists by industry. The JPO will also contract a lot of its work to consultants, but some types of work are more appropriately done by agency staff.

Charlie Cole, a Council member, expressed concerns about the state agencies in JPO having the resources and staff to keep up with the project and allow it to stay on schedule.

Mark Myers, director of the Division of Oil and Gas, briefed the Council on his division's outlook for future gas potential and several study projects underway related to gas development. The estimated 31 to 35 tcf of proven undeveloped gas resources of the North Slope represent 20 percent of the nation's proven gas reserves, he said. Cook Inlet has about 2.5 tcf of remaining proven reserves.

Currently the division is gathering information in four areas: potential in-state demand for gas; royalty gas valuation; effects of gas production on the Prudhoe Bay and Point Thomson reservoirs (effects of gas in oil production in Prudhoe is a major concern); and an assessment of the long-term potential undiscovered gas resource. A $50,000 "fast-track" appropriation by the Legislature on the gas drawdown reservoir effects study is underway and will be completed by the end of the year. This will lead into a longer-term, $500,000 study of reservoir effects by the Alaska Oil and Gas Conservation Commission.

The potential for new gas discoveries is very good because geological conditions in many areas, such as the Brooks Range foothills, are more conducive for gas than oil. Also, gas can be developed from lower quality reservoirs than is usually the case for oil. Thus, there are many more potential reservoir targets for gas. The coastal plain of the Arctic National Wildlife Refuge also has potential. "We know it's one of the best unexplored areas for oil, but parts of the area also have great potential for gas. It could be a world-class gas belt." There are also unconventional gas resources, such as gas from hydrates and coal beds.

Bob Penney, a Council member, asked how much more gas could be used in Alaska, and what other industries could develop if there were reasonably priced gas.

Myers said that the basic issue will be the delivered price of gas, which derives from the economics of the pipeline. The division's demand study now underway, funded at $75,000, is a screening study of potential demand and will give some indications of answers. Of the approximate 225 billion cubic feet of gas from Cook Inlet used annually, about 25 percent is used for energy, for space heating and production of electricity, and 75 percent is used for industrial purposes, either in fertilizer manufacturing or in the making of liquefied natural gas for export.

Alaska Highway Natural Gas Policy Council

AGENDA

Thursday, April 5, 2001, 10:00 a.m. to 5:30 p.m.
Anchorage Sheraton Hotel

I. Call to order/opening remarks

II. Presentation from Alaska Gasline Port Authority

III. Presentation from Foothills Pipe Lines Ltd.

IV. Lunch break

V. Presentation from LNG Sponsor Group

VI. Presentation from Yukon Pacific Corporation

VII. Council Business

VIII. Subcommittee Session I
- A. State's Royalty Share – Bill Corbus, chair
- B. Access to the gas/In-state gas consumption – Ken Thompson, chair

IX. Subcommittee Session II
- A. Alaska Hire/Buy/Build – Mike Navarre, chair
- B. Federal/International Action – Charlie Cole, chair
- C. Environmental Considerations – Peg Tileston, chair

Alaska Highway Natural Gas Policy Council

Full Council Meeting Summary
April 5, 2001, Anchorage Sheraton Hotel

Co-chair Jim Sampson called the meeting to order.

Gov. Knowles briefed the Council on recent developments in the national energy situation. The outlook is for continued shortages of electricity in parts of the country and high prices for natural gas. There have been no significant changes in the situation.

The governor attended an energy conference in Houston also attended by Canadian leaders, which was heavily attended due to high interest in the energy situation. Knowles' message to the conference was that Arctic gas - Alaskan and Canadian - can help meet the nation's energy needs. Alaska is not in competition with Canada, because new gas from all sources – the Arctic, western Canada, East Coast Canada, Gulf of Mexico and LNG imports - will be needed to meet the expected demand.

Knowles also told the Council that Senate President Rick Halford and House Speaker Brian Porter have agreed to become members of the Council.

Alaska Gasline Port Authority:

Dave Cobb, former Valdez Mayor and member of the Port Authority board, gave the presentation.

The Port Authority was created under Alaska statutes allowing separate port authorities to be formed by municipal governments. Voters in the City of Valdez, Fairbanks North Star Borough and North Slope Borough approved its creation in October 1999.

Cobb said that three guiding principles for the Authority include creation of jobs, providing gas to Alaskan communities and helping stabilize the state economy by helping commercialize stranded North Slope gas. The approach, using tax-exempt public debt financing for a portion of the project, would lower costs and dramatically increase the economic viability of a large gas project, and maximize benefits to both Alaska and the producer companies.

The three municipalities forming the Port Authority each contributed $100,000 to its startup costs, Cobb said. Yukon Pacific Corp. made a $250,000 contribution, along with a $75,000 contribution by Bechtel Corp, he said. The authority has a Memorandum of Understanding with Bechtel, under which the company did a "ground up" (i.e. original, not built on previous work) construction cost estimate, an effort that involved about 55,000 manhours of work. Bechtel has about $5 million to $6 million invested in this effort, which involves the use of state-of-the-art pipeline technology, Cobb said. The international financial consultants Taylor-Dejoung developed an economic model based on Bechtel's cost estimate.

Two other accomplishments of the Authority include obtaining a ruling from the Internal Revenue Service that the Authority is a public corporation exempt from federal income tax, and an assurance from the Federal Energy Regulatory Commission (FERC) that a gas project built by the Authority would not be subject to FERC review, Cobb said.

The Authority contemplates financing 100 percent of the project and distributing net revenues on a formula providing for 60 percent of revenues paid to the State of Alaska, 30 percent to all Alaska municipalities and 10 percent retained by the Authority and the three municipalities that formed it. The distribution to municipalities is intended to replace state revenue-sharing, which has declined substantially in recent years. The minimum payment to any community, no matter how small, is $50,000 per year, Cobb said.

By taking advantage of exemptions from many federal, state and local taxes, a gas project built by the Authority would result in $2 billion to $3 billion in revenues to gas producers over what a privately-built project would produce, and an additional $1 billion to the State of Alaska.

Valdez has a history of promoting similar pubic/private partnerships, Cobb said. During construction of the trans-Alaska oil pipeline in the 1970s, the City of Valdez issued revenue bonds to finance parts of the Valdez Marine Terminal. The city is the owner of these facilities, Cobb said, and both Valdez and the pipeline owner companies have realized substantial benefits from the arrangement.

Questions from the Council:

A question was asked about assumptions of gas volume and throughput.

Cobb replied that the Authority believes in the "Y" concept, with one pipeline built through Interior Alaska to the lower 48 and a second pipeline branching off to an LNG plant on the southern Alaska coast. The project envisioned by the Authority would carry 6 billion cubic feet of gas daily from the North Slope to the "Y" junction in the Interior. Three billion cubic feet of gas daily would then be shipped on to the lower 48, and three billion cubic feet of gas daily shipped to the LNG plant through the second pipeline.

A Council member asked about guarantees for the bonds.

Cobb replied that the Authority would guarantee debt issued for the project. If the bond market doesn't believe the project is feasible, the bonds won't be purchased, he said.

He stressed that the Authority would own the project but would contract for construction and operation. Also, while the most financially advantageous project involves the Authority actually purchasing gas from the producers and selling it, the producers could also contract to ship their own gas through a gas pipeline owned by the Authority. The Authority could also own part of a project. For example, if the producers want to retain ownership of a pipeline to the lower 48, the Authority could build the spur pipeline to southern Alaska. "We believe the Port Authority can fit in anywhere. There are advantages without full-scale involvement," Cobb said.

A Council member asked for more information about the allocation of revenues, and a comparison of how the state and its communities benefit under the status quo, retaining their own full taxing authority (such as State corporate income tax), and the tax-exempt, revenue-distribution concept proposed by the Authority.

Cobb replied that this analysis has been done and that he would provide it to the Council.

A Council member asked why the State couldn't do what the authority proposes to do, with similar advantages.

Cobb replied that financial consultants had advised that if the State were the financing entity, bond buyers would very likely ask for backstop guarantees from the Alaska Permanent Fund. Because the Port Authority is an independent public corporation, with, under state law, no guarantees required from either the municipalities involved or state government, a bond buyer would have to look only to the project, because the Authority has no funds to guarantee bonds.

An observation by a Council member was that guarantees from the producers would likely be involved, in the form of long-term contracts to ship gas.

Another Council member observed that until very recently, producers were not involved in pipeline ownership in the lower 48. The take-or-pay contracts they signed served as guarantees to independent third parties building and operating the pipelines. This has changed in the last 20 years. Producers have become involved in riskier domestic pipeline projects built into new areas to control costs. Overseas, a model of part government and part private ownership has evolved, with governments desiring an involvement so as to be able to participate in the setting of tariffs. Producers become involved for the same reasons, and to control costs.

Another motive for producer involvement is to enjoy the financial benefits of an equity position in a pipeline, it was explained. Rate of return on a pipeline investment is typically lower than from a producing property, but it is constant, without the ups and down of production revenues (due to price volatility) and is a good source of steady cash-flow.

Foothills Pipe Lines, Ltd.

John Ellwood, vice president engineering and operations, gave the presentation.

Foothills is a joint-venture company formed by TransCanada Pipelines Limited and Westcoast Energy, two of Canada's largest pipeline companies, to participate in an Alaska natural gas pipeline project when it was first proposed in the late 1970s.

Ellwood sketched the history of the company's involvement in the Alaska gas pipeline project. Foothills was originally formed to build the Canadian portions of the Alaska Natural Gas Transmission System (ANGTS.)

Meanwhile, two "pre-built" portions of the system, from western Canada to the U.S. midwest and Pacific Northwest, were built by Foothills and are in operation today. As for the Alaska portion, as members of the ANGTS consortium withdrew from the project Foothills purchased their interest. "We saw real value in the Alaska Natural Gas Act, its Canadian counterpart and the U.S.-Canada Treaty because they will get a project done quickly. That is why we devoted extensive efforts to keep the permits alive."

Today Foothills is the operator of the ANGTS project, which has permits and rights-of-way for a gas pipeline along the Alaska Highway through Alaska and Canada. Foothills has kept all of the permits for the system in good standing, Ellwood said. The permits will have to be updated to reflect different volumes of gas and the new technology being incorporated, but the updating can be done without difficulty, he said.

The pre-built parts of the system were a gamble at the time, Ellwood said. They were built because there was no assurance that the northern part of the project would be completed (it wasn't). The pipelines were built oversized for the gas then available for shipment, and the Canadian government sought an assurance from the U.S. government that the Alaskan part would eventually be built. The assurance was given.

However, gas production from western Canada has expanded considerably and today the pre-built sections are not only full, but have been expanded five times, each expansion incorporating the latest in new technology, Ellwood said. The pre-built pipelines now carry 3 billion cubic feet per day of gas, roughly 5 percent of U.S. gas consumption.

Today the legal structure of the U.S. presidential decision, laws passed by both the U.S. Congress and Canadian Parliament, and the U.S.-Canada treaty remain in full force, Ellwood said. A 1977 conditional certificate issued by the Federal Energy Regulatory Commission also remains in effect, he said, as does a right-of-way across federal lands in Alaska and a conditional state right-of-way.

These do not give Foothills a perpetual franchise but they do give the ANGTS project a priority over any competing applications, he said.

Some are suggesting that Foothills must use only the original design specified in the existing permits, Ellwood said. "We have researched this carefully, and it is not the case. Section 9 of the (federal) Alaska Natural Gas Act gives FERC the authority to amend our certificate, as long as we don't change our basic route or the nature of our project," he said.

Another change since the 1980s was that the Office of the Federal Inspector for the ANGTS project, originally within the Department of the Interior, was moved to the Department of Energy. Ellwood said the Secretary of Energy has given assurances that the functions of the Federal Inspector would be carried out by this office should the project be revived.

A key advantage of the existing laws is that they provide for limited judicial review. "That is a very valuable asset," Ellwood said.

The company has a "pending" right-of-way application with the State of Alaska to cross state-owned lands. Foothills is now in discussion with the State on renewing work on that application.

On the Canadian side, the company has a Certificate of Public Convenience and Necessity issued by Parliament, which means only that body can revoke the certificate. Also, a right-of-way has been established across Yukon Territory which is not subject to land claims by First Nation groups. All 14 First Nation groups have signed an agreement recognizing the right-of-way, Ellwood said.

What the company does not yet have is a commercial agreement with the North Slope producers, he said, and Foothills is now devoting its energies to achieving that. "We anticipate the producers will want some part in ownership and control," Ellwood said. That isn't a problem. "We want to be part of the solution, not a problem," for the producers, he said.

The key message that Foothills would like to leave with the Council, Ellwood said, is that the expedited regulatory review system established under the existing laws and treaty constitutes a valuable asset for Alaska and the producers, as well as for Foothills, because it would allow a gas pipeline project to get through red tape very quickly.

A Council member asked if Foothills, as a Canadian company, will seek U.S. companies as partners.

Ellwood answered that his company is open to new partners but that the first priority is to get a commercial agreement with the producers.

A Council member asked the status of a lateral pipeline to the Mackenzie Delta provided in the 1980s laws and treaty agreements.

Ellwood responded that the existing laws and treaty do provide for a spur pipeline along the Dempster Highway that would join the ANGTS pipeline near Whitehorse, Y.T. That pipeline was planned when there was a moratorium on pipelines along the Mackenzie River valley because of unsettled Native land claims. Those claims are now being resolved, and communities along the Mackenzie now support a pipeline. Oil and gas companies with interests in the Mackenzie Delta are now considering a stand-alone pipeline south along the Mackenzie, so the Dempster Highway route is no longer needed, he said.

A Council member asked why the Alaska Highway "southern" route has advantages over the "northern" offshore route, if that route is shorter.

Ellwood responded that Foothills conducted a 50,000 man/hour study of the northern route and concluded that it would wind up costing about the same as the southern highway route because of potential problems with ice scour and trenching in the offshore segments, and problems of where to locate compressor stations if an onshore site is unavailable in wildlife refuges in northeastern Alaska (ANWR) and Yukon Territory. The southern route, although longer, has less risk. Also, availability of existing road infrastructure is a big asset.

Ellwood added that an additional problem facing a northern route is the commercial problem of sizing the pipeline to carry an unknown amount of gas from the Mackenzie Delta that is unproven (undrilled) at this point. In contrast the North Slope gas is a proven, confirmed resource. The problem is financing a northern route pipeline with enough capacity to carry both Alaskan and Mackenzie gas without the Mackenzie reserves defined to the point where contracts for gas shipment can support the additional investment.

A Council member asked about available capacity in pipelines from Canada to the U.S. that could connect with an Alaska pipeline in western Canada.

Ellwood responded that the existing pipeline grid in Canada has about 1 billion to 1.5 billion cubic/ feet per day unused capacity. Even if that capacity is not available by the time an Alaska pipeline is built (production from Canada is expected to increase by that time) the pipeline grid can be expanded, as it has before, or a new pipeline can be built.

Alaska North Slope LNG Project

Steve Alleman, project manager, made the presentation.

Alleman reviewed his group's progress to date in its work on an LNG export project. Phase one, completed last fall, involved $12 million expended in conceptual engineering, and commercial and market feasibility work.

This was successful in that a scaled down project was defined that would produce a volume of LNG (7 million tons/LNG annually) that might better fit into what the sponsor group feels is the available market in the Pacific. The project can then be expanded as the market develops.

However, even a scaled-down project was not deemed to be cost competitive, Alleman told the Council. The group's current key focus, in a $3 million phase two effort, is to find potential cost savings through synergy with the lower 48 pipeline project being planned by the North Slope producers. This would involve the "Y" concept, or a pipeline spur connecting in Interior Alaska that would carry gas to a southern Alaska LNG plant. This would shorten the distance of new "stand alone" pipeline. The lower capital cost might improve the project's economics but whether it would be enough is still uncertain.

Alleman told the Council that his group expects to conclude internal studies on an environmental assessment of the Cook Inlet route by the end of April, and to have cost estimates for a project that links with the lower 48 pipeline as early as mid-June or July.

A Council member asked about any benefits of public financing or public ownership.

Alleman said his group's analysis so far is that no compelling advantage is presented in a "public/ private partnership" with an entity like the Alaska Gasline Port Authority (meaning a project partly owned by both industry and the Authority). He added, however, that full public ownership of a project that can fully realize federal tax advantages may be different. Further discussions with the Port Authority are planned.

To illustrate the challenges the LNG project faces, Alleman showed a slide to the Council that compared estimated capital costs of other proposed LNG projects, including proposed expansions and new "greenfield" (entirely new) projects, like Alaska, that are competing for the expected new demand in Asia. Figures in the chart are based on published information, he said.

The chart shows the average capital cost among the competing projects, per million tons of LNG delivered yearly, range between $225 million to $250 million per million tons of annual LNG delivery. The estimated cost of the Alaska project, with a stand-alone pipeline (i.e. without the link to the lower 48 pipeline) ranges between $610 million to $790 million per million tons delivered. The 800-mile pipeline (in the case of a stand-alone pipeline) is about $300 million per million tons per year, or

40 percent to 50 percent of the project total unit cost. The pipeline is a huge challenge for the project when compared with its competitors, which are at tidewater, Alleman told the Council.

(Note: Three of the LNG sponsor group's four members are involved in lower 48 pipeline studies: BP, Phillips and Foothills.)

A Council member asked why the existing Phillips LNG plant at Nikiski couldn't be expanded, in a case where a pipeline went to Cook Inlet.

Alleman replied the group continues to look at that, and has not ruled out exploring possible synergies there.

A Council member asked about the economics of ocean shipping of LNG. With Phillips looking at importing LNG from Australia to the U.S. West Coast, wouldn't Alaska, with a shorter shipping distance, be as or more competitive?

Alleman replied that his group had compared published estimates on "total cost of service" (including shipping) from Australia to California, and penalized the Australian service with the need for additional ships because of the longer distance. The Alaska project, in shipping LNG to California, still wasn't as competitive, he said, primarily because of the 800-mile Arctic pipeline that an Alaska project must overcome.

A Council member observed that some of the existing LNG projects in southeast Asia can be more competitive than a new Alaska project, even with a longer shipping distance, because the LNG tankers are already built and in service. He asked for more information on the total cost of service of supplying LNG from Australia compared with estimates for an Alaska project, which is one quarter of the distance.

Alleman said he would get the information to the Council on shipping distances.

Yukon Pacific Corp.

The presentation was made by Jeff Lowenfels, president and CEO of Yukon Pacific.

Lowenfels said there are three "myths" about an LNG project, that there is "no market," that LNG is not an option and that the overland (lower 48) project is the only option. Alaska gas does face challenges because of its remote location and competition from other LNG projects, so any project from Alaska must be big to achieve economies of scale.

Despite all the work on gas over the years, the producers were not in a position to sell gas until June 2000, when the realignment of ownership in the Prudhoe Bay field changed conflicting priorities among the field owners, mainly three major producing companies.

Yukon Pacific has done extensive work on permits over the years and has secured the major "deal-killer" permits, Lowenfels said. In comparison, it will not be easy to permit the Alaska Highway route with the existing requirements of U.S. and Canadian laws on a highway pipeline, he said.

As for market demand, several studies, including independent U.S. groups like Standard and Poors, feel Asian demand for LNG will grow sharply. Estimates by private industry within the three Asian nations that are most likely markets for Alaska gas, Japan, Korea, and Taiwan, show strong future demand. Government estimates are lower because they assume more power will be supplied by nuclear plants, an assumption private industry discounts, Lowenfels said. India and probably China are probably not markets for Alaska because those countries can be supplied more economically by producers in Southeast Asia and the Middle East, but growing demand for LNG in both countries will take supply off the market, indirectly helping Alaska.

Lowenfels showed a chart showing results of two studies by engineering groups, one by Willbros Engineering and Micheal Baker Jr., and a second by Kellogg Brown & Root and Air Products and Chemicals, Inc. The estimates showed a "startup" project delivering 9.2 million tons/year of LNG could be built for $6 billion (2000 dollars), expanded to 13.8 million tons/year with an additional investment of $1.1 billion, and expanded again to 18.4 million tons/year with an additional $1.2 billion investment.

The total "cost of service" to Japan, including shipping, at a "low" case of $1.99 per million British Thermal Units (Btu) delivered to a "high" case of $2.91 per million Btu delivered. This appears attractive in the context of estimates by Tokyo Gas that it will contract LNG for $3.88 per million Btu between 2005 and 2010. "Our numbers work," said Lowenfels.

In discussion following the presentation, Lowenfels said YPC was shocked to discover that the assumptions used in the Purvin & Gertz (a consulting firm relied on by industry and the State) study for LNG relied on generic "off the shelf" data rather than estimates compiled by YPC itself. The effect is to understate the benefits of an LNG project, Lowenfels said. YPC is now discussing the report with Purvin & Gertz, and is hopeful that a more up-to-date "apples to apples" comparison can be made.

Lowenfels urged the Council to question why the "highway" is its mandate. Yukon Pacific has been working on an LNG project for many years, but was not consulted, he said. He said he didn't know what information the Administration relied on in making its decision in favor of the highway route, but he suspected it was the Purvin & Gertz study.

A Council member observed that he has always favored access to multiple gas markets, since individual markets will always cycle up and down. He asked if the lower 48 pipeline now being planned helps Yukon Pacific's project. Why doesn't YPC plan a smaller project, sized to fit the market, building off the larger pipeline?

Lowenfels replied that YPC had always built in an assumption of size that would allow a pipeline to the lower 48 to branch off at Delta. He said his company also favors some form of transparency (clear, predetermined procedures) for gas offtake, if not public ownership.

A Council member asked if YPC sees a higher wellhead price for gas from an LNG project, why Phillips (lead company in the industry LNG consortium) doesn't also see that.

Lowenfels replied that individual companies may have other projects with higher rates of return, fewer partners to deal with or complexities in putting a project together, or combinations of all those. There may be other factors affecting Phillips' decision to participate in a project to import LNG from Australia rather than Alaska, such as a possible deadline on a concession in Australia.

A Council member replied that it seemed odd that Phillips, with an ownership interest in Alaska gas and a motivation to commercialize the asset, doesn't see a return similar to than in Australia, which is more distant.

Lowenfels replied that projects compete for funds, and investments go to the project with the highest return and fewest headaches. "I think that's what is going on here," he said.

A Council member asked if there wasn't a danger in proceeding on a parallel track with the pipeline to the lower 48.

Lowenfels replied that he has no confidence the lower 48 pipeline will really proceed. Even the companies involved say they're not sure they really have a project, he told the Council. That is why YPC is continuing to work on its own project. "We hope it (the lower 48 pipeline) does go, because we can easily piggyback on it. But we can't stop our work to wait for them," Lowenfels said.

The lower 48 pipeline, and the governor's decision to support it, has been a setback for Yukon Pacific, however. It sends a message to potential buyers in Asia that Alaska gas might not be available. That is why the senior gas manager from Tokyo Gas came to Alaska a few weeks previous, to tell state and community leaders that his company is very interested in North Slope gas.

Lowenfels also observed that discussion of a 6 billion cubic feet/day gas throughput for a project (in the Port Authority's case) is too high. It would deplete the only current North Slope reserves in production in nine and a half years. Lowenfels said that only current production is available today. There is no assurance any other fields will be opened and hence only the 21 trillion cubic feet left in the Prudhoe Bay Unit is available for any project. YPC's project assumes a lower throughput rate of two billion cubic feet/day, which can be sustained for a much longer time.

A Council member asked Lowenfels' opinion of a gas reserves tax (a state property tax) on undeveloped gas on the North Slope. (The proposal has been made by a state legislator.)

Lowenfels replied that the idea was interesting and may be appropriate.

Alaska Highway Natural Gas Policy Council

AGENDA

April 18, 2001, 5:00 p.m. to 9:00 p.m.
Chena River Convention Center, Fairbanks

I. Community Reception

II. Opening remarks from Mayor Rhonda Boyles

III. Opening remarks from Governor Tony Knowles

IV. Presentation from Commissioner Deborah Sedwick

V. Presentation from Foothills Pipe Lines Ltd.

VI. Presentation from Ken Thompson on "The Hub" concept

VII. Public testimony

Alaska Highway Natural Gas Policy Council

Fairbanks Public Hearing Summary
April 18, 2001, Chena River Convention Center

Co-chair Jim Sampson opened the hearing. Brief presentations were made by Deborah Sedwick, Commissioner of the Department of Community and Economic Development, on an overview of the proposed gas projects; Council member Ken Thompson on his proposal for gas trading "hubs" in Alaska with pre-arranged agreements for access to natural gas; and Curtis Thayer, of the gas producers' project group.

Members of the public were invited to speak:

Buzz Otis, representing the Fairbanks Chamber of Commerce gas committee, suggested a major issue the Council should focus on is pricing of gas, clearly defined access rights. A small business, a propane distributor, for example, should be able to gain access without onerous rules being applied. A pricing mechanism should be established that is the North Slope netback (wellhead price) price plus cost of transportation to Fairbanks.

Nadine Hargesheimer, representing the Fairbanks North Star Borough, told the Council that Fairbanks is a non-attainment area on carbon monoxide but the Borough is working closely with the state Department of Environmental Conservation to get the Environmental Protection Agency to "stop the clock" on sanctions. The Borough will do everything in its power to make sure provisions of the Clean Air Act, as they apply to Fairbanks, do not impede construction of a natural gas pipeline.

The Borough is concerned, however, with the enactment of state law by the Legislature which allows the State to negotiate away municipal taxing powers on a gas pipeline. Borough assembly members are uncomfortable that the State could use municipal taxes as a bargaining chip, without any direct participation by municipalities under the terms of the law.

Bert Bell, president of Ghemm Co. and head of the Associated General Contractors, expressed concern about sufficient manpower for a pipeline construction project. It's important that the pipeline's labor needs be known as soon as possible. It may be possible to spread out other projects so that all the work does not come in one peak period.

Training programs have to be underway very soon, as it takes four years to train to journeyman skills in many crafts that will be needed on the pipeline. The trans-Alaska oil pipeline had a tremendous impact on the labor force. "It killed the rest of the industry for about five years," Bell said.

Steve Ginnis, president of the Tanana Chiefs Conference, told the Council his organization represents communities across an area 235,000 square miles and 17,000 people. The nonprofit manages 220 programs and employs 500 people.

The natural gas pipeline project is being watched closely by tribal groups. The gas represents, in energy value, about 50 percent of the original recoverable reserves in the Prudhoe Bay field. The pipeline project has the potential to do a lot of good if it is done right.

It could employ a lot of people, and it's important that it be done right. The three to five years of construction have the potential for an enormous economic boost to the region's infrastructure, including schools and health facilities. Thirty years ago Alaska Natives supported the first pipeline and we support this one, too.

However, the route does cross Native lands. It will run for miles through our neighborhood. We will want assurances of planning, performance criteria and the dissemination of information. It is important that our villages be represented on the planning committees. We would also like the pipeline to serve our communities, to help reduce energy costs. The crossing of the Yukon River represents an opportunity to transfer the benefits upstream and downstream, improving living conditions in the region.

Jay Quakenbush spoke, representing the Fairbanks building and construction trades unions, 14 unions representing 9,500 experienced construction workers that the unions bring to the table. We feel this resource must come through the Interior so Fairbanks can make use of its energy. We feel the best way to promote Alaska hire is to promote and negotiate a Project Labor Agreement so that hiring is done through the halls these unions represent. Each union gives preference to Alaskan workers. Nine of the 14 unions in the council are headquartered in Fairbanks, and the other five are headquartered elsewhere in Alaska. It's the best way to insure that this money stays in Alaska and creates careers for local people.

No other organization has reached out to help train Alaska Natives like unions have done. We have demonstrated this through projects like the recent Marriott Hotel construction in Fairbanks and the Alaska Native hospital in Anchorage.

We feel we can supply a significant Alaska workforce but we need a commitment to start training. It takes 8,000 hours of field work and 10,000 hours of classroom time to produce a trained worker. A Project Labor Agreement is the best way to accomplish this.

Paul Metz, Professor of Geological Engineering at the University of Alaska Fairbanks, told the Council that private sector mineral exploration, the state of Alaska Division of Geological and Geophysical Surveys and the U.S. Geological Survey have identified 148 major mineral occurrences throughout the state.

About 10 percent of these, or 15 mineral occurrences, are located near the corridor that will be used by a natural gas pipeline through Interior Alaska. The gross value of these minerals are estimated, at a 99 percent probability (conservative case) at $45 billion, and $157 billion at a 50 percent probability.

In comparison, using the same valuating methodology, the gold resource at the Fort Knox Mine near Fairbanks has a value of about $2 billion. It now employs 250 people. The economic and employment impact of developing these mineral resources could exceed that of Prudhoe Bay. These new mines could employ as many as 20,000 people.

The largest single cost of mining is energy. An example of what inexpensive energy has done to help create a mining industry can be seen in South Africa, where hydroelectric power is available. The economic impact has been immense.

Howard Mermelstein, tribal administrator, agrees the pipeline should come by the southern route, but that it is important that tribal communities along the route be protected or otherwise compensated for impacts. While there will be a tremendous positive economic boost, including new taxes and government revenues, the tribal organizations are left to deal with the negative impacts. It is only reasonable that the tribes also realize some benefits. There needs to be tribal government representation in the planning for the project.

Chief Patrick Saylor, Healy Lake, told the Council that tribal organizations in his region are now wrestling with impacts of sports hunting and tourism. They support Stevens Village position that tribes should receive benefits.

Randy Mayo, of Stevens Village, told the Council that (pipeline construction) could heavily impact tribal governments. Years ago Stevens Village was one of six villages which filed a lawsuit that held up the oil pipeline over the issue of unsettled Native land claims.

In the 1930s the community had unsuccessfully petitioned the Secretary of the Interior to create a tribal trust land reserve in the area. In the eventual passage of the Alaska Native Claims Settlement Act (ANCSA) and the Alaska National Interest Lands and Conservation Act (ANILCA), the tribal interests were sidelined. Tribes lost 80 percent of their tribal land base. In relation to the lands given up, ANCSA was very inequitable. If a natural gas pipeline comes through the existing corridor, the tribes need a seat at the table.

Dean Owen, Director of the Fairbanks Industrial Development Corp., said he favored the "southern" (Alaska Highway) route because it would have the least impact on new land and would create more jobs. It is important, however, that Fairbanks have access to gas delivered along a southern route, and that it be priced favorably. He also urged that the state pipeline coordinator's office be located in Fairbanks because of the proximity to the gas pipeline. It would save money. Also, the agencies that are part of the Joint Pipeline Office, such as the departments of Natural Resources and Environmental Conservation, all have offices in Fairbanks.

He said that it is important that the state permitting agencies be able to hire adequate people to be able to keep up with the producers' permit schedules.

Russell Forest, a Fairbanks resident, said he is encouraged by the "proactive" role the Council is taking in working with communities, including the environmental community. The result will be to make this a project the whole state can get behind. Natural gas is a fuel for fuel cells, and its use is being demonstrated at the Anchorage post office. Availability of gas will allow on-site power generation to really take off, in applications at schools and hospitals. With all the jobs the gas pipeline will produce, it may take the heat off ANWR.

Paul Woodman, director of the Interior Weatherization, urged the Council to consider imposing a tax on pipeline gas throughput that would fund an endowment for residential weatherization and energy conservation. It would be a fine example to set for other states. Conservation is one of the fuels of the future.

Keith Hand, of Fairbanks Natural Gas Co., said his company is the certified natural gas utility in Fairbanks and has been in business since 1998. The company trucks liquefied natural gas from Anchorage, and now serves 200 customers through 30 miles of distribution lines. Another 15 miles of lines will be laid this summer, adding 150 customers. Fairbanks Natural Gas estimates that 10,000 residential customers in the Interior could be served with gas. The annual requirement would be about three to four billion cubic feet for residential heating, not electrical generation. This is one day of throughput for the pipeline. There are several points to be made: one recurring theme is the need for a tap on the pipeline to allow access to gas, not only at Fairbanks but at Delta and Tok. Where it is economically feasible, a tap should be allowed.

Second, prices for gas should be based on the netback using a tariff-based methodology. The state should also take its royalty gas in-kind. Third, there will be a need for infrastructure. Only a fraction of Fairbanks is piped for gas. Other communities are not ready. There's also discussion of gas service to communities along the Yukon River, by LNG distributed by barge.

Ryan Colgan, of Fairbanks, said a major North Slope gas project has been discussed for decades, with no success. Today the price of gas in Chicago is $5 per thousand cubic feet and $12 in California. There is some question as to whether these prices can be sustained. But why are Phillips and Chevron talking about importing LNG into California and BP expressing interest in building a west coast LNG terminal? At the same time, Tokyo Gas Co. was in Alaska recently expressing interest in Alaska gas. What is the State's policy?

Roger Burggraf expressed support for an Alaska Highway route, indicating it was more environmentally sound and assured more jobs for Fairbanks and new sources of energy. It also provided the possibility of a spur line to Valdez or Anchorage. The highway route would also promote more in-state industry. He couldn't see the northern route as being feasible.

Bernadette Pagel, a Fairbanks resident, expressed support for the gas pipeline. Her son is studying computer science and pipe welding at the university. She also urged the Council to consider a pipeline right-of-way with enough room for a railroad track. She also noted Senate Bill 158, pending in the Legislature, which would study state ownership of the pipeline. This is a good idea, but she would like to see the concept extended to the Permanent Fund owning part of the pipeline rather than having most of its money in the stock market.

Ross Coen, a Fairbanks resident, told the Council that skepticism can be a virtue. He had three questions for the Council: first, how the governor can decide the "highway" route is best without having the data or information to support the decision; second, why the Gas Policy Council and the Administration are relying on advice from Cambridge Energy Research Associates, the same group which said the BP-ARCO merger was good for Alaska; third, are producers willing to make gas available for use within the state? If not, Alaskans must have the spine to jerk back the leases or impose a gas reserves tax.

Steve Haagenson, of Golden Valley Electric Assoc., said Fairbanks enjoys some of the lowest rates for electricity in the state with a diversification of fuel sources, including coal and fuel oil, and access to hydro and gas-fired generation through the Anchorage-Fairbanks intertie. There was some thought given to providing power along the oil pipeline but there was little infrastructure, so oil is used to generate power for TAPS. He supports Ken Thompson's proposals for a hub for gas offtake and urged the Council to pursue the ideas Thompson has put forward. He also endorsed the State taking its royalty gas in-kind and developing a statewide energy plan.

Allen Todd, of Doyon Ltd., told the Council that the corporation he represents has 14,000 shareholders. He endorsed building the pipeline along the highway, as this route would benefit the Fairbanks area economically. Two of Doyon's business enterprises, Doyon Drilling and the Doyon-Universal joint venture, do significant work for the petroleum industry, and half of Doyon's profits are distributed to shareholders. He noted that new revenues from natural gas could be part of a long-range fiscal plan for the state, and that availability of natural gas in the Interior could energize economic development.

Tim Sharp, of Laborers Local 942, said that his union has 1,000 trained workers ready for oil-related work or related construction. The unions have also taken the lead in working with tribal groups on training. He appreciates that the oil companies must examine all possible routes, but at the end of the day the decision must be for the highway route. He noted that the governor did get plenty of input before making his decision to support a highway route. There were lots of letters and phone calls encouraging the governor to make that choice.

Mark Zoetar, of Fairbanks and a member of the Operating Engineers, has just completed a job at Clear and spent two winters on BP's Northstar project. The performance of Houston Contracting and other contractors on the Northstar pipeline is an outstanding example of trained Alaskans working successfully together to complete a project in a harsh environment. The operation was so clean "we could have eaten off the ice." When the gas pipeline is constructed some people will have to be imported to fill jobs and it is important to insure that proper training is done to insure a qualified workforce.

Jerry Isaac, of Tanacross, told the Council that his community in the eastern Interior is very excited and supportive of a gas pipeline along the highway. The community has high rates of social and economic problems, and he hopes to maximize the benefits of partnerships in working on the project.

There are also concerns. The pipeline route could be as close as a mile from the community. "Construction will definitely affect my village." Cooperation is important to insure the community benefits from the project.

Faye Ethridge, of Salcha, said that as a carpenter and mother she welcomes the gas pipeline. "My brothers and I look forward to working on it, and as a mother I want to see my grandchildren living near where I live." She urged the Council to recommend "hubs" for taking gas off the pipeline for regional development projects, and for the Council to press for more vocational training so that young people now 12 to 16 years old will have the skills to work on projects that can result as a result of the hub. She also hoped natural gas can ease high energy costs in Interior Alaska. "It's disheartening that people in Anchorage pay less for gasoline than it costs me to fill up my truck right outside the Williams refinery at North Pole."

Frank Chapados, a Fairbanks businessman, related his experience in the early 1970s forming a partnership with other businessmen to do pipeline support work, as an example of how local firms can take advantage of economic opportunities when they are presented. "Fairbanks at that time was a small town, but we managed to put it together. We performed a real service. At one time we had over 1,000 people working for us. If you give Alaskans the opportunity to perform, they will perform."

He said the State should consider investing in the pipeline. "We should do something, and not just let the pipeline go by and lose the opportunity."

Donna Robertson, of Fairbanks, told the Council she has been in business in the community for 30 years and feels that we won't be able to keep our brightest children in the state unless there are meaningful jobs. We need to train as many people as possible, and to employ as many as possible, as opportunities develop from a gas pipeline.

Wendy Lee, a Fairbanks resident, told the Council she has been a Fairbanks resident since September. She urged the Council to seek training for as many people as possible. "Don't give the jobs away."

Fairbanks resident Harry Pugh told the Council that he supports the gas pipeline coming through the Interior. He said he has worked on the slope and noticed that while there were few Native workers in the early years, Native participation in the workforce has picked up. He urged the Council to support hiring of Alaska Natives for a gas pipeline.

Alaska Highway Natural Gas Policy Council

AGENDA

May 17, 2001, 6:00 p.m. to 9:00 p.m.
Kenai Merit Inn

I. Meeting call to order/Welcoming remarks

II. Presentation from DNR Commissioner Pat Pourchot

III. Presentation from Cook Inlet Pipeline Terminus Group

IV. Public Testimony

Earlier in the day, the Council toured the Phillips LNG Plant, the Agrium Fertilizer Plant and the BP GTL Test Facility.

Alaska Highway Natural Gas Policy Council

Kenai Public Meeting Summary
May 17, 2001, Kenai Merit Inn

Co-chair Jim Sampson opened the hearing. State Resources Commissioner Pat Pourchot gave the Administration's presentation on the natural gas pipeline, potential employment, the future demand for Alaska gas and possible in-state uses for energy or feedstock for industrial development. Curtis Thayer, representing the producers' group working on the gas project, presented an overview of the companies' study project, including information on contracts recently awarded.

Mike Navarre, speaking on behalf of the Cook Inlet Pipeline Terminus Group, made a presentation to the Council. The group was founded 18 months ago with two primary goals: ensuring that as gas commercialization efforts proceed for North Slope gas, the Cook Inlet infrastructure is not forgotten; and that use of state royalty gas be managed in a way that benefit regions of the state with major population centers.

The Cook Inlet Terminus Group has met with many communities in the region and has a broad base of support for the concept of a pipeline coming south from Fairbanks to Southcentral Alaska.

Cook Inlet has existing gas facilities, a trained workforce and access to marine transportation facilities for moving products to other Alaska communities. Gas reserves in the Cook Inlet area are also declining. Fifteen years ago there was a 55 year supply; now that is down to 13 years. Exploration for new gas is just now getting underway.

Our focus is on the long-term. Seventy percent of Alaska's population lives along a route of a gas pipeline to Cook Inlet. It's the population and economic base of the state.

The economy needs room to grow, too. There is space for gas-related facilities in Nikiski, in the Matanuska-Susitna Borough and other places along the railbelt. "Lowenfels didn't tell you they'll have to knock down a mountain to build a terminal." (This is a reference to Yukon Pacific Corp. Jeff Lowenfels' presentation to an earlier Council meeting, on behalf of his company's work on a gas pipeline route to Valdez with a terminal at Anderson Point.)

A Cook Inlet route also protects jobs. The Agrium fertilizer plant is the single largest tax-paying facility on the peninsula and the largest private employer. The inlet itself is also wide and safe for marine navigation. At its narrowest point it is 12 miles wide. One thousand shiploads of liquefied natural gas have been safely shipped from the Phillips/Marathon LNG plant at Nikiski.

It appears now that our first opportunity to commercialize North Slope gas will be to ship it to the lower 48 states. But this could change fast.

There might be other gas supplies made available to the lower 48. So, we want to ensure that we're ready for any changes in market conditions. Market diversity is important to Alaska. Shipping LNG from southern Alaska gives us access to the U.S. west coast as well as overseas markets. Cook Inlet has 30-plus years of experience shipping LNG, space for industrial expansion and the potential for diversification of markets. The Cook Inlet Pipeline Terminus Group will not stand in the way of any route. All we want is to ensure that Cook Inlet is considered. If we just send our gas down the highway, we're just exporting our resources like a third world country. We would like to see a spur line to Southcentral Alaska, if not the main pipeline, considered.

Mayor John Williams of the City of Kenai welcomed the Council to the community, noting that the Alaska petroleum industry got its start on the peninsula years ago. Alaska didn't have a lot going, economically, at statehood until oil and gas activity in the inlet brought jobs and revenue to the State and local governments.

Use of natural gas has been very important. In my community, three of four major industrial facilities are based on natural gas. My message to you is that we must do everything possible to ensure as much of the gas is used in-state as possible, for space heating and to develop as many products as possible from natural gas.

There are opportunities in Kenai for gas-to-liquids plants. The BP test plant is a first stepping stone in using natural gas to make thousands of products.

I would like to see a state law that requires as much of the gas as possible to be used in-state, to process this raw resource to benefit the most number of Alaskans.

John Lau, of Enstar Natural Gas, told the Council his company supports the highway route. Enstar has a long record of service and reliability in natural gas distribution, he said.

Dan Grove, speaking on behalf of the Alaska Support Industry Alliance, told the Council that he has seen the benefits the industry has provided to Alaska. The time is right to bring North Slope gas to market, but we need to act quickly. Natural gas from the North Slope will bring many benefits, jobs and opportunities, and affordable energy.

The highway route offers an opportunity to avoid construction through undeveloped areas. Any pipeline, however, should allow opportunities for a spur line to Kenai.

Jack Brown, representing himself as a father as well as a former assembly member, told the Council that even with economic development in the Kenai areas there are still families that are "hurting" in the area. Sixty percent of the children attending elementary school in the Nikiski area qualify for the federal school lunch program. "We really need to develop a stronger economy for Alaska. I strongly support a spur line to Southcentral to stimulate the economy."

Harry Crawford, a state legislator, represents 16,000 constituents in Anchorage. He told the Council he is an ironworker. He came up the Alaska Highway when he was 22 to work on the trans-Alaska oil pipeline. "We were going to build the gasline right after the oil line, but we're still waiting. Anything I can do as a legislator to get the show on the road, I'm willing to do. Let us know."

Robert Peterkin told the Council he is a third generation Alaskan. He is a supporter of the pipeline and likes the highway route. "My way is the highway" is a good motto, and he hopes we can see a spur line built to Kenai.

Dan Chay, a Kenai resident, told the Council he hasn't heard much discussion of Alaska gas in context of global oil production. He cited some geologists' opinions that global oil production will peak in the next five to 10 years, which will cause the value of Alaska's petroleum (oil and gas) to go up. Many people have observed that there are 13 years of gas reserves left in the inlet. With our inlet gas production having peaked and in decline, it should affect our choice of how to direct the transportation of our gas, to Canada or here.

Chay cited known reserves of major inlet fields and noted that 80 percent of the reserves of the large fields have been produced, and 50 percent of much of the remaining productive fields. This suggests that the inlet fields have passed their peak. Given this, a pipeline route through Canada is not a good idea. If our concerns are for the interests of Alaskans, not the oil companies, then we should have a pipeline that brings the gas to Alaskans.

Blake Johnson, Kenai resident, told the Council that when oil production modules were built recently at Nikiski (for the Alpine oil field, on the North Slope) there was a "job fair" to inform local people of job opportunities. At the same time there were ads in Los Angeles newspapers advertising for workers for the project.

Johnson told the Council he was appalled that 60 percent of children in the Nikiski school (cited by an earlier speaker) qualified for public assistance. "Most of these people are working. They should be paid more money," he said. Jobs should be paid Davis-Bacon wages. At 40 hours a week and $25 an hour, annual pay is about $50,000. "It takes every bit of that to live up here," he said.

Keith Huss, Kenai resident, said he has been working with oil and gas industry supply firms in Alberta, and they are now very busy drilling their own gas reserves. "If we don't step up to the plate to produce our gas we'll miss the bus. Canada will fill this supply gap (in the lower 48). I hope we can get this done."

In discussion among the Council and members of the public present, co-chair Jim Sampson observed that it was helpful for the Council to tour the LNG, Agrium and GTL plants to get an understanding of what has been happening on the peninsula.

Mike Navarre, a Council member, made the comment that compressed natural gas or other technologies may allow gas to be delivered to rural Alaska, but that deliverability will be heavily dependent on port access.

State Resources Commissioner Pat Pourchot remarked that the gas pipeline being planned for the lower 48 would deliver up to 4 billion cubic feet a day through a large diameter pipeline. All uses in Southcentral Alaska total about 200 million cubic feet a day. The amount of gas moving through the large-diameter pipeline is 20 times the amount consumed for all uses in Southcentral. To make a pipeline economic, large volumes of gas will be needed to lower unit costs.

Jim Sampson said he appreciated comments regarding opportunities for jobs. "We want to ensure that our children have opportunities to work here. We're also interested in good-paying jobs, not minimum-wage jobs."

Carr Marrs, a Council member, said part of the Council's task in reporting to the governor will be to note the sustained need for gas in Alaska to help sustain the state's employment base, not just sending the resource to the lower 48 states. The volumes of gas being discussed can produce opportunities for additional employment, including many high-paying jobs. "There are a lot of things we can do."

Bob Penney, a Council member, observed that 25 years ago most Alaskans favored a pipeline through Fairbanks to tidewater. If we want to take our royalty in-kind, is there any possibility of using the Alaska Railroad right-of-way?

Carl Marrs said that the railroad offered one right-of-way and that utility corridors were also available. "All of us agree that at present rates of Cook Inlet gas production and consumption, we will probably see problems beginning in 2006-07 without finding additional resources. Estimates are another 1.3 trillion cubic feet could be discovered. It will be more costly, particularly if it is offshore. Drilling offshore in some areas may be essentially impossible, due to environmental constraints."

Ed Rasmuson, a Council member, recalled that his father, Elmer Rasmuson, observed 40 years ago that natural gas has more potential to develop the state than oil. He said a gas pipeline along the highway route, with a possible spur to Southcentral Alaska, should be a must. There could also be possibilities for a small spur line from the highway pipeline to Haines, he said. Rasmuson also said the question of whether Alaska should be a part-owner of a gas pipeline is important.

Jack Roderick, a Council member, said he thinks there will be more gas found in Cook Inlet. He added that agreements to keep as much of the gas in-state as possible should be an important part of negotiations with producers.

Mike Navarre pointed out that if gas is taken in-kind and used to encourage economic activity, there are also costs to the State that result. "We're taking gas that would generate revenues to the treasury if the gas is sold in-value to producers and using it to create additional demands on public services. We need to develop alternative revenues to the State, through taxes or contributions from the Permanent Fund."

Mayor John Williams, of Kenai, said a few months ago he attended a meeting with other mayors of the municipal Port Authority, during which information had been presented on the capacity of gas transmission systems in Canada. "If the Canadians beat us to the use of that capacity, does it mean we have to build a pipeline all the way through," to the U.S. markets?

Curtis Thayer, of the producers' group, explained that his group is studying the "B to C" pipeline options, the capacity of existing Alberta to U.S. transmission.

Council member Carl Marrs asked about the maximum existing capacity in Alberta to U.S. pipeline systems. *(Note: Information on this subject was included in a presentation given by Cambridge Energy Research Associations at the Anchorage Public Hearing on May 24.)*

Council member Bob Penney observed that if the one-eighth state royalty gas is taken in-kind and used in-state for other purposes, it would reduce the amount of gas throughput available to finance the main pipeline. This would increase costs of transporting the other 7/8 of the gas.

Scott Heyworth, an Anchorage resident, told the Council that 4 billion cubic feet a day of gas moved for 365 days per year, would move about 1.46 trillion cubic feet per year, moving all of the North Slope's current estimated reserves of 35 trillion cubic feet in about 24 years. Also, the existing treaty with Canada, agreed on when the Alaska Natural Gas Transmission System was negotiated, specifies a maximum throughput rate of 2.5 billion cubic feet per day. "How can we get around that?"

State Resource Commissioner Pat Pourchot responded that the State has asked for advice on the treaty from its experts in Washington, D.C. He said the amount of gas to be moved isn't actually specified in the treaty, and that 2.5 billion cubic feet/day is used only as a guideline. There isn't anything in the treaty that precludes a larger amount. Pourchot also noted that the original Prudhoe Bay oil reserves had indicated, in the 1970s, that the trans-Alaska oil pipeline might be a "20-year project. We've obviously moved many years beyond that," in terms of additional oil reserves and the life of the pipeline. The same thing is likely to happen with natural gas.

Heyworth replied that present revenue Commissioner Wil Condon had written, in 1982 (when Condon was a state attorney) that the U.S.-Canada treaty is very limiting.

Dan Chay observed that if 4 billion cubic feet per day were shipped in a pipeline along the highway and that if Southcentral Alaska required only 200 million cubic feet of gas per day, if the perspective of the Council is to look at this issue over several generations and assuming that gas will be worth a lot more in the future, then a pipeline through Alaska even at lower rates of throughput might be a service to Alaskans.

Council member Bob Penney made the remark that, "we don't own all of the gas. We only have rights to our one-eighth royalty share."

Chay responded that the State still has some negotiating room in powers it has to set the rate at which gas production takes place.

Carl Marrs observed that whether gas is worth more or less in the future is also a factor of technological change, which is unpredictable. There is also a lot of gas in other places, like Indonesia. In a broader context Alaska is a small piece of the worldwide gas business. Some geologists also say the western U.S. sedimentary basins are on the verge of decline. While LNG is expensive it may be more competitive in the future.

Tom Maloney, an Anchorage resident, told the Council that the company he worked for, Veco Alaska, Inc., started in Kenai in 1968. He himself came up to work on TAPS construction and as soon as the job was over, he went back to the lower 48. What's different between the gas project and TAPS is that in the four major contract packages let so far, all four have heavy participation by Alaskans companies. Veco is in two of the packages; Natchiq is in the gas treatment plant and "B to C" package. It's important that Alaskan companies are involved in this front-end engineering because in a major project like this about 70 percent of expenditures are in engineering and procurement. This year Veco will have 25 engineering intern students, 80 percent of them Alaska Native. Without projects like this, we can't keep high-tech engineering jobs like this in the state. We need to have good jobs to bring back Alaska kids who go outside for their education.

Joe Arness, a Kenai resident and a third generation Alaskan, recalled the bumper stickers after TAPS construction, "God Give Us Another Boom, We Won't Mess It Up This Time." Arness told the Council that a gas project won't be like the TAPS project. But his concern is that the governor's favored proposal of a gasline to the U.S. heartland (via the Alaska Highway) will be such a source of cheap energy for continental U.S. that it could make it politically impossible to peel off gas supply to benefit Alaskans. "I suggest a 48-inch pipeline to Southcentral Alaska, and then a spur line down through Canada."

Alaska Highway Natural Gas Policy Council

AGENDA

May 24, 2001, 12:30 p.m. to 9:00 p.m.
Egan Convention Center, Anchorage

Subcommittee Work Sessions

I. Optional subcommittee meetings *(schedule to be determined by each individual committee chair)*

Council Meeting

I. Call to order

II. Council business meeting

III. Presentation from Cuba Wadlington, President, Williams Pipelines

IV. Presentation from Ed Small, Cambridge Energy Research Associates

Dinner break

Public Hearing

I. Opening remarks

II. Opening remarks from Governor Tony Knowles

III. Presentation from DNR Commissioner Pat Pourchot

IV. Presentation from Ken Thompson on "the Hub" concept

V. Public testimony

Alaska Highway Natural Gas Policy Council

Anchorage Meeting and Public Hearing Summary
May 24, 2001, Egan Convention Center

Cuba Wadlington, Jr., Senior Vice President of the Williams Companies and president of Williams Pipelines, a major U.S. gas pipeline company, gave a presentation on his company's interest in the Alaska gas projects. Williams markets fuel in Alaska and operates a refinery in Fairbanks. Wadlington said Williams is interested in being involved in an Alaska gas project and has initiated a study on possible petrochemical manufacturing in Alaska using gas as a feedstock.

The Council also heard a presentation on North American gas supply and demand by Ed Small of Cambridge Energy Research Associates (CERA).

Small told the Council that CERA does not subscribe to the "30 tcf (trillion cubic feet)" world. We do not see any scenario, not even to 2015, where U.S. domestic demand is likely to reach 30 tcf per year. *(Note: Small is referring to some forecasts calling for U.S. domestic demand to grow from 21 tcf/year (present) to 30 tcf/year by 2010. CERA thinks this is unrealistic.)*

Domestic markets have gone through two stages in recent years, the first being where markets followed what CERA calls a "gas-favored" scenario, where supply and demand progressed gradually in step with each other. We have now shifted to a "realignment" scenario, where gas supply has fallen short of demand. This is a stage we are still in. This could be followed by a scenario we call "aftershock," which could see a recession and slower growth.

Western Canada was one area that faltered last year in meeting its expected growth of gas supply. We were flat last year in terms of growth. Much of this was due to the fact that most drilling was for shallow gas, prompted by low oil prices. We've now seen a tremendous increase in drilling, and we're seeing a supply response. We now expect 16 bcf per day production from the region growing to 19 bcf per day by 2010.

The Scotian Shelf offshore project off Nova Scotia in eastern Canada is an area where there will be increased supply. This project is now producing 4 million cubic feet (mmcf) per day, and we expect this to grow to 3 bcf/day by 2015.

Liquefied natural gas (LNG) is another source of new gas supply to domestic U.S. markets. There are now 4 LNG regasification facilities in the U.S., two of them operating and a third which is just restarting operations. We expect all four of these to be operating and to grow to 3 bcf per day by 2010. They will actually be capable of 4 bcf/day but for maintenance and other reasons actual supply will most likely average 3 bcf/day.

There will also be other new supplies possible from western Canada and from the Rocky Mountains.

Even with these new supply sources, there is an opportunity, a "window" for Arctic gas, which would appear at the earliest in early 2008. This could grow to 4 to 4.5 bcf/day by 2015.

However in the last 6 months, 6 to 7 new LNG projects have been announced to serve the U.S. market. Two of these are in Baja California, which would serve California. We believe LNG projects are now feasible at $3 per mcf, so this sets a benchmark for Arctic gas. Not all of these LNG projects will be built, of course, but how many are built will be influenced by how quickly decisions are made on Arctic gas (i.e. earlier decisions will cause developers of some LNG projects not to proceed).

Under different scenarios we foresee, if there is a recession and slower U.S. market growth, it is unlikely that there will be both full-blown Alaska and Mackenzie Delta gas projects. We would expect to see the Mackenzie Delta project come first, followed shortly by an Alaskan project, probably in 2012.

The risks include gas prices. Sustained prices in the $3 range is probably the break-even point for Arctic gas, and this is the same for new LNG projects. There have been tremendous technological gains, and cost reductions, in LNG in recent years. There are other stranded gas LNG projects in the world that will be done before an Alaska LNG project, however. In this same price range, Arctic gas projects would be feasible, in the $2.50 to $3/mcf range.

Another new challenge, however, will come from clean coal projects. These can now be done in the low $3/mcf range. There are now 14,000 megawatts of new clean coal projects being proposed.

Another factor influencing the market is demand reduction due to high prices. High gas prices last year resulted in some 5.5 bcf/day of demand switching to other fuel sources. About half of this has come back as prices have softened, but we see 3 bcf/day having switched to fuel oil and remaining with that fuel.

There are political questions that affect the Alaska gas project. Two thirds of the pipeline will be through Canada. Recent legislation passed by the Alaska State Legislature (a bill prohibiting a lease of state lands for a "northern" pipeline right-of-way) has had negative effects in Canada. Previously the Canadian federal government had (and still does have, officially) a policy of neutrality as to a "northern" or "southern" route. The government would allow economics to dictate the route.

However, if the State of Alaska says "no" to one route option, this injects a political element. This sets the stage for negotiations "as to who will pay" if a southern route is seen to disadvantage Canadian gas development.

It must be recalled that the Canadian federal government agreed to the original ANGTS treaty on the condition that there be a linkage to Canadian gas development, in the form of a commitment to a Dempster Highway "lateral" pipeline to the Mackenzie Delta. The Dempster lateral is not now a viable option because previously unresolved land claims had blocked the more economically-attractive Mackenzie Valley route. Now those claims are resolved, and a pipeline from the delta would be built along the Mackenzie Valley. However, there is now a possibility that the Canadian government will seek a "linkage" between the Alaska North Slope and Mackenzie Delta projects, as it did in the 1970s. In any event, "we don't see a commitment feasible (by the government) until next year."

Another consequence of last year's high gas prices is that power plants are now shifting from short-term to long-term supply contracts for gas. This is seen as a positive development for Arctic gas (because long-term contracts will help those projects).

Another important question to be dealt with is disposition of natural gas liquids (NGLs). Both North Slope and Mackenzie Delta gas contain NGLs which will have to be removed and sold before the gas is ultimately sold to natural gas utilities. NGLs are usually considered the ethane, propane and butane portions of the gas stream (methane, the primary component, is what is mainly used by utilities). One option is for a plant in Alaska to strip out the NGLs, with only methane transported to the lower 48. The NGLs will then have to be marketed in Alaska. A second option is to build an NGL extraction plant in Alberta, where there is an existing petrochemical industry that could buy NGLs. A third option is to move the NGLs all the way to the lower 48, with a liquid extraction plant built there. New, high-pressure (dense phase) pipelines are now capable of carrying the NGLs along with the methane.

If NGLs are shipped along with methane in the pipeline, the energy content and value of the throughput is increased. If NGLs are extracted in Alaska, so that only methane is shipped, the energy content and value of the throughput will be reduced. "This would have the effect of increasing the hurdle rate (minimum rate of return for investment) of the project, and I'm not sure we want that," Small said.

The new Alliance Pipeline to Chicago is a high-pressure pipeline carrying NGLs from western Canada to Chicago, but the liquids business in Chicago has not been profitable, Small said. The demand for NGLs in the Chicago area has been less than estimated and the plant has been losing money. Were it not for the high prices for the methane (the natural gas) the Alliance project would be losing money, he said.

In summary, CERA sees natural gas prices of $3.50 to $3.75 to 2005. Beyond that it is more difficult to predict. Arctic gas will not be entering the market until 2008, and even at the rates expected, of 2 to 2.5 bcf/day, it will have somewhat of a depressing effect on prices when it enters the market.

Small said he has seen estimates of $6 billion to $8 billion needed to build the pipeline from Alaska to Alberta. Gas will then need to be moved another 1,400 miles to U.S. west coast markets or 2,400 miles to the Chicago area. CERA estimates there is about 2 bcf/day capacity available, with expansions, in the existing Alberta-U.S. infrastructure. The question will be who gets it, the Canadian or the North Slope producers?

Co-chair Frank Brown asked for more information about sentiment in Canada.

Small said the Canadian government's concerns will be on commercialization of gas in the Mackenzie Delta and Mackenzie Valley. It is believed that the delta has 9 tcf of proven gas reserves and growth potential to 45 tcf in the region. This is enough gas to justify a stand-alone pipeline. Under certain circumstances the Alaska pipeline could preclude development of a pipeline from the Mackenzie Delta, possibly until 2015. This will be the Canadian government's major concern, which has been heightened by the legislation passed by the Alaska Legislature.

Council member Brian Davies asked Small to explain again the possible sequencing of Alaska and Canadian gas development.

Small said the most likely timing for Alaska gas to enter the market is 2008, followed by the Mackenzie Delta gas in 2009. Alaska would enter the market at 2 bcf/day, increasing in stages to 2.5 and 3 bcf daily. Mackenzie Delta gas would likely begin at 1 bcf/day increasing to 1.5 bcf/day.

However, there is a scenario in which Mackenzie delta gas could come first. That is if a recession hits the U.S. and demand growth slackens. In that case it will be difficult to raise the large amounts of investment needed for the larger Alaska project. Thus, Mackenzie gas could enter the market first in 2008 or 2009 at about 1 to 1.5 bcf daily, followed by Alaska gas in two to three years, or 2011.

There is also a scenario, which seems unlikely at this point, which would see a larger response than is now estimated from other gas supply sources to the U.S. market. Under this scenario there could be no Arctic gas flowing to market until about 2011. Alaska gas would enter the market at that time, followed by Mackenzie gas a year or two later.

Several Council members asked for clarification of estimates of tariffs on one of the charts in the CERA presentation.

Small explained that the estimate for an Alaska Highway gas pipeline under the ANGTS published estimates were a range of $1.80 to $2.20 per mcf to the U.S. market. Of this, about 85 cents is for the Alberta to U.S. portion. "This is why a gas price of $2.50 per mcf (in the lower 48) barely cuts it, while $3 will make it viable."

The public hearing portion of the meeting began. Gov. Knowles and Anchorage Mayor George Wuerch gave some opening remarks.

State Department of Natural Resources Commissioner Pat Pourchot gave the Administration's presentation on the natural gas pipeline, potential employment, the future demand for Alaska gas and possible in-state uses for energy or feedstock for industrial development.

The Council heard a presentation from Ken Thompson, a Council member, on his concept of a gas trading "hub" in Alaska and the importance of having agreements in place for access to gas in Alaska before a gas pipeline begins construction. Curtis Thayer, representing the producers' group working on the gas project, presented an overview of the companies' study project, including information on contracts recently awarded.

Larry Crawford, president of Anchorage Economic Development Corp., introduced AEDC staff economist Jeff Pokorny to present a summary of the Cook Inlet gas supply situation. AEDC undertook the study because there were a lot of misunderstandings about regional gas supplies. AEDC worked closely with Chugach Electric Assoc. and Enstar Natural Gas. "We believe it is the most accurate assessment to date of the situation."

Pokorny told the Council that gas production began in Cook Inlet in 1959 and that by 1975 about 8.5 tcf had been found. About 215 billion cubic feet per year is used in the region, approximately two-thirds for industrial uses and one third for use by utilities, in electrical generation and residential and commercial space heating.

Reserve-to-production ratios in the lower 48 are fairly consistent with about 8 to 10 years of supply because the reserve base has been replenished with supply additions. In Cook Inlet the reserve base has been declining because there have been no significant reserve additions in recent years.

The most commonly-accepted estimates of conventional gas yet to be discovered in the inlet range between 1 and 2 tcf, although there are some estimates of 3 tcf. There are also possibilities for conventional gas supply additions in the Matanuska-Susitna area (north of Anchorage) and from gas from shallow coal beds. Estimates are that coal-bed methane resources could be about 8 tcf. U.S. government geologists have estimated a total resource of 250 tcf in coals in the Cook Inlet basin (much of this is deep, however, and unlikely to be commercially produced). The study also cited possibilities that gas could be imported as LNG (the LNG plant in Kenai could be converted from liquefaction to regasification) for a price in the range of $2.50 to $3 per mcf, which is about the price LNG from Asia is being considered for projects discussed for western Mexico.

The study cited options for extending current Cook Inlet region gas supplies. If gas sales to the Nikiski LNG and fertilizer plants were terminated, gas supplies would be extended 6 years. If supplies to only the LNG plant were terminated, supplies would be extended 3 years. The study also noted that as gas prices in Cook Inlet increase, both the LNG and the fertilizer plants could be at risk.

Other findings were that the LNG plant at Nikiski could clearly be at risk by 2009 because the export license is up for renewal at that time (the federal government will not renew the license unless gas is surplus to local needs).

In summary, gas supply in the Cook Inlet region is still better off than in the lower 48, in that there is still a 13-year supply in Cook Inlet, while the lower 48 has an 8-year supply.

In response to questions from the Council, Pokorny related that problems in daily deliverability of gas (at peak times, i.e. during cold weather) could begin as early as 2004. Discovery of 1 additional tcf of gas would extend the peak-time deliverability to 2007. Discovery of 2 tcf of gas would extend it a little further.

Carl Marrs asked at what price coal-bed methane might be economic.

Pokorny answered that there was no clear answer to this. It could be in the range of $3 to $4 per mcf.

Council member Brian Davies observed that coal-bed methane is economic in the lower 48 at today's prices. Coal-bed methane technologies are very specific to the sites where they are applied, and in Alaska the technologies for our particular geologic environment have yet to be developed. Current prices in Cook Inlet do not support local coal-bed methane development but as prices go up it is certainly a possibility.

Council member Jack Roderick asked if AEDC was aware of any studies underway for mine-mouth coal power plants in the region.

Pokorny answered he was unaware of any studies. *(Note: Owners of the Beluga coal fields near Anchorage are now considering possibilities of mine-mouth power generation, as well as gasification, from their resource.)*

Council member Ken Thompson observed that studies several years ago by ARCO Alaska Inc. indicated that, in the long term, gas from the North Slope could be delivered to the Cook Inlet area for less than new conventional supplies could be developed within the region.

Gene Bjornstat, general manager of Chugach Electric Assoc., told the Council that Chugach generates 83 percent of its electricity from natural gas and 17 percent from hydro. There is also coal-fired generating capacity in plants at Healy, supplying Golden Valley Electric Assoc. Chugach has been generating electricity at its plant in the Beluga gas field since 1965. Gas from Beluga was purchased for 15 cents per mcf when the plant first went into operation.

Bjornstat told the Council that Chugach appreciates its consideration of the regional supply problem and believes that decisions made sooner are better than later on this question. Ken Thompson's suggestions of a gas hub and gas takeoff contractual arrangements are very appealing. Timely recommendations and decisions on those will help Chugach in its planning.

Steve Cleary, speaking on behalf of the Alaska Public Interest Research Group, said his members' concerns were those of consumers and utilities in the region. "In the next decade our members will need a reliable source of gas, and we think it must be North Slope gas." Options like burning coal (for local fuel) are not very appealing, and as for importing LNG, if we are concerned about dependence on foreign markets for sales of oil we should be equally concerned about dependence on foreign sources of gas supply.

Alaska Public Interest Research Group would like to see the discussion of supply and use broadened. Cleary said he is intrigued by the hub concept and the use of royalty gas in-kind. He said the Alaska Public Interest Research Group has four criteria to recommend to the Council for consideration: one, that gas be used to benefit Alaskans first; two, that the State profit from gas production (through royalties and taxes); three, that State controls are in place for local access to gas; four, that there is an option for deliverability of gas to tidewater.

Cleary asked that the Council consider a question, that if there is only a pipeline to the lower 48 and that if markets there dropped, the State would lose money (from royalty and tax) but the producers (if they are also owners of the pipeline) would continue to make money through their equity ownership of the pipeline.

Tony Izzo, president and CEO of Enstar Natural Gas, told the Council that he had not planned to speak but felt compelled after hearing the presentations. Enstar serves approximately 50 percent of the state's population and has done so for 40-plus years. "We have one of the best gas utilities in the country, with new high-tech systems, 400 miles of pipelines and 2,400 miles of distribution lines. We are ready to be of service."

We believe Ken Thompson is right on the mark. We endorse the idea of a hub in Fairbanks. Enstar has contracts pending to meet our supply needs to 2006, and we have some contracts that will fill part of our needs to 2017. But we have long-term concerns, beyond that.

"I did some quick calculations, and at our present rate of consumption the 35 tcf of known gas reserves on the North Slope are sufficient to meet the needs of Southcentral Alaska for 175 years. If only the utility needs are considered, which is about one-third of demand, the known North Slope gas reserves are sufficient for 580 years." In making decisions on use of North Slope gas, "we've got to make sure we take care of ourselves."

Council member Carl Marrs asked at what cost an additional 1 to 2 tcf in Cook Inlet could be made available?

Izzo replied that there were no clear estimates, "but in my opinion the cost will be substantially higher" to acquire an additional 1 to 2 tcf of gas in Cook Inlet. Current gas prices in the region are about $2 per mcf, and the most recent contracts are in the $2.75 per mcf range. He also said Enstar is very interested in a spur pipeline to either Fairbanks or Delta. "We are very interested in securing additional long-term gas supply for Southcentral Alaska."

Scott Heyworth, speaking for his company "Our Gas, Our Future" told the Council that he is aware of 6 LNG projects Phillips is initiating in Asia, one project BP is involved in to import gas to Bolivia, and that LNG from Asia is now being considered for California, "which is the natural market for gas from Alaska." With the shift of control in the U.S. Senate, "ANWR is dead on arrival, and the support the governor has counted on for the Alaska Highway gas pipeline is in trouble. But we can do our own all-Alaska gas pipeline by ourselves" (i.e. no congressional approvals are needed).

Heyworth noted that costs of $10 billion are currently estimated to build the "A to B" pipeline segment from Alaska to Alberta, another $3 billion to build pipelines to lower 48 markets and another $2 billion to build a liquid extraction plant somewhere. This totals $17 billion in 2001 dollars (i.e. an investment sufficient for a large-diamater pipeline across Alaska and an LNG plant in southern Alaska). What makes more sense for Alaska? A pipeline to Chicago, or to Valdez? I know Alaskans don't support an Alaska Highway route. An all-Alaska route with an LNG project is in the best interest of Alaska.

Council member Ken Thompson observed that commodity markets always cycle up and down, and asked Heyworth that if the Asia markets are able to absorb 14 millions tons of LNG yearly from Alaska (the volume produced by a large-scale LNG project), what's wrong with starting smaller at a rate the Asia market will absorb, such as 1 to 2 million tons per year, and then ramping up?

Heyworth replied that he favored the "Y" concept (a pipeline branching off from a large-diameter main line) but that the pipeline should be built to Southcentral Alaska first, and then to the lower 48 when the inevitable litigation over the Alaska Natural Gas Transmission System laws and treaty are finally resolved.

Mike Macy, responding to Ken Thompson's question, observed that it's also a question of economies of scale. A large LNG project will be able to get into the Asia market at a more competitive price. Macy complained that Governor Knowles had made his decision to favor an Alaska Highway route for a gas pipeline without consideration of all alternatives. The governor has never listened to a presentation on a liquefied natural gas export project being proposed by Yukon Pacific Corp., for example. Macy also urged the Council not be used as a "shield" by the governor, to help justify his decision in favor of the highway route.

Council co-chair Frank Brown observed that Jeff Lowenfels, president of Yukon Pacific Corp., made a presentation on his project at an April meeting of the Council in Anchorage.

Council members Carl Marrs and Charlie Cole told Macy they do not consider themselves, being members of the Council, as "shields" for the governor. "I'm here to learn," Marrs said, "The governor is waiting for answers from us." Cole told Macy he had listened carefully to Lowenfels presentation of the LNG option and thought it excellent. "What we do here is not in opposition" to the proposal, he said.

Council member Ken Thompson said he favors LNG from Alaska but that it might not happen on this market cycle. "But would you favor a hub, with the first project to plug into the hub being a pipeline to the lower 48? A hub doesn't say 'no' (to LNG,) it says 'yes.' From 1998 to 2000 I marketed LNG in Asia," and it is ironic that Alaska represents a large source of gas supply to Asia but the very size (and capital cost) of the project needed is a major obstacle, relative to competitive supply sources. "Fourteen million tons per year of LNG is tough to sell in a market of 60 to 70 million tons per year. But I do believe there's room for 1 to 2 million tons. I wonder if we need a paradigm shift? Maybe a smaller project is better?"

Macy replied that there are reasons why North Slope producers don't want LNG from Alaska going to Asia. It is because there are finite terms on leases and concessions the producing companies have in Australia and Indonesia. "They're putting that gas in California and Japan. Those are our markets. If we could sell 9 million tons/year to Asia and 5 million tons/year to California, we've got our large-scale LNG project."

Tom Marshall, a retired state geologist, told the Council that 30 years ago Natural Resources Commissioner Phil Holdsworth sent him to Juneau to explain to the state Legislature the implications of the natural gas found associated with crude oil in the Prudhoe Bay oil discovery, which was announced a short time earlier.

Marshall explained at the time that the best near-term use of the gas would be to maintain pressure in the reservoir to support oil production. As the years passed this pressure maintenance, along with injection of water and misciple injectant (a fluid made from natural gas liquids, used in enhanced oil recovery) has resulted in $100 billion in the value of additional oil produced. The availability of gas for enhanced oil recovery has also aided in production of oil from the Kuparuk River and other oil fields on the North Slope, and will play an important role in production of viscous (heavy) oil from the very large West Sak and Ugnu formations.

"What concerns me (about the discussions of natural gas being commercialized and moved off the slope) is that I want to see as much of the gas as possible used where people live. Seventy five percent of Alaskans live along the railbelt." Our gas is in the railbelt, "it will take a little ingenuity to figure out how coastal LNG tankers can move gas to other coastal areas."

Another concern is that we hear estimates of 35 tcf of reserves on the slope. "If we produce at 4 billion cubic feet per day, this is a 25 year supply. If we use a more realistic figure of 26 tcf (actually available for commercial sale after uses on the North Slope) and we subtract the 14 percent of this gas that is carbon dioxide (which will be removed from the gas before it is shipped) and natural gas liquids, we have a project with known reserves sufficient for 17.8 years. However, a large project like this must be able to operate for at least 30 years to justify the investment. "Therefore, whoever is building this project is depending on undiscovered resources. As a geologist, I will tell you that is pretty risky."

"It doesn't make any difference to me whether we deliver North Slope gas to Chicago or Japan, but I do want to see gas made available in Alaska. Gas can be used for so many things. In the Fraser River valley of British Columbia, local gas is used to heat greenhouses to make tomatoes for export to California. Gas is the preferred fuel for fuel cells. The options for using gas in Alaska will create many opportunities for our young people."

"The North Slope petroleum province is so much beyond anything I have seen in the south 48 states, but the concern I have is that BP, Exxon and the other producers will figure out a project that is just large enough" for an Alaska Highway route. "The North Slope could give Alaska a stable supply of gas for 100 years. Let's serve Alaska first and if gas reserves turn out to be very large, then we can send it Outside. What's wrong with creating economic incentives for using the gas in Alaska? It's okay to give Alaskans an economic advantage."

Council member Carl Marrs observed that "all of us would like to find ways to enhance the value of gas used here, but on the economic side we must assure whoever is doing the project will get a return."

Marshall replied that the governor and his advisors are well motivated to pursue an Alaska Highway route. Economics are important, and markets and prices do change. The project may not look so good at $3 per mcf (prices in the lower 48). The gas pipeline is an extremely complex problem. It won't be solved with a snap of the finger.

Jerry McCutcheon, an Anchorage resident, told the Council that there were documents held at one time by the Alaska Oil and Gas Conservation Commission related to estimates of Prudhoe Bay oil and gas in-place resource estimates that have disappeared. He encouraged the Council to try and locate these documents. McCutcheon said there could be more oil produced from Prudhoe Bay and using gas to maintain the reservoir pressure is important.

Harold Heinze, an Anchorage resident, told the Council he is a former ARCO Alaska Inc. manager and a former state Commissioner of Natural Resources. When he was at DNR he worked actively to market Alaska's gas. "I came here in 1969 and I lived through the TAPS years. I think we can avoid some of the mistakes made during TAPS. Clearly, the governor should be congratulated in forming this Council and getting an important dialogue started." On projects like this, "I would like to see us consider things like an Alaska-Yukon 'free trade zone.' There's no reason that the project changes at the border." The Alaska and Yukon people both have priorities in maximizing jobs. We should all have opportunities to work up and down the pipeline. "The President has made it clear that he considers having good relations with Canada very important." Heinze also recommended that local citizen advisory groups be formed as part of the pipeline planning effort up-front. This wasn't done during TAPS, but there were tremendous impacts on small communities. On local-hire, "we need a more creative approach. The pipeline is being built across our (state) land. There has got to be some way we can legally ensure local people" are given priority in hiring. "We should also be flexible when we discuss the need for gas. Sometimes it's smarter to move electricity than gas. We could think of the Delta-Glenallen-Fairbanks areas as the electricity belt," where it could be more economic for regional power plants, fueled by gas, to produce energy than to build gas pipelines.

Heinze also urged the Council to move these discussions along. "I've lived here for 30 years and I've seen us at this point before, and there is value in taking action." He also said he is concerned that the

Alaska Oil and Gas Conservation Commission is "behind the curve." The current Prudhoe Bay field rules do not permit commercial gas sales, and AOGCC hearings will have to be held before they are allowed. "I know that the questions will be answered, but the AOGCC needs to get on it." Heinze also endorsed the concept of a State gas pipeline office, where everything having to do with gas pipeline decisions are in one place. "It's unfortunate the Legislature didn't provide for this. We've got to find the money and get on with it."

DNR Commissioner Pourchot mentioned that at the very end of the session the Legislature did provide some money for startup of a state gas pipeline office.

Heinze recommended the Council obtain copies of a 1983 publication by the University of Alaska's Institute of Social and Economic Research titled, "The Struggle for an Alaska Gas Pipeline," as excellent background reading. "The State of Alaska needs to be looking at its own best interests, but also why things are being done the way they are. Some issues are not as obvious as they might seem. My instincts tell me that Alaska hire is a bigger issue than many people think."

Council member Jack Roderick asked Heinze his opinions on the State taking an equity position in the gas pipeline.

Heinze replied, "I hate to see the State put in hundreds of millions of dollars to get information it could get through regulatory processes. I have a dim view of this because the State does not have a management vehicle to make risk investments."

Council member Ken Thompson observed that if the State doesn't have an equity interest, it pays a tariff (to private equity owners) for transport of royalty gas that includes federal taxes. With an equity share, "we can move our own gas at lower cost" (because the state would pay no federal tax) and pass these advantages on to in-state gas users.

Heinze replied that the Department of Revenue will be doing a study of possible state equity participation. "But I wouldn't leap too quickly."

Council member Charlie Cole observed that during the TAPS tariff negotiations in 1985 the State was able to take the position that as an owner of oil reserves it favored low tariffs, which also enhanced exploration. If the State had an equity interest, its interests in low tariffs might change.

Heinze commented that there are also issues around the "trajectory" of the tariff. In the 1985 TAPS tariff proceeding the State chose to allow high tariffs in the early years in order to allow low tariffs in the later years of the pipeline. "Without that (tariff structure) our royalty oil would be worth less. We may face policy choices like that with a gas pipeline, too."

Paul Simons, an Anchorage resident and a retired chemist, urged the Council to consider the possibility that gasification plants can be built on coal fields, with many products made from the gas. This is being done now by Sasol in South Africa, and a large U.S. coal gasification plant is operating in North Dakota.

Alaska Highway Natural Gas Policy Council

AGENDA

June 14, 2001, 5:00 p.m. to 8:00 p.m.
Tok School

I. Community Reception sponsored by Doyon, Ltd.

II. Meeting call to order/Welcoming remarks

III. Presentation from DNR Commissioner Pat Pourchot

IV. Public Testimony

Alaska Highway Natural Gas Policy Council

Tok Public Hearing Summary
June 14, 2001, Tok School

Council members attending included Co-chair Frank Brown, Mike Navarre, Rosemarie Maher, Rhonda Boyles and Charlie Cole. State Natural Resources Commissioner Pat Pourchot and Deputy DOTPF Commissioner Kurt Parkan also attended.

Co-chair Brown, who presided at the meeting, suggested a more informal question-and-answer session rather than the traditional public hearing format for a meeting.

(Note: Because the meeting was informal, with people asking questions and making comments from the audience, the editors were unable to get names of people speaking.)

Brown explained the Council's purpose: to study options for maximizing benefits of the natural gas pipeline to the state and to make recommendations. The governor has also formed a gas cabinet within the Administration, headed by Commissioner Pourchot.

Pourchot gave the Administration's presentation on the gas project.

A question from the audience asked how Alaska was coordinating with Canada on the gas pipeline.

Pourchot responded that Canada's federal government has just set up its mechanism to work on the project. The Prime Minister has set up a "gas cabinet" just as Alaska has done, with seven to eight departments involved. "They are clearly up to speed, although they are, officially at least, still neutral on the route question," the Commissioner said. Canada's parliamentary system allows the government to form unified positions because the party controlling parliament forms the government. The federal government is more in control of events in the territories, such as Yukon and Northwest Territories. Once the pipeline crosses into British Columbia and Alberta the provincial governments will exercise considerable influence.

An audience member asked about the preference by some Canadians for a northern route, and asked about the status.

Pourchot answered that Canada's federal government has taken the position that it doesn't want its northern gas stranded. The government doesn't want the movement of Alaska's gas to strand Mackenzie Delta gas.

The government also shows sensitivity to the concerns of aboriginal groups. The situation on aboriginal land claims in Northwest Territories has now changed, however. Most claims there have been settled, and the interests of aboriginal groups are now aligned with development of a pipeline along the Mackenzie River Valley. However, land claims in Yukon and northwest British Columbia are not settled, and they will have to be settled before an Alaska Highway gasline is built. There are discussions on this under way now, Pourchot said, although the status of talks is unknown.

A question was raised on status of a gas pipeline to Valdez. Has it been eliminated?

Pourchot replied that a pipeline to Valdez would require use of liquefied natural gas technology and reliance on markets in Asia. "Our best information is that the Asia market does not now support a stand-alone pipeline to Valdez. However, the Alaska Highway route (to the lower 48) does not rule out a spur pipeline to an LNG plant in the future." Natural gas prices in the lower 48 are very strong, about $4 per million cubic feet (mcf) now. Although the price has slipped (it was $5/mcf) it is still higher than the $2/mcf two years ago.

A question was raised about the timeline for a gas pipeline.

Pourchot responded that the producers will make this decision, but the best information the State has is that a target date of 2007 is under discussion.

A member of the audience asked about the impacts of gas pipeline construction. Since the technology is simpler than the trans-Alaska oil pipeline, wouldn't the impact be less?

Pourchot replied that the workforce requirements for the gas pipeline would be far less than TAPS, partly because the infrastructure is available to support construction. The gas pipeline technology is newer, but the entire project is simpler. Since the pipeline will be buried in total there isn't the need for the extensive design and engineering work needed for above-ground sections as for the TAPS line, or the vertical support members. There will still be two to three construction seasons involved. There will be thousands of people employed, but considerably less than TAPS.

One member of the audience asked what benefits the project would bring for small communities. Tok has no incorporated regional government and no opportunity to use the pipeline as a tax base. To use the gas, a gas utility will have to be established. The compressor plants for the pipeline present opportunities for use of waste heat, but the location of the compressor stations is not yet known. "I support the highway route, but what is the long-term benefit?"

Co-chair Frank Brown replied that the option to form a local government lies with the community. Presence of a pipeline doesn't automatically mean a government will form. The TAPS oil pipeline was built through the Glennallen area almost 25 years ago but there is still no borough government in the area. It is true that it isn't yet known where compressor stations will be located, although it is believed that several will be in the Tanana River valley. In the old Alaska Natural Gas Transportation System proposal there were 12 compressor stations planned in Alaska. The new plan will probably involve fewer, and they will be more automated with fewer people operating them.

A question was asked about local hire, meaning hiring from the local community.

Council member Mike Navarre replied that there is a subcommittee working on this. The Departments of Labor and Law are providing assistance to determine what can be done. Also, the governor is taking the issue up with the producers, to see what they are doing, Navarre said.

A question was asked whether it would be possible to ease regulations so that Native people could work on the pipeline on both sides of the border. Several people from the Dot Lake community attended a First Nations conference in Whitehorse in which Foothills Pipe Lines made presentations on construction techniques. It became apparent that pipeline crews using modern technologies will move very fast, building several miles per day. Construction crews will be in the Dot Lake area for just a few days, which would seem to limit opportunities for training and employment in construction.

Council member Charlie Cole said that Harold Heinze, a former state Natural Resources Commissioner and ARCO Alaska manager, had suggested to the Council a free "economic zone" from Delta to Whitehorse where people could move back and forth without red tape. "His thought was that it could apply to all labor," Cole said.

A response from the audience was that only local people should be able to take advantage of a free-movement economic zone, not imported labor.

Co-chair Frank Brown said that local people should be able to tap gas from the pipeline. A small local utility will be needed, but this energy will be cheaper than any other form of energy the state has experienced. The cheapest alternative form of energy will probably be twice as expensive. There is also the possibility that gas will provide an energy source for mine development in the vicinity, through a small spur line to the mine.

Also, at points along the pipeline route there may be possibilities for industries that use gas or gas liquids. Propane could become a small industry, for example. These are potentials, Brown explained.

An observation from one person in the audience was that development of industrial infrastructure could change the community's rural character. Even development of a gas utility or incorporation of a regional government could impose "costs" by changing the character of the community.

Co-chair Brown replied that these were options. The community can decide whether or not to take advantage of access to gas.

A question was raised as to whether Fairbanks was considering natural gas plants, and whether the Tok community could buy products (such as propane) in Fairbanks.

Fairbanks North Star Borough Mayor Boyles, a Council member, replied that her community is looking to expand its economic base and hopes to develop new gas-based infrastructure.

A question was asked on who has the final say on a pipeline route.

Commissioner Pourchot said that the producers, or a consortium planning a pipeline, come to the State with a route application. "We look at it and review it." While the general route is selected by the applicants, the specific route is influenced by state and federal agencies, he said.

A comment from the audience was that in 1979 when the Northwest project consortium (the previous Alaska Highway gas group) was considered a strong project, one of former Governor Hammond's first actions was to set up a socio-economic impact committee of local people, so that local people could decide how to handle impacts of construction. How will the Gas Policy Council deal with this kind of question?

Council member Navarre replied that the subcommittee he chairs is working with economists with the Department of Labor and Department of Revenue, seeking funds to do a socio-economic study to use in the Council's final report. Dept. of Labor is also doing some separate, but related studies, and the Legislature may also deal with this issue.

Fairbanks Borough Mayor Boyles said her community is dealing with estimating socio-economic effects already. The University of Alaska's Institute of Social and Economic Research has been asked to help Fairbanks estimate social and economic effects.

A comment from the audience is that Alaskans' experience with promises of cheaper energy has not been promising. When the Anchorage-Fairbanks electric intertie was planned, studies predicted a lowering of electricity costs in the railbelt. This has not materialized. The construction of refineries in the state has not resulted in less expensive gasoline, either.

Council member Charlie Cole replied that he is incensed about the price of motor fuels in the state. His theory is that gasoline and others fuels are priced just slightly under the cost at Cherry Point, Wash., the nearest large out-of-state refinery (meaning that the Alaska price has no connection with the fact that oil is produced and refined here). Cole said he intends to do everything he can to ensure that local prices for natural gas are tied to a netback pricing scheme (the "netback" price on the North Slope, with tariffs added to move gas to Fairbanks, Tok or some other in-state point).

Skepticism was expressed from the person in the audience, who felt Alaska "already has strikes against us" from the past track record. "How are we to believe the gasline will really bring lower costs for gas when the track record has been the opposite?" He urged the Council to be realistic on this issue when talking with the public.

Co-chair Brown replied that the nature of gas is different than crude oil, which must be refined into usable products. The cost of delivering gas to Tok will definitely be cheaper than delivering it to the lower 48.

Commissioner Pourchot added that local prices will still be affected by overall supply and demand. "We will still see prices influenced by some other market. We won't have cheap gas in an isolated market."

A comment, and a question, from the audience was that local electricity prices were 22 cents/kilowatt hour. Would natural gas bring down electricity costs?

Commissioner Pourchot said there was no way of knowing for now. How we get access to gas, such as the State taking its gas in-kind, could make a difference. It would be a local decision to invest in the gas distribution infrastructure. In a small market, with just a few hundred homes, the economics get tougher.

Ken Freeman, staff to the Council, explained that these meetings are for "scoping," to find out what issues are important to Tok. He explained the Council's organization into subcommittees for dealing with specific issues.

Several comments from the audience followed regarding the cost of infrastructure and gas conversion. One audience member pointed out that hydro power is supposed to be cheaper in the long term, but the heavy up-front capital cost creates higher power rates for consumers in the early years. In Alaska this can be as much as six to eight times the cost of alternative forms of energy. The same may be true, to a lesser extent, with gas. There will be higher initial costs until an investor recoups the capital investment, unless there is a subsidy.

The regional manager for Alaska Power and Telephone commented that their studies indicated that it will cost $40,000 to convert one of the utility's diesel generators to gas. Plus, the generator will be "de-rated" by about a third, which means fueled by gas it generates one third less electricity than if fueled by diesel. This means the utility will have to add an engine and generator to compensate for the de-rating and produce the same amount of power. Plus, there will have to be a diesel-powered generating unit on standby. All together, the costs associated with conversion to gas are estimated at $600,000.

Another audience member commented that because of conversion and infrastructure, and other costs, the gasline could wind up imposing more costs than benefits, at least in the short term. "I'd rather just get my dividend," was the comment.

Council member Mike Navarre replied that his community, Kenai, has seen great benefits from natural gas. When his family arrived in Kenai in 1957 there were 323 people and no gas. Over the years, the availability of gas and the industrial development it brought has greatly benefited the community. "If the gasline runs through here there may not seem to be short-term benefits but in the long term these could be substantial. Some of the short-term costs could be offset if a local government is set up, or perhaps there could be temporary State subsidies."

A question was asked about the feasibility of a tap on the pipeline near Tok, and the minimum size to make a tap economic.

Co-chair Brown replied that the minimum size of tap to be feasible isn't yet known.

A question was asked on whether the State is likely to take royalty gas in-kind.

Commissioner Pourchot replied that the majority of the State's royalty oil share is now taken in-kind and sold to Williams Companies, for the Fairbanks refinery. In the past royalty oil was sold to Tesoro and PetroStar. A factor in the design of the pipeline will be whether the State's one-eighth royalty share will be shipped with the producers' gas to the lower 48, or used in the state.

Co-chair Brown added that one of the subcommittees of the Council is looking at how a tap on the pipeline can be contractually provided for before construction.

A comment from the audience was that during planning for the former ANGTS project in the late 1970s, the proposal was to install taps at the beginning because to put them in later would add costs.

Co-chair Brown replied that new technology allows for a "hot tap" procedure where taps can be installed without shutting down a pipeline.

A question was asked whether the Council's pipeline-related work is being coordinated with Rep. Jeanette James' efforts to see a railroad corridor established in the region.

Commissioner Pourchot replied that the Administration doesn't support James' bill (which is still in the Legislature). The bill provides for lands in a right-of-way to be transferred to the Alaska Railroad, which can then sell off corridors for other uses, such as a fiber-optic cable or a pipeline. The Administration believes the State should establish rights-of-way for these other uses, and not make a large land grant to the railroad and let the railroad manage the additional rights-of-way.

A question was raised whether there would be multiple corridors for all of these or a single corridor.

Commissioner Pourchot replied that one of his department's main projects now is looking at land status questions for a pipeline right-of-way. Foothills Pipe Lines has a right-of-way granted by the federal government from the ANGST project and is preparing an application for a State right-of-way. The railroad proposal is for a study, and there is actually no money yet to do the study, either in the U.S. or Canada.

A question was raised whether the Tok community may have to deal with right-of-way corridors several times, for a pipeline, railroad or utility.

Commissioner Pourchot replied the answer is probably yes.

A question was asked about the economic life of the pipeline.

Commissioner Pourchot said the economics many oil and gas projects are designed around are an expected 20 years of life. However, the pipeline itself, with proper maintenance, could last considerably longer. The estimated gas supplied on the slope could support the pipeline for many years beyond 20 years, he said.

A question was asked if there were any other right-of-ways issued.

Commissioner Pourchot replied that Yukon Pacific Corp. has received a conditional State right-of-way for its route (parallel to the TAPS pipeline to Valdez) and that in the 1980s the ANGTS group received a federal right-of-way as well as some permits. An application for a State right-of-way was prepared.

An audience member recalled that 10 years ago when the Air Force was planning its Backscatter radar projects, which would have included some facilities in the Tok area, an excellent job was done in projecting the long-range local job requirements and posting information in the community.

Mike Navarre, a Council member, replied that his subcommittee was assessing skills available in Alaska and the size of the available workforce. "We'll report what kind of jobs are required, but we won't get down to the community level," he said.

Mayor Boyles, a Council member, summarized what she learned at the meeting:

- Local hire is an issue.
- The ability for the local workforce to work across the border is desired.
- There is concerns for energy costs and the benefits the pipeline could provide in lower-cost energy.
- There are concerns about social impacts and changes to a rural way of life.

Co-chair Brown observed, "I felt like this was one of our better meetings. It was more like conversation. I learned a lot."

Alaska Highway Natural Gas Policy Council

AGENDA

July 19, 2001, 12:30 p.m. to 5:30 p.m.
North Slope Borough Assembly Chambers, Barrow

I. Community Reception, sponsored by the North Slope Borough

II. Public Hearing begins

III. Introductory Remarks, Co-Chairs Frank Brown and Jim Sampson

IV. Remarks from Acting Mayor Margaret Opie

V. Welcoming remarks from Governor Tony Knowles

VI. Remarks by Dept. of Natural Resources Commissioner Pat Pourchot

VII. Invited Presenters

A. North Slope Borough

B. Alaska Eskimo Whaling Commission

VIII. Public Testimony

IX. Full Council meeting

Before the meeting, the Council toured the Barrow gas field and local gas utility facilities. The day after the meeting, Council members toured the Alpine Facility and the Prudhoe Bay Central Gas Facility.

Alaska Highway Natural Gas Policy Council

Barrow Public Hearing Summary
August 19, 2001, North Slope Borough Assembly Chambers

Co-chair Frank Brown opened the meeting, noting the presence of both Governor Knowles and Lt. Gov. Ulmer, as well as many members of the full Council. For the audience, in Barrow as well as listening by radio, he described the Council and its purposes.

Governor Knowles made some opening remarks, indicating that people of the North Slope have helped "set the standards" for projects in the Arctic.

Lt. Gov. Ulmer mentioned her appreciation for tours of the Barrow gas field and local gas utility facilities prior to the meeting. "I had wanted to see how you are using a local gas resource, how a community takes advantage of the opportunity presented by gas. We need to learn how you have balanced subsistence with economic development and retained subsistence while also encouraging appropriate development."

Molly Pedersen, president of the North Slope Borough Assembly, was the first person to speak to the Council. She was representing the mayor, who was in London at the International Whaling Commission meeting.

Pedersen said that people of the North Slope have played an active role in oil and gas development over the past 25 years, a partnership in which the role of the Borough and other organizations has been to enhance the protections of development activity. "At times our insistence on environmental safeguards has been a thorn in the side of industry, but the Borough's role has been important to the state. We are actively supporting lobbying for ANWR development, for example, including giving financial support to the effort. Because our agenda is beyond that of income from oil and gas, we are Alaska's most powerful response to the Gwich'in (an Athabascan group who oppose ANWR exploration) and the environmentalists."

"We bring the same partnership to natural gas. We applaud the governor's early commitment to an Alaska Highway route for the gas pipeline because this route would increase the potential for in-state use, the options for public sector involvement in the project. The North Slope Borough has expressed an early interest in public sector involvement through its membership in the Port Authority. The Borough will now await the conclusion of the Gas Policy Council's deliberations, as well as those by the Legislature's committee, chaired by Sen. Torgerson, and the industry's studies. There are a lot of questions to be answered before a plan to develop the natural gas can be put forward."

Pedersen noted that gas is a clean fuel and that its use will reduce pollution. "My biggest concern is that while development of the gas will be good for the nation and the state, the environmental risks of a large project like this are concentrated on our lands."

Charlie Neokok, a member of the Barrow Whaling Captain's Association and representing the Alaska Eskimo Whaling Commission (AEWC), told the Council that "subsistence hunting is at the core of our culture."

"We recognize that oil development has brought the standard of living in our villages up, although it is even today at a minimum standard compared with elsewhere." Most of the benefits of gas development will go to other communities, mainly in the lower 48, "while our communities will bear 100 percent of the environmental risk."

The AEWC realizes that two routes are under consideration for the gas pipeline. The AEWC supports the onshore Alaska Highway route because it provides opportunities for communities to use gas because it will provide more jobs and because it will add more tax base. "It is important to keep the pipeline onshore. We adamantly oppose the northern route because it would take the pipeline directly through the fall whale migration areas where we hunt. These are important feeding areas."

Of particular concern is the potential disturbance of offshore dredging. "There is no telling how long it will take to recover," from the effects of dredging. The ongoing maintenance activity on an offshore pipeline will also have impacts on wildlife. Research has shown that offshore seismic activity has disturbed whales during migration despite the industry's assurances otherwise. Whaling captains are concerned that an offshore pipeline will create a tremendous disturbance, but that industry, "is driven by greed, and will tell us whatever it takes to get what they want. The Arctic is unforgiving. Life here is fragile."

(Note: An extensive discussion among Council members and an industry representative followed Neokok's remarks. We will summarize the main points advanced.)

Curtis Thayer, representing the gas producers' group working on feasibility and cost studies for the gas pipeline project, described the studies underway now, which include the large gas conditioning plant on the North Slope, various sections of pipeline from Alaska to Alberta, Canada and from Alberta to lower 48 markets, and a natural gas liquids extraction plant located somewhere along the route. He described extensive logistics studies underway, of trucking needs and capabilities of ports through which material will be moved.

The heavy-wall pipe required for a high-pressure pipeline presents special challenges. It is so heavy that only one pipe length can be moved on a large truck, compared with several pipe lengths (of thinner wall pipe) moved on a truck during construction of the trans-Alaska oil pipeline in the 1970s. The high-strength types of pipe being considered have never before been rolled into 48-inch pipe diameters, and the only countries with the technical capabilities of doing this are Japan and Korea. It would take two full years of the steel production capacity of those countries to produce the amount of pipe needed.

The northern route is about 200 miles shorter, but there are questions as to whether it can be done. The industry group is now beginning sonar studies of bottom conditions along the route, to see if it is possible.

In the end, the industry has to have an economic project. "At this stage we don't have an economic project," Thayer said. "The analysis underway now is how to get an economic project. We have not completed the analysis for the three companies. It's like we're building a car. We don't know if anyone will buy it."

Governor Knowles commented that the northern route, on paper, appears less expensive, but this still begs the question of how the concerns of North Slope people can be quantified in economic terms. "What is this testimony (from North Slope communities) worth," (in the economic calculation)?

Carl Marrs, a Council member, asked the industry how it responds to the concerns being expressed at this meeting. "It sounds like they've already got it down to costs per mcf (thousand cubic feet of gas) but I haven't been given any information on the (effects of) trenching, and the safety risks."

Bob Penney, a Council member, remarked that the environmental impact statement for the project must take the human element into consideration along with the cost savings of building 200 miles less pipeline. Penney observed that in 1976 and 1977, during previous debates over gas pipeline routes, it also appeared that a northern route would be cheaper. But it wasn't possible to build. Now, if industry concludes that if there can't be a northern route there might not be a gas pipeline at all, "a lot of Alaskans will say fine, let's just leave the gas in the ground."

Charlie Cole, a Council member, questioned whether the industry group can really say the northern route is cheaper before the ocean bottom conditions and engineering problems are really understood.

Ken Thompson, a Council member, commented that he would not trust a net present value calculation of a pipeline route that has, in reality, little chance of securing permits. The petroleum industry in Alaska has realized billions of dollars of benefits, but coming with that is a responsibility to include the community values in its assessments, which are "a bigger part of the equation than net present value."

Richard Glenn, vice president of lands for Arctic Slope Regional Corp. (ASRC), spoke next to the Council, representing ASRC.

ASRC owns about 4 million acres of lands with prospects for gas, he said, and ASRC's mission is to use its resources to better the lives of its shareholders. ASRC must also balance the material benefits of gas development with its responsibility of environmental stewardship and protection of its lands.

The regional corporation owns lands in the Brooks Range foothills with some of the best prospects for gas in the U.S. One of the corporation's concerns is access to the pipeline for gas produced by non-pipeline owners, and whether a pipeline leaving the North Slope will have adequate capacity for future production of gas.

Access to opportunities presented by a pipeline project is also a major concern for ASRC, including jobs and business opportunities for the corporation's oil service subsidiaries. ASRC's companies have proven their competence and have much to contribute to the project. Glenn noted the involvement of Natchiq, Inc., ASRC's subsidiary, in engineering and design work for the large gas conditioning plant and the "B to C" (Alberta to lower 48) pipeline studies. There has been little discussion so far of who will own the pipeline, however. "We seek to be a part of that. ASRC wants to be there," he said.

ASRC joins the North Slope Borough in supporting an overland pipeline, which will also provide access to the significant resource potential of the central North Slope (foothills) region. "We are confident the producers will come to the same conclusion," he said.

Glenn urged the Council to study Barrow as an example of how gas has benefited a small community. Use of diesel fuel presents risks of an interruption of supply, and risks of spills, where natural gas is more reliable and cleaner. He noted there is a significant capital cost for a community to convert from diesel to gas, however.

Following Richard Glenn, there were comments by telephone from several villages on the Slope. From Atqusuk came comments that, "we've been waiting a long time to hook up to gas," and that the producers should build the pipeline overland, but with regard for caribou. "We live off caribou."

Council co-chair Frank Brown commented that all proposals so far for a natural gas pipeline involved burying the pipeline.

From Kaktovik, Fenton Rexford, representing Kaktovik Inupiat Corp. and its 110 shareholders, supported the comments presented by the AEWC and the North Slope Borough. "This summer the ice has been very heavy between our village and Canada. We watch these conditions closely because our relatives are travelling back and forth," to Canada. Ice ridges are very high this summer.

Mayor Gonzalez, of Kaktovik, followed Fenton Rexford and supported his testimony. He said that Kaktovik's city council had passed a resolution supporting an onshore pipeline route and opposing an offshore route, and supporting the concept of participating in the project through the Port Authority.

From Point Hope, Jack Schaefer said the North Slope Borough is experiencing declining revenues from property taxes that is causing hardship in the villages, because of layoffs and lost benefits. He added that ASRC should be a partner in a gas project.

Willie Neokok, mayor of Point Lay and a member of the North Slope Borough Planning Commission, told the Council he also supported the onshore gas pipeline. He concurred with the comments by Jack Schaefer that there is rising unemployment in the villages and that the gas project represents an opportunity for local people to go to work. He also pointed out that repairs and maintenance to an offshore pipeline would cost more and that salt water could have corrosive effects on pipe.

From Nuiqsut, the village nearest the Prudhoe Bay oil fields, Isaac Nukapigak, president of Kuupik Corp., said his corporation supports new development as long as it is done in an environmentally responsible way. If the pipeline is built by the overland route, there will be more contracting opportunities for Alaskan firms, he pointed out.

Ely Nukapigak, also a resident of Nuiqsut, said the community had sent a letter opposing an offshore pipeline. Cross Island, offshore Prudhoe Bay, is an area of particular importance for Nuiqsut in whaling, he added.

From Anaktuvuk, there was cautious support expressed for the overland pipeline, along with the hope that gas availability would lower energy costs in North Slope communities.

From Wainwright, there were comments that gas production could result in some lost oil production from the underground reservoir. The oil producers should be taking a careful look at this. A question was asked about the kinds of technology that would be available to minimize lost oil production and produce the remaining oil from the Prudhoe Bay field.

The mayor of the City of Barrow commented that the best way to protect subsistence on the North Slope is to build the pipeline down the highway. There is no way to really put a value on lost subsistence, he pointed out.

There is a perception that people of the North Slope have realized a lot of monetary benefits from oil production, through taxes, he said. But this is just a minor fraction of the monetary benefits that others have realized from the oil fields. The gas pipeline will add to the tax base of the North Slope, offsetting depreciation of oil production facilities in the existing fields.

He also hoped the rest of the state would appreciate the position of North Slope communities, so that there is no need to continually have to hire lawyers for the communities to get what is rightfully theirs under existing tax laws of the state.

Charlie Cole, a Council member, asked how important the property tax is to the Borough. The gas producers may ask for property tax relief for their project, he pointed out.

The city mayor replied that the property tax is of utmost importance to the Borough. The North Slope Borough is carrying a heavy debt load from general obligation bonds issued to make local improvements. It is important that the Borough be allowed to continue benefiting from property taxes.

Patsy Aamodt, president of the Native Village of Barrow, told the Council her community wishes no offshore exploration for development of natural gas, and "full funding" of State education funds for schools in the region, "without having to fight tooth and nail." The community supports responsible oil and gas development as long as it's not done in the ocean, she said.

Aamodt mentioned that her son is a certified welder now working in the Milne Point field on the North Slope, and she hopes the highway gas pipeline will provide employment opportunities for him and other young people on the North Slope.

Delbert Rexford, a local resident, told the Council he has served on the local city council as well as on a state oil and gas policy advisory council and has been active in the Alaska Municipal League. He supports the overland route because it can be more easily repaired and maintained, he said. The highway route will also bring important benefits to the local communities. North Slope communities are facing economic and social problems, but over the years the State of Alaska has been cutting back on municipal revenue-sharing. The industry has also made great strides in reducing environmental impacts and its "footprint" on land with its new projects, but these advances also reduce the tax base for the North Slope Borough.

Rex Okakok, director of planning for the North Slope Borough, submitted written comments to the Council.

Edna McLean, president of Ilisagvik College, said her institution has looked at the options for North Slope gas and believes all Alaskans should support the highway pipeline route. This route represents the greatest opportunity for jobs with the least disruption of the environment. Ilisagvik has successfully developed training programs in a variety of fields, ranging from heavy equipment operation to computer training. The college also helps students who have not completed high school to get their GED and to improve english and math skills. Virtually all graduates of Ilisagvik are able to get good jobs upon graduation. Ilisagvik is ready to work with developers of a highway gas pipeline in training, she said.

Ben Nageak, former North Slope Borough mayor, told the Council he opposes offshore development and considers onshore development as the only prudent way to develop oil and gas resources. Nageak said he was proud of his role, when he was mayor, in helping form the Alaska Gasline Port Authority, with the assistance of Jim Sampson, former Fairbanks borough mayor and now co-chair of the Gas Policy Council, and former Valdez Mayor Dave Cobb. The Port Authority could be an important tool for developing and marketing Alaska gas, and Nageak hoped its formation encouraged the producers to begin their own studies of building a gas pipeline.

Marie Adams, vice president of Arctic Slope Native Association for health services, said her association oversees operations of the 35-year-old public health hospital in Barrow. She urged the Council to consider how important subsistence is in the diet and health of Native peoples. Studies being done in the Nome region are showing that subsistence foods can be important in restoring peoples' health who are afflicted with diabetes and heart disease.

Adams expressed concern about effects of construction of an offshore pipeline on beluga whales, which are important as a subsistence resource for communities in the Mackenzie Delta. The beluga whale population in the Beaufort Sea may range far more widely than is thought, and effects on the population may affect villages in Alaska.

Ned Aerie is a subsistence hunter who travels many miles to get food for his family. He is concerned with the movement west of onshore oil and gas activity into the NPR-A because of contaminants and effects of seismic activity on caribou. He opposes offshore activity because the industry has not demonstrated it has adequate plans for cleanup in the difficult ice and wind conditions of the Beaufort Sea. He also opposes an offshore pipeline because there have been no studies of its feasibility or environmental impacts. He expressed concern over high fuel prices on the North Slope and the unfairness of paying prices far higher than paid by consumers thousands of miles away, "when this is where the oil comes from."

Charlie Cole, a Council member, agreed with this. In Fairbanks people pay over $2/gallon for gasoline when it is manufactured in a refinery 10 miles away, from crude oil from the North Slope, he said. He expressed concern that the same thing may happen if a gas pipeline comes near Fairbanks. "We've got to take a stand on this," he said.

Price Brower, director of the North Slope Borough Search and Rescue, said the borough research and rescue services have often been called to assist in support of oil field and trans-Alaska pipeline operations. The unit is available to assist with gas pipeline-related work, he said.

Rex Peter, a stockholder in ASRC, urged the Council to emphasize that the highway route is best for the gas pipeline because it helps the most people in the state. He also expressed concern that many people speaking to the Council today were bringing up subjects of no direct relevance to the policy issues before the Council.

Johnny Brower, a resident, expressed deep concerns to the Council about alienation felt by many North Slope people over changes thrust on the region by economic decisions made far away. He considers himself a "non-U.S. citizen" but still a Native American, and is proud of it. He feels frustrated because despite opposition of local people to many types of development over the last 25 years, there is still drilling. "You're forcing it on people who don't want to accept it," he said. "We don't want sickness, anger and anxiety. We want to live a healthy, well-balanced life with the proper resources."

Lucy Leavitt, a resident, described her own family's experience with public services, to illustrate the importance of property taxes to the Borough. She and her husband built a home for their family and were fortunate enough to be hooked up to electricity and gas, but not underground sewer and water. They pay 12 cents per gallon for delivered water and pay to have sewage taken away by municipal services. A few years ago the underground sewer and water system was extended to a block from her home. People there now pay $69 per month for unlimited water. She petitioned the Borough to have sewer service extended but was told the extension would cost $10 million and there is no money for it. Property taxes are the only way the Borough has to pay for such services, she told the Council. The issue has immediate and serious consequences for her family. When problems developed with the sewage tank in December, the family had to wait until spring to have it repaired. There were delays in getting the repairs made, and raw sewage leaked out around the house and created health hazards for her two young children.

Alaska Highway Natural Gas Policy Council

AGENDA

August 2, 2001, 10:15 a.m. to 6:00 p.m.
Juneau Baranof Hotel

I. Subcommittee Session #1
   A. Alaska Hire (AJ Room)
   B. Federal/International Action (Room 307)

II. Lunch Break

III. Subcommittee Session #2
   A. Environmental Considerations (Room 307)
   B. Access to Instate Gas and Future Opportunities (AJ Room)

IV. Break

V. <u>Public Hearing</u>

   A. Opening remarks by Co-Chair Jim Sampson

   B. Welcoming remarks by Mayor Sally Smith

   C. Remarks by Governor Tony Knowles

   D. Presentation from DNR Commissioner Pat Pourchot

   E. Public testimony

Alaska Highway Natural Gas Policy Council

Juneau Public Hearing Summary
August 2, 2001, Baranof Hotel

Co-chair Jim Sampson convened the meeting. A moment of silence was held in memory of the passing of Rosemarie Maher, a Council member who was president of Doyon, Ltd., who recently passed away in Fairbanks.

Juneau Mayor Sally Smith welcomed the Council to the capital city. She was pleased that a public hearing on an issue of such statewide importance as natural gas policy would be held in her community.

Governor Knowles made introductory comments, indicating that the natural gas pipeline will help pull Alaska together because its benefits will be seen in many parts of the State. Southeast Alaska has a contribution to make as a staging area for equipment and supplies being moved to construct the highway gasline, the governor noted.

State Resources Commissioner Pat Pourchot gave a presentation on the proposed pipeline and changes in U.S. gas markets that now make it a possibility.

Michael Hurley, representing the North Slope gas producers working on the pipeline, gave an overview of the consortium's summer work, including its assessment of two routes and goal of completing cost estimates and other analyses by the end of the year, to be ready to apply for permits.

Fairbanks Mayor Rhonda Boyles, a Council member, asked Hurley if the "message" the Council heard in Barrow, concerning deep opposition to the northern, offshore route, was received by the producers group.

Hurley replied that it had. "The message we're getting from Alaskans is clear and consistent," he said.

Governor Knowles asked that the producers add "subsistence protection" to their list of goals for the project, along with environmental protection, an economic project and other goals.

Rep. Ethan Berkowitz asked why the liquefied natural gas (LNG) export option is not included among the options.

Hurley replied that a separate industry consortium, the LNG "sponsor group," is working on this. BP and Phillips, two of the three members of the producers' group working on the lower 48 pipeline, are also involved in that effort. ExxonMobil, the third member of the lower 48 pipeline group, has participated in past studies on the LNG option. At this time the lower 48 pipeline looks like the "most likely" way to commercialize the gas, Hurley said.

Charlie Cole, a Council member, asked if the decision between a highway and northern, offshore route would be made mostly on economic grounds.

Hurley replied that economic considerations are probably the most important factor at this point.

Esther Wunnicke, a Council member, asked if the producers' views of the economics are affected by whether or not they are owners of a gas pipeline.

Hurley replied that their views on the economics would be influenced by ownership.

Council member Bill Corbus asked how the consortium felt about possible State equity participation in the project.

Hurley said the producers are not opposed to State involvement. "We're in discussions with most of the major pipeline companies in the U.S., also," but the first issue to be resolved is whether an economic project can be developed. The ownership structure will be developed later.

At the suggestion of the Council, Hurley briefly described the concept of an "open season," where a pipeline being developed as a "contract carrier" would have a period where gas producers or others could "nominate" future gas for delivery, which will allow the pipeline to be sized for those needs. "Contract carriage" is the common form of legal organization for gas pipelines. This was compared to the "common carrier" organization that is common for oil pipelines, including TAPS, where the pipeline is open to all offers of oil, with "nominations" in effect held every month.

Robert Venables, economic director of the City of Haines, told the Council that the community is in a position to play a major role in support of gas pipeline construction and in marketing of gas. Haines has a deepwater port and, thanks to recent highway improvements, good roads to Fairbanks. There were good reasons why the federal government selected Haines as the starting point for the military fuel pipeline to the Fairbanks area during World War II, he said.

The community has had a number of contacts with members of the producers' group studying logistics issues. Both Haines and Skagway are in good positions to support highway route construction, with Skagway supporting construction from Whitehorse south and Haines supporting Whitehorse north. Haines is also working cooperatively with Haines Junction, in the Yukon Territory. The two communities will be able to work together to provide support services.

Following construction, Haines can be a site for manufacture of gas into LNG for shipment to Southeast communities, and possibly to Pacific export markets. There is a relatively short distance for a "spur" pipeline connection to the larger trunk pipeline.

Council member Brian Davies asked what expansions of facilities are required to accommodate construction.

Venables replied no expansion, or very little, is required. There is ample port capacity and sites for on-land storage and staging. Only minor improvements would be needed.

Bill Leighty told the Council that he represents a small charitable foundation interested in new energy technologies. He urged the Council to consider future possibilities of conversion of methane to hydrogen and future conversion of the pipeline to transport hydrogen. An advantage of this is that carbon dioxide extracted in the hydrogen manufacturing process could be used for enhanced oil recovery. If there are future "carbon credits" allowed for projects that use CO2 instead of releasing it into the atmosphere, these credits would benefit the project. Large markets for hydrogen don't yet exist, he acknowledged, but with prospects for hydrogen use in large-scale application for fuel cells, the market will develop.

Loren Gerhard, executive director of the Southeast Conference, told the Council that the resource industries that have been the mainstay of the economy of Southeast — timber and fisheries — are both suffering, and tourism has not yet grown to the point where it will replace these industries. The Conference, made up of municipalities, other organizations and individuals, sees the highway gas pipeline route as a potential benefit to Southeast through logistics support activity. Haines, Skagway and Juneau are well positioned to serve the project, but it's possible that Ketchikan could even play a role. A spur line to Haines is the shortest route to tidewater for an LNG project, he pointed out.

Tim Sunday, representing the Teamsters Union 959, said construction workers in Southeast hope to work on a highway project. Juneau also hopes to get a crack at work on the project, although Juneau would play a supporting role to Haines and Skagway, he said.

Dave Hunz, a Skagway city council member, told the Council his community has traditionally served as a "gateway" to the Yukon Territory. Skagway has a deepwater port and a road to Whitehorse capable of handling heavy loads.

Fred McCorriston, president of the White Pass & Yukon Railroad, said Skagway is an important logistics and transportation center for the Yukon and has the longshore skills and experienced truck drivers needed for pipeline work. There is an existing ore terminal which can be used.

Sue Schrader, representing the Alaska Conservation Alliance, said the environmental organizations she represents strongly opposes all pipeline routes that invade undeveloped, frontier areas and ecosystems, particularly the northern offshore route. The Alliance is not now supporting any particular route but urges that any project that goes forward meet strict state, U.S. federal and Canadian environmental requirements.

Charlie Cole asked why the offshore route is opposed.

Schrader said the concern is with an "unproven" technology of pipeline burial under the Arctic pack ice. "It could put the whole ecosystem at risk," she said. "We feel the 'over-the-top' route appears to present the most potential environmental impacts."

In response to questions from Council members, Schrader said her groups will be more favorable toward a pipeline route following existing infrastructure. She did mention concerns with talk of "streamlining" regulatory procedures. When this happens, usually the level of public notice and public involvement is reduced.

Resources Commissioner Pat Pourchot explained that the kind of "streamlining" contemplated in the Administration was more efficient functioning. The effort now is to bring all issues to the table early so that resolutions can be worked out. That will save time later.

Schrader replied that the Legislature had enacted two bills including provisions for permit "streamlining" that did affect the level of public involvement.

Frank Brown commented that he had seen national television interviews on ANWR in which the president of the Sierra Club recommended that Alaskans develop natural gas instead of opening ANWR.

Don Etheridge, who represents the AFL-CIO in Juneau, said the labor groups he represents would like to see a spur pipeline built to Haines from an Alaska Highway pipeline, and the economic boost to Southeast Alaska that this would bring. He requested that Southeast workers be included in any training programs related to the pipeline. "Our motto is, hire from home first," he told the Council.

Frank Avezac, who is head of Alaska Interstate Gas Co., told the Council his company supports the Administration's efforts to have the gasline built down the highway. Haines is 150 miles from that route, he pointed out. His company is a utility with approval from the Regulatory Commission of Alaska to supply gas service to several coastal Alaska communities, from Ketchikan to Kodiak. Alaska Interstate is now looking to supply Southeast Alaska from Prince Rupert, B.C., but would welcome gas supply from the North Slope pipeline via Haines.

Jamie Parsons, representing the Juneau Chamber of Commerce, urged the Council to support a spur pipeline to Haines, and asked that a Haines spur be included in future presentations by the Council on options for using gas in the state.

Alaska Highway Natural Gas Policy Council

AGENDA

August 23, 2001, 2:00 to 6:00 p.m.
Valdez Convention and Civic Center

I. Presentation from Dick Peterson, Alaska Gas To Liquids Group

II. Presentation from Shane O'Leary, GTL Program Manager, BP

III. Presentation from Dave Dengel, Alaska Gasline Port Authority

IV. Public Hearing

    A. Call to Order: Co-Chair Jim Sampson

    B. Welcoming Remarks: Mayor Bert Cottle

    C. Presentation: Ken Freeman, Executive Director,
    Natural Gas Policy Council

    D. Public Testimony

Alaska Highway Natural Gas Policy Council

Valdez Public Hearing Summary
August 23, 2001, Valdez Convention and Civic Center

Council co-chair Jim Sampson opened the meeting.

Richard Peterson, president of ANGTL, Inc., gave a presentation on gas-to-liquids potential for Alaska. He briefly outlined his company's proposal, to build a 50,000 barrels/day GTL plant on the North Slope that would batch "clean" GTL diesel and naphtha down the existing TAPS pipeline. This could be a pilot for additional plants, which could be added incrementally as the market for clean diesel expands.

A North Slope GTL project could also enhance the economics of a gas pipeline and increase benefits to Alaska, Peterson said. The GTL project would provide the infrastructure for "batching" natural gas liquids that could be removed from the gas on the North Slope and shipped down the TAPS pipeline. These could be sold to a wider world market through Valdez, and used in Fairbanks, as opposed to the current proposal to ship NGLs through the gas pipeline and market them in Alberta. The market for gas liquids in Alberta, and the U.S. Midwest, is already saturated, he said.

Peterson critiqued two points made in a recent analysis by Cambridge Energy Research Associates (CERA). One is that taking gas liquids out of the gas pipeline in Alaska will weaken its economics. Peterson disagreed with this and said having the liquids available in Alaska would increase benefits to the state. Second, CERA missed an important advantage of fuels made from natural gas rather than petroleum — federal taxes are less on fuels from natural gas. This is worth 31 cents/gallon or $13 per barrel to a GTL diesel fuel, he said. Because of these advantages, Peterson said a GTL plant on the North Slope could pay the State $1.75 to $2 per mcf for its royalty gas, much higher than the netback values discussed for a gas pipeline.

Council member Ken Thompson asked if Peterson plans to use Sasol technology.

Peterson replied that his company was technology "neutral," that any proven GTL technology could be used, but that he does have an agreement with Sasol to license their technology. He pointed out that since Sasol doesn't license their technology to a project they don't participate in, this means that Sasol could be a partner in an Alaska GTL project.

A Council member asked for more information on the TAPS batching and gas liquids possibility.

Peterson explained that batching GTL diesel through TAPS would make batching of other liquids possible. Butanes, for example, are now blending with crude oil in TAPS. If these could be batched and sold separately, they would have a higher value than if just blended with the crude oil. ANGTL's proposal involves using physical "pigs" to separate the liquids in the pipeline.

GTL gives the state another option for using liquids, Peterson explained, by batching the liquids from the slope through TAPS rather than the gas pipeline. If liquids are shipped through a dense-phase gas pipeline, problems are created for anyone wanting to tap the gas pipeline for gas offtake because the liquids must be handled also, creating more cost.

Peterson also said that the three major producers have not put forward GTL as an option because they claim it doesn't have enough value. ANGTL believes the majors have missed the important tax advantages.

A Council member observed that BP is investing $100 million in a GTL test plant near Kenai.

Peterson pointed out that other companies are far in advance of BP and Exxon in GTL technology.

A question was asked about energy loss during the GTL process, that 25 percent to 30 percent of energy might be lost.

Peterson said that if it were looked at as a straight conversion, the process is 70 percent to 75 percent efficient (i.e. 25 percent to 30 percent loss of energy). However, if waste heat from the GTL process were captured and used, and other potentials of the process taken advantage of, such as manufacture of pure hydrogen, the efficiency of Btus in and Btus out is more like 95 percent.

Council member Brian Davies observed that this assumes beneficial uses for the waste heat and other products.

Peterson pointed out that water generated by the project could be used in waterflood, and that nitrogen could be used in enhanced oil recovery.

Council member Peg Tileston asked who is involved in ANGTL.

Peterson said he has a partner, and that Forest Oil Corp. was backing the venture. Mossgas, a South African company that operates a commercial-scale GTL plant, is an advisor and is also interested in becoming involved in an Alaska project.

A question was asked about how much GTL product could be made from North Slope gas.

Peterson replied that he believes the North Slope has the potential to produce 1 million barrels per day of liquid GTL products. More likely is 300,000 barrels per day produced by several GTL plants built in increments of 50,000 barrels/daily, which seems to be the optimum capacity for commercial-scale GTL plants. The project should begin with one plant producing 50,000 barrels/daily, batched through TAPS. This would establish Alaska "clean diesel" in the market, which could then be gradually expanded.

If the State wished to do something with its royalty gas, ANGTL could move forward with a project, Peterson said.

Council member Esther Wunnicke asked about transportation costs.

Peterson replied that his analysis assumed $2.80 per barrel tariffs for the TAPS pipeline and $5 per barrel for marine transportation to the West Coast.

Shane O'Leary, GTL project manager for BP, presented information on BP's project.

O'Leary explained the process as essentially taking methane, the main component of natural gas, and combining it with steam in a reforming process, making a synthesis gas. The second stage is the Fischer-Tropsch chemical conversion, which converts the synthesis gas into paraffin waxes. A third stage is conventional refining, which converts these waxes into different products, such as diesel.

The first stage - reforming - is where 65 percent of the capital cost of a GTL project is, and this is the heart of the BP strategy. GTL is now inefficient. For 100 units of energy in, you get 60 out. A lot of work is being directed at ways of capturing waste heat and lowering the capital cost.

GTL plants that have been built were done for reasons of national interest. Germany built GTL plants during World War II because there was not access to enough conventional oil. South Africa built plants because international boycotts cut them off from most supplies of oil. More recently, Sasol and Chevron are working on a GTL project in Nigeria, but this is mostly to capture gas that is now flared and wasted. What could be the first truly commercial GTL plant is a project planned by Sasol in Qatar. But little is known of the commercial terms of this project, whether there could be subsidies.

BP has been working on GTL since the 1980s, mostly focused on the reformer stage. Their next step is the plant at Nikiski, which will test a new compact reformer, which promises to reduce costs. The test results from the Nikiski plant can be scaled up to a commercial plant.

Other products can be made from synthesis gas produced through a compact reformer besides "clean" diesel, including methanol and fertilizer. Agrium, for example, now makes fertilizer from a synthesis gas made from natural gas through a reformer.

Dick Peterson addressed very well the high quality of products made through a GTL process. The diesel has no sulfur, nitrous oxide or aeromatics (which produce the smoke seen from diesel trucks and buses). There are other products, such as naphtha, a petrochemical feedstock. Naphtha made through GTL has a 10 percent to 15 percent quality differential than conventional naphtha. Jet fuel made from GTL is very high quality, leaving no contrails. Contrails are a serious environmental problem in some areas of high air traffic, such as parts of Europe. BP is looking for ways to make its GTL process economic with a conventional 30,000 barrels/day plant.

The big advantage of GTL is that the plants can be build incrementally, expanding production with the market. This isn't the case with a gas pipeline or liquefied natural gas project, where all the costs are "up-front." The compact reformer technology being demonstrated at Nikiski is proprietary with a partner. "But BP is not hung up on property rights to technology, unlike other major oil companies. We just want to commercialize our gas."

The best Fischer-Tropsch GTL technology is the slurry-bed reactor, like Sasol has developed, O'Leary said. BP is working on slurry-bed technology also.

Today the conventional wisdom is that a GTL plant will cost about $25,000 per barrel of daily capacity, built on the U.S. gulf coast. A 30,000 barrels/day plant would cost about $750 million. BP believes that if costs can be reduced to about $20,000 per barrel of daily capacity, there will be a lot of excitement about GTL. Once these plants are beginning to be built on a mass scale, the cost structure will come down more. BP believes costs can be reduced to about $17,000 per barrel of daily capacity, at which point GTL will be on par with liquefied natural gas (LNG). This is on the gulf coast, however. The rule-of-thumb is that it costs 25 percent more to build a plant on the North Slope, compared with the U.S. gulf coast.

O'Leary said construction of the Nikiski plant required 150 to 200 workers, and that the biggest problem was securing skilled craft labor. BP's target for starting up its Nikiski plant is second-quarter 2002. The plant is intended to operate for five years, but there are many types of testing that can extend the operating life. The facility is designed so that a technology system, such as a new slurry-bed Fischer-Tropsch reactor, can be "plugged in" to the compact reformer. One additional technology now being tested at the plant is a new type of solid oxide fuel cell that could be 30 percent to 45 percent more efficient than conventional fuel cells, and generate one-third less carbon dioxide. BP sees potential for installation of these new fuel cells on platforms and drilling rigs. There could be many other uses as well.

Council member Bill Corbus asked about the cost of Fischer-Tropsch diesel, made through GTL.

O'Leary replied that the environmental properties of the fuel should command a higher price. "But unless you're in a place where a conventional pipeline or LNG won't work, GTL isn't economic." BP still looks at the economics in a "holistic" sense. "We don't see it as economic until we get the costs down. We do think there is a good market for Fischer-Tropsch GTL diesel, but we still need to get costs down. We're almost there. It's right on the cusp. It's really close."

Council member Esther Wunnicke asked about the gas price assumptions used in the economic analysis.

O'Leary replied that a gas price of 30 cents per mcf is assumed. "Even at 30 cents, it still struggles. We've got to get costs down."

Council member Brian Davies asked if BP had taken the tax advantages mentioned by Dick Peterson into consideration.

O'Leary said BP's analysis was without tax considerations. "It's an interesting point that we haven't researched. I'm going to take his paper back," for further review.

Council member George Wuerch observed that if GTL diesel has such clean properties, California would probably offer incentives.

O'Leary said that refiners will say they don't need GTL technology, that they can install desulfurization facilities and make clean diesel more cheaply than through GTL. So, the industry's "downstream" is not enthused about GTL.

Council member Ken Thompson said that at a Girdwood conference on GTL earlier this year he had understood that it will take about 10 years to achieve the 20 percent reduction.

O'Leary said that BP's view is that it will take five years to achieve the reductions. Some interesting new technologies are also being experimented with, such as use of ceramic membranes.

Thompson said he also learned of dramatic cost reductions in natural gas liquids technologies at the Gir..wood conference, which will improve the economics of businesses related to propane and butane. It pinpoints the NGLs as a major issue for Alaska and Alberta.

O'Leary said BP had always said there will be more than one commercialization strategy for gas from the North Slope. The key is to get the first commercialization accomplished, through a gas pipeline. Once that happens, there will be an explosion of activity, exploring for more natural gas. BP ranks the pipeline first, GTL second and LNG third in order of options.

Co-chair Jim Sampson said BP's original plan was to build its test plant on the slope. He asked why this was changed to Nikiski.

O'Leary said because the plant is "stick-built" (built on site, not modularized) it's cheaper to build near Kenai, where there is also a supply of gas and labor is available. It's also closer for the scientific staff, who will be based in Anchorage.

Dave Dengel, acting executive director of the Alaska Gasline Port Authority, welcomed the Council to Valdez and introduced Charlie Cole, who is a member of the Authority's board (as well as a Council member).

Cole described how the Authority was first formed, at the initiation of the mayors of Valdez, Fairbanks North Star Borough and the North Slope Borough, and how it was formed with approval of voters in all three municipalities. The financial concept of the Authority is that it would retain earnings in Alaska, paying 60 percent of net earnings to the State, 30 percent in a distribution to all Alaska municipalities and reserving the remaining 10 percent to the three municipalities which had initiated the Authority.

The Authority built a team of legal, financial and construction advisors and consultants, including Bechtel. The first analysis was on an all-Alaska pipeline to Valdez, with an LNG export project. This was found to be uneconomic. The plan was then shifted to a combined LNG-export and lower 48 pipeline, with six billion cubic feet (bcf) daily produced off the slope and transported to a hub at Delta, where 3 bcf/day would move to the lower 48 and 3 bcf/day would move to a Valdez LNG plant, which would have a capacity to produce 15 million tons per year of LNG.

The cost assumptions included $4.2 billion for a conditioning plant at the North Slope, $9.7 billion for pipelines to Delta and branches to Valdez and the Canada border, and $3.65 billion for an LNG plant at Valdez. The total capital cost would be $18 billion. Adding "soft costs" of $5 billion for interest paid during construction, an owners' contingency fund of $900 million, and $1 billion in debt service, brings financing costs to $7.8 billion, for a total of $26 billion.

"This may not be the best or only project, but it's a start," said Cole.

Co-chair Jim Sampson asked what happens at the Canada border.

Cole said the pipeline obviously would extend through Canada to the heartland of the U.S. He introduced Rigdon Boykin, financial advisor to the Port Authority.

Boykin said the Authority has had several conversations with Foothills Pipe Lines, and a gas tariff through Canada to Chicago is assumed to be $1.20 per mcf based on information from Foothills.

Studies by the Authority show that capital costs per ton of a pipeline and LNG plant would be high, about $740 per ton of LNG produced, but the revenues from a liquids extraction business could offset this, to the point that costs of LNG would be reduced to about $400 per ton. This is in the range of competitiveness with other, competing LNG projects.

The Port Authority proposed to finance the project 100 percent with debt, using a project-financing approach. The financial plan includes a 2.08 debt coverage ratio as a minimum and 2.5 as an average, in terms of revenues over debt. The tax-exemption of the project is worth $3 billion to $6 billion in value to the project, compared to what financing costs for a privately-financed project would be.

Results of the financial analysis show the project able to pay producers 75 cents/mcf for gas on the North Slope. Based on this, the State would receive $371 million per year in royalty and severance tax, $148 million per year for a payment-in-lieu of corporate income tax, and $222 million per year in a direct payment to the State treasury. Separately from this, municipalities would receive $148 million per year. Producers would receive $1.7 billion per year. The analysis assumes a $3 per mcf price for gas in Chicago and $2.50 per million Btus for LNG in Valdez (one mcf roughly correlates to 1 million Btus). The Valdez LNG price assumes a $3.40/million Btus price for LNG delivered in Asi .

One of the primary benefits of a port authority is that is would not be subject to Federal Energy Regulatory Commission (FERC) regulation. This is based on an exemption from FERC review in the federal National Gas Act, exempting public entities from regulation. The State of Alaska would have regulatory control over the project.

Co-chair Sampson opened the public hearing portion of the meeting.

Mayor Bert Cottle welcomed the Council to Valdez. He pointed out that state revenue sharing to local governments has been reduced from $110 million per year to about $30 million. The Port Authority has developed its plan and put it out for public review, and no one has yet come up with a better plan. "Let's have no more studies, no more politics. The best way to kill a project is to study it." The gas on the North Slope is Alaska's gas. "It's time we stood up to take care of Alaskans first." As for the producers, it's "use it, lose it or tax it." If the producers' study comes back to show that only the "over-the-top" (northern) route is economic, "then we should say, no gas."

Ken Freeman, executive director of the Council, gave a prepared presentation on the proposal for a North Slope gas pipeline and the evolving market for Alaska gas in the U.S.

Curtis Thayer, representing the producers' group working on gas pipeline studies, gave a prepared presentation on the producers' project.

At the conclusion of Thayer's presentation, Council member Jerry Hood asked Thayer why "economics" is always listed as the top criteria for the study, and why "use of gas" as a resource by

Alaskans isn't listed among seven criteria. It gives the impression that economics is the number one consideration, he said.

Thayer responded that benefits to Alaskans is one of the criteria for analysis.

Council member Ken Thompson noted that the presentation speaks only of lower 48 markets, and that Alaskan markets for gas or gas liquids are not mentioned.

Thompson went on to comment that there is more to an analysis than consideration of market forces. An example is ARCO's consideration of double-hull tankers with redundant steering and engine systems, for added safety. "The present value calculation was higher without all that extra stuff, but we chose a path that included the environmental concerns of Alaskans. It was the right thing." The gas pipeline is a complex issue, and a "leader" is needed to step forward, he commented.

Council member Peg Tileston asked Thayer if anyone is making 52-inch high-pressure pipe.

Thayer said that no steel producer was making pipe of this type, as of yet.

Council member Charlie Cole noted that the 1977 U.S.-Canada agreement on the ANGTS stipulates that gas will be made available to remote communities in the Yukon Territory. Are the producers willing to make similar commitments in federal legislation?

Thayer said the producers are very supportive of supplying gas to Alaska communities in the vicinity of the pipeline, but how this gets done is up to the communities.

Council member Jerry Hood said he would like it said for the record. "You are in support of Alaska gas to communities but you don't want it in legislation. What are you in support of?"

Thayer replied that the issue is inappropriate for legislation, but is an important statement of principle.

Cavan Carlton, of Williams Energy, described his company's activities in Alaska and a study underway of manufacturing petrochemicals from North Slope gas at the company's Fairbanks refinery. *(Note: a more complete presentation on this project was made in the Council's September 25 Anchorage meeting and is in the summary prepared for that meeting.)*

Dell Wilson, of Copper Center, told the Council he is president of Ahtna Construction, which is currently a major contractor to Alyeska Pipeline Service Co. Ahtna supports a pipeline through Alaska to Valdez, he said. An "over-the-top" northern pipeline would not benefit Alaskans.

Robert Wilkinson, representing Copper Valley Electric Association, told the Council his association supports a gas pipeline to tidewater. Electricity now costs 16.4 cents/Kilowatt hour in Valdez, double the average cost in the state's "railbelt" communities. A gas pipeline to an LNG plant in Valdez would not only make gas available for local electrical generation, but waste heat from the Valdez plant would further reduce costs.

Bill Walker, city attorney for Valdez but speaking for himself, said he was born in Fairbanks and has lived for much of his life in Valdez. He worked on the TAPS project and saw its benefits first hand. He has been active in efforts to commercialize gas ever since the TAPS pipeline was completed.

Walker said his biggest concern is that the producers will find that only an "over-the-top" route is viable, or that neither the highway or "over-the-top" route is viable. Yet there is a market for the gas, and what's needed is a consortium of purchasers of the gas to team with pipeline companies to build a project if the producers don't want to do it.

CERA has pointed out that if an Alaska project is delayed to the point that the present market window closes, there may not be another opportunity for Alaska gas for 15 years.

Scott Heyworth, proponent of a trans-Alaska gas pipeline and LNG project, told the Council he is supporting an initiative campaign to encourage a trans-Alaska pipeline because most Alaskans want it. The new bill gas producers have circulated in Washington, D.C. would centralize too much power on gas issues in the President's office, and would not provide for use of the gas in-state.

Dave Dengel, city manager of Valdez, said the city has been involved in efforts to build a trans-Alaska gas system for many years. The LNG export project would have wide benefits throughout the state, including Southeast and Southwest Alaska. The port authority concept would benefit many Alaskans.

John Devens, a Valdez resident, said he is not convinced by the producers' statement that if an "over-the-top" northern pipeline is built, a separate pipeline to Fairbanks to serve Alaskans will be built. He urged decisive action to "send a clear message" that Alaskans want a project that will benefit them.

Lynn Chrystal, a Valdez resident, said the Port Authority has made a big improvement on the Alaska Highway pipeline proposal, with a "Y" system that would bring a spur line to Valdez. A northern route, on the other hand, "is like sending all of our salmon Outside."
"If the big companies don't want to play, we should find someone who will," he said.

Rep. John Harris, state representative for the Valdez region, told the Council the Legislature has enacted a law that prohibits an "over-the-top" route. He said a gas pipeline through Alaska would make processing of the resource possible. Also, Yukon Pacific Corp. has signed a Project Labor Agreement, and the Port Authority anticipates signing one. The State's priority should be to have as much infrastructure in Alaska as possible.

John Downes, representing the Copper Valley economic development council and chamber of commerce, expressed support for the Port Authority concept. "It seems doable." He urged the Governor to work with the Port Authority in developing the project.

Pat Abney, an Anchorage resident, told the Council she supported an Alaskan route. She has been an Alaska resident for 40 years and recalls the 1964 earthquake, when Alaskans pulled together to face a big challenge.

Alaska Highway Natural Gas Policy Council

AGENDA

September 7, 2001, 9:00 a.m. to 4:00 p.m.
Anchorage Sheraton Hotel

I. Federal/International Action Subcommittee *(Yukon Room)*

Foothills Pipelines
John Katz & Bob Loeffler

II. Full Council meeting *(Ballroom A)*

Subcommittee Updates
Discussion

III. Environmental Considerations Subcommittee *(Yukon Room)*

Alaska Highway Natural Gas Policy Council

Anchorage Meeting Summary
September 7, 2001, Anchorage Sheraton Hotel

Council co-chair Jim Sampson opened the meeting.

Lt. Gov. Fran Ulmer made opening remarks. Despite press reports about the producers' concerns about a mandate of a pipeline route, the governor is continuing to work with the producers, she said. Ulmer outlined Gov. Knowles' 10-point proposal for federal legislation, which would designate the Alaska Highway route as the approved route and would include federal tax incentives to help the project.

Mike Navarre, chair of the Council's Alaska Hire/Buy/Build Committee, briefed the Council on meetings his committee had with Department of Labor and Department of Community and Economic Development staff on an Administration study of socio-economic impacts that is now underway. The producers' group is nearing completion on a socio-economic study and will present their information at the Council's next meeting. Navarre shared some preliminary information he was given by the producers' group.

He said his committee is considering recommending that a pipeline proponent make commitments on Alaska hire and training, similar to those made in the BP-ARCO charter commitments. One issue the committee is still grappling with is how to ask for commitments to use Alaska companies and contractors.

Bill Corbus, chair of the State Ownership Committee, reported his committee has held four meetings, two shorter sessions coinciding with full Council meetings, and two separate, longer sessions in which the group talked extensively with experts, including a consulting firm retained by the State to analyze the benefits of possible State equity in a gas project.

Corbus said the committee has identified four ways the State can finance an equity investment: through the Permanent Fund; the Constitutional Budget Reserve; the State issuing general obligation bonds; or sale of revenue bonds through the Alaska Industrial Development and Export Authority (AIDEA), or an AIDEA-type authority created to do the gas project financing. The committee reviewed State oil and gas tax policy with the Department of Revenue, focusing on tax structure (Alaska's taxes are both regressive and "front-loaded") and how that might affect a large gas project. The panel has not yet heard from the producers on taxes, however.

Corbus said the committee is likely to make recommendations both on a possible percentage of the pipeline the State might consider owning and the geographic area of participation, such as the section of pipeline from the North Slope to a major offtake hub in Fairbanks or Delta. Under a scenario where the producers choose not to participate, the committee will have an alternative recommendation for the State to work with an independent pipeline group.

In response to questions from the committee, Corbus outlined the main reasons why State equity should be considered: 1) it would create better control over the sale of State royalty gas; 2) it would ensure that other developers would have access to the system for transporting gas. Corbus said he did not believe the investment would make a lot of money for the state (i.e. there might be better alternative ways of using the money) but other members of the committee have not yet weighed in on this.

Ed Rasmuson, a member of the committee, commented that he believed the committee is leaning toward a recommendation that the State make the investment. Corbus agreed. Rasmuson also commented that State investment would be a way for the State to know what's going on inside the pipeline consortium, an important advantage. Dave Rose, another member of the committee, commented that if the investment could earn 15 percent or greater, as seems possible, the return would be in the range that Permanent Fund Trustees might consider it.

Charlie Cole, chair of the Federal/International Action Committee, briefed the Council on meetings his committee has held.

In a meeting in Juneau, John Katz, the state's Washington representative, and Bob Loeffler, an attorney on contract with the State, gave the committee their views on legislation being proposed by the producers. Katz "doesn't think much" of the producers' bill, Cole said, because it aims to somewhat duplicate the expedited regulatory review process established two decades ago in ANGTA for the highway route. Under the amendments proposed to the Natural Gas Act, the Federal Energy Regulatory Commission (FERC) would have no choice but to issue a certificate to the producers group once certain conditions were met. Since the language is "route neutral" (it doesn't designate a route), in effect the provisions would allow the producers to control the choice of a route.

In a committee meeting Sept. 7, held just before the full Council meeting, another problem was discussed in some depth: a potential $4 billion liability on an Alaska Highway project pursued by Foothills Pipelines due to past investments by partners who withdrew from the project. Ken Thompson, a member of the committee, told the Council he believes this issue must be ironed out before the State can support Foothill's application. Cole said that as long as this issue is out there, there will be uncertainties as to how it will effect the pipeline tariff.

The committee will also be taking an in-depth look at how existing lease agreements governing the producers' responsibilities to make gas available for sale are affected by various proposals. For example, if an independent pipeline group were to propose a project, what would be the producers' responsibility to make gas available under existing lease contracts with the State?

Ken Thompson briefed the Council on the work the Access for In-state Gas Use and Future Opportunities Committee has been doing, including review of work related to in-state gas demand studies now underway by consultants to the State.

The committee is also looking at ways of delivering gas to rural communities, including possibilities of shipment of propane and butane as an alternative for communities at a distance from the pipeline. One problem that has been identified is that this pipeline will operate at high-pressure, carrying natural gas liquids with the gas. If there is a "tap" in the pipeline to supply a community, the liquids will have to be extracted from the gas before it can be used, creating additional costs. It may be that gas will have to be taken out at only one or two hubs where the liquids can be economically processed.

The committee reviewed State royalty-in-kind policy and has met with Texas state officials on how they handle their royalty-in-kind. The advice they got was not to "negotiate away" the right to take royalty gas in-kind. Regarding transparency in pricing, it is important for the State to sell some royalty gas in the market to gain information on pricing. Regarding access for gas off-take, it is clear through studies by CERA and others that the Alaska Natural Gas Transportation Act (ANGTA) has very clear language regarding rights to access. If the ANGTA law is not used for a pipeline, similar guarantees can be obtained through FERC proceedings or, as Texas does it, through the right-of-way lease process for state lands. Access into the pipeline is a more serious issue. If the pipeline is operated as a contract rather than common carrier, there are uncertainties. The committee is still looking at this, Thompson said.

Regarding other gas use options, the economics of liquefied natural gas (LNG) still look doubtful but Yukon Pacific Corp. has an active project and if a hub is available, an LNG project may yet materialize. Gas-to-liquids (GTL) is an option but improvements in technology will take 5 to 10 years to make GTL commercial. In the meantime, there are substantial advances occurring in cost reductions of natural gas liquids processing. Williams Energy is seriously studying a large liquids plant that would be an addition to their Fairbanks refinery.

Peg Tileston briefed the Council on work the Environmental Considerations Committee is doing. Several meetings have been held with the Departments of Fish and Game and Environmental Conservation, Division of Governmental Coordination and the Joint Pipeline Office. The committee is focusing on broad policy issues rather than specifics, such as access to information and early consultation with communities on large projects. Once design and engineering has started, it is too late to get significant community involvement, she said.

The committee is also concerned with whether adequate funding is available to agencies reviewing pipeline applications, and problems, particularly for State agencies, in recruiting staff.

Alaska Highway Natural Gas Policy Council

AGENDA

September 25, 2001, 8:30 a.m. to 5:00 p.m.
Anchorage Hilton Hotel

I. Access to In-State Gas Subcommittee — *Lupine Room*

II. Alaska Hire Subcommittee — *Cook Inlet Boardroom*

III. Environmental Considerations Subcommittee — *Prince William Boardroom*

IV. Federal/International Action Subcommittee — *Prudhoe Bay Room*

V. Full Council Meeting Call to Order — *Denali Room*

VI. Working Lunch

VII. Federal Legislation/Congressional Update

VIII. Alaska Natural Gas Producers Pipeline Team

IX. David Hall, Deputy Land Commissioner, Texas General Land Office

X. Break

XI. Alaska NGLs and Petrochemicals, Cavan Carlton, Williams Pipelines

XII. Council members comments/discussion

XIII. Business meeting

Alaska Highway Natural Gas Policy Council

Full Council Meeting Summary
September 25, 2001, Anchorage Hilton Hotel

Co-Chair Jim Sampson convened the meeting.

Council member Charlie Cole led an extensive discussion of the governor's 10 points in proposed federal legislation.

Here are the 10 points:

1) Mandate the already permitted Alaska Highway route as the preferred gasline route.

2) Provide access to the gas for Alaska communities for energy and to businesses for new development;

3) Provide access to the pipeline for new discoveries that will keep Alaska's oil and gas industry healthy through new leasing, exploration and production;

4) Expand opportunities for new pipeline participants to include existing producers, pipeline companies, and major Alaska companies such as Arctic Slope Region, Inc., CIRI and Doyon regional corporations.

5) The legislation must include a provision for Alaska and Alaska Native hire;

6) Must include a provision to use Alaska businesses;

7) Must include a project labor agreement for the construction, operation and maintenance of the pipeline, and worker training to prepare the thousands of needed skilled workers.

8) A priority for the use of American and Canadian steel.

9) Federal legislation must find that the Alaska Highway gas pipeline is in the national interest, including the interest of consumers, businesses, organized labor and manufacturers who would help build it.

10) Include economic incentives such as accelerated depreciation, an investment tax credit and gas tax credit to give investors an additional level of confidence.

There was an extensive discussion of the 10 points and debate on several. Speaking by phone from Washington, D.C., John Katz, the state's Washington representative, said a "joint board" approach, as suggested by Nan Thompson, chair of the Regulatory Commission of Alaska (RCA), is the appropriate mechanism to coordinate action by the Federal Energy Regulatory Commission (FERC) and the state's RCA. There is precedent for such joint boards in the telecommunications field.

Ken Thompson, a Council member, said the governor's principle on access to a pipeline allowed for new exploration on the Slope and new gas brought into the pipeline. It's important that FERC understand this so that rulings are not made that hinder access and future exploration.

Anchorage Mayor George Wuerch raised discussion over a provision for preferential "Alaska hire" when all estimates show there will be more than enough jobs for Alaskans, and that construction is now so busy that hiring halls are empty. There should also be a provision providing for pipeline impact aid to communities affected by construction, he said.

From Washington, John Katz said there was precedent for local impact aid in federal law in the Outer Continental Shelf royalty revenue sharing provisions.

Council Co-Chair Jim Sampson acknowledged the state's economy is larger and more mature than when the TAPS oil pipeline was built, and thus better able to absorb impacts, but the Alaska hire provision is still useful to encourage the support of training of Alaskans. Charlie Cole agreed with this, that the provision will encourage the building of skills among Alaskans.

Brian Davies, a Council member, urged the Council to be "careful what we ask for." To ask that the maximum number of jobs be "dedicated" to Alaskans while also asking for impact aid is contradictory and would undercut the credibility of the state's requests in Congress.

Jim Jansen, a Council member, observed that Alaska labor markets are now extremely tight. In his company (Lynden Tranport), "we hire for the stable market and contract out for the peaks in work." The point is that it might be better to hire outsiders to do pipeline work, and let them live in camps, and keep local people in permanent local jobs.

Carl Marrs questioned the provision for Project Labor Agreements and questioned whether this, if applied for operations, would cut out competition from merit shops (non-union).

Jim Sampson relied that if labor support were desired to move the legislation in Congress, a PLA would be helpful.

Mike Navarre, a Council member, questioned the contradiction between the "preference for Alaska businesses" and preference to unionized firms through the PLA requirement.

From Washington, John Katz commented that this was drafted to be similar to the House-passed ANWR bill, which includes a PLA provision, except that this would focus on construction while the ANWR PLA, in the House bill, includes operations. Katz noted that for a period of years TAPS oil pipeline maintenance and operations work was done under a PLA.

Navarre acknowledged the need for labor's support to get the legislation through, but still felt there was a contradiction between a PLA provision and a preference for Alaska business.

Marrs suggested that the proposal for training for Alaskans include unions, under a PLA, as well as companies.

There was discussion among the Council members on the potential liability of requests by withdrawn partners for repayment of past investments, an issue which could cloud the ability of the current ANGTS partners to finance the project.

John Katz said the Administration is still waiting to see if the issue can be resolved privately between the commercial interests.

In discussing the overall 10 points, Brian Davies observed that many of the items will add to costs, creating a lower wellhead value of gas. "We're asking for short-term benefits and foregoing the longer-term benefits," of a higher value for the natural gas on the Slope.

Jim Jansen said he objected to the requirement that U.S. and Canadian steel be used. He suggested softening the language to include terms like "if available and reasonably priced."

George Wuerch said he supports the overall legislation but doesn't want to make the 10 points "an ultimatum. All 10 points or else."

Esther Wunnicke commented that the Council should endorse the legislation in principle and leave the wording to others.

Peg Tileston said it was important for Alaska to "send a message" to Congress that the state needed special consideration. "We don't want FERC to put us in a box, treating us like other states."

Ethan Berkowitz said the mandate for a highway route still bothered him. "We haven't disproved the opportunity for a liquefied natural gas (LNG) export project to my satisfaction."

John Katz said the concept of future expansions, including a spur and LNG export project, is embedded in the governor's legislation.

Jack Roderick commented that several of the governor's points are extremely important, such as the mandate of the highway route and the joint board with FERC. He was concerned about adding too many "extras" that were possibly less important.

John Katz replied that there is always a fine line between asking for too little and too much. The 10 principles incorporated the most important concepts that were important both in the nation's as well as the state's interest.

At Charlie Cole's request, the Council voted to support the 10 principles. A majority of the Council voted to support them.

Robbie Schilhab of ExxonMobil Corp. and Joe Marushack of Phillips Alaska Petroleum Co., two of three members of the management committee of the producer's consortium, presented the interim results of the economic evaluation of the project.

The current analysis shows both the northern and southern route to be uneconomic, "at present," said Schilhab. The conclusion is based on early numbers, and the companies are now concentrating on areas where they might achieve cost reductions.

The current plan assumes a northern route of 1,803 miles (to Alberta), a southern route of 2,139 miles. A stand-alone Mackenzie Valley pipeline would be 1,140 miles, he said. The study assumed gas throughput at 4.0 to 4.5 billion cubic feet daily, with the project designed so that volume could be increased to 6 billion cubic feet/day in the future, he said. A 52-inch diameter thick-wall pipeline, operating at 2,500 pounds-per-square-inch operating pressure, is assumed in the study, he said.

Costs of a northern, offshore route are estimated at $15.1 billion, with a longer southern route, through the Interior and along the Alaska Highway, estimated at $17.2 billion, he said.

The "tariff," or the cost for transporting gas from the North Slope to markets in the lower 48, is estimated at $2.39 per thousand cubic feet (mcf) for the southern route and $2.07 per mcf for the northern route.

Cumulative government revenues on both routes were about equal, however, at $66.2 billion for the southern route and $68 billion for the northern route, the analysis showed. This includes revenues to Alaska, Canada, provinces of Canada and the U.S. government. Alaska's share of that would be $22.7 billion for the southern route and $24.1 billion for the northern route.

However, a key part of the analysis that was questioned by Council members was a 15 percent discount rate used in the net present value calculation of cumulative cash flows. The discount rate can be assumed to be similar to an expected rate of return for the project, including gas production revenues.

Thompson said that using a 12 percent discount rate the project might be break-even, and if the benefits of the governor's proposed federal tax incentives and the value of the NGL business are added, "this is a commercial project." Thompson said, "I calculate another $3 billion to $4 billion a year in revenue. There's a big component of this that is undervalued." Thompson said his figures were based on assumptions that the liquids shipped would total 100,000 to 150,000 barrels/day. "Is there something we're missing?"

Schilhab said the analysis does not now include any value for downstream sales of liquids. The producers assume the pipeline will carry about 60,000 barrels/day of liquids.

He said the cost estimates were "unclassified" at this point, meaning they were so rough there couldn't yet be a plus-or-minus percentage given. By the end of the year the group intends to have estimates plus-or-minus 30 percent.

Brian Davies asked if it was customary with large gas pipelines to go to an "open season" (a call for gas nominations) with the project still plus-or-minus 30 percent in cost. Schilhab replied that this might be done with this project, and if costs were on the high side, consultations with shippers would have to be done.

He said that the current producers might have to sign on to the project even with the 30 percent probability, but that non-owners, such as companies now exploring for gas who might nominate future production, could be given an "out" if there were cost increases.

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