# 08-24-16

# ALASKA LNG PROJECT UPDATE

<TARGET><BILL></BILL><SUBJECT>08-24-16 ALASKA LNG PROJECT UPDATE</SUBJECT><COMM>HRES29</COMM></TARGET>

# ALASKA STATE LEGISLATURE
## SENATE RESOURCES COMMITTEE

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## Joint Senate & House Resources Committee Meeting

**Wednesday, August 24 and Thursday, August 25, 2016 1-4pm**
**Anchorage LIO Auditorium**

## Agenda

**Wednesday:**

- Steve Butt, AK LNG Project Manager
- Wood MacKenzie, David Barrowman
- Keith Meyer, President, AGDC

**Thursday:**

- Legal Discussion of State Tax-Exempt Status
- Producers: ExxonMobil, ConocoPhillips, BP Alaska
- Nikos Tsafos, enalytica

**This is a listen-only, invited testimony informational meeting.**

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March 23, 2014

VIA E-Mail
Alaska State Legislature
Budget & Audit Committee
State Capitol, Room 514
Juneau, Alaska 99801

Re: The Alaska LNG Project

We have been asked to advise the State of Alaska ("State") on whether there are risks, and ways to minimize any such risks, under the federal antitrust laws in connection with the proposal for the State and four others to create a joint venture that would transport gas and produce LNG for consumption within Alaska and for export by ship to other markets.

In rendering this advice, we are primarily relying on information contained in (i) the Heads of Agreement dated January 14, 2014, among the State, the Alaska Gasline Development Corporation ("AGDC"), TransCanada Alaska Development Inc., ExxonMobil Alaska Production Inc., ConocoPhillips Alaska, Inc., and BP Exploration (Alaska) Inc. ("HOA"); (ii) the Memorandum of Understanding among the State, the TransCanada Alaska Company, LLC, Foothills Pipe Lines Ltd. and TransCanada Alaska Development Inc.; (iii) House Bill No. 277, introduced January 24, 2014; and (iv) the Senate Bill No. 138, also originally introduced January 24, 2014, but apparently subsequently modified.

Under the Heads of Agreement and HB 277, the Legislature is proposing to create a new a new AGDC subsidiary, AGDCS, to explore the feasibility of, and to develop, a large diameter gas pipeline from the North Slope and a LNG production plant in Southern Alaska.[1] Like its parent, AGDCS would be "a public corporation and government instrumentality for administrative purposes of the corporation, but having a legal existence separate from the state." [SB Section 7; HB Section 7] The Board of Directors would consist of the corporation's chairman, two state commissioners, and four public members selected by the Governor and

[1] We understand that a prior version of SB 138 also contemplated that AGDC would incorporate a new subsidiary. That feature is not contained in the current version of the Senate Bill. In any case, the existence of a separate subsidiary to AGDC does not affect the analysis contained herein.

serving at his pleasure. AGDCS would be one of the five corporate participants in the project; the other four are TransCanada Alaska Development Inc., ExxonMobile Alaska Production, Inc., ConocoPhillips Alaska, Inc., and BP Exploration (Alaska) Inc. (the latter three collectively "the Producers") (*see* HOA).[2]

This project is generated by the need for the State and the Producers to respond to the changing market for natural gas in North America, largely as a result of the recent economical development of significant gas reserves from shale. This development has substantially increased the amount of gas already being supplied in the United States, and thereby made it uneconomic to build the previously planned Canadian natural gas pipeline from the North Slope to the Lower 48 US states. The Producers have large reserves of natural gas, and the State shares their strong interest in finding markets for it. This reality has led the State to join with the producers to develop the concept of (i) an 800 mile joint venture pipeline from the North Slope to southern Alaska and (ii) a large scale LNG plant and related facilities to convert the gas into a form that could be exported by ship, while also providing for distribution to Alaska residents in the more populous southern part of the State.

We believe that this large-scale, capital intensive project can be justified by applying the normal antitrust analysis contained in the Sherman and Clayton Acts; and any antitrust risks that remained could be eliminated by strengthening the legislative mandate to be sure that whole LNG project could be qualified for immunity under the so-called "state action" doctrine.

**Antitrust Issues Related to the Creation of the LNG Joint Venture**

There are generally two sets of antitrust questions that must be examined when a joint venture is being created: (1) Is the joint venture undertaking an activity that its members could not perform efficiently on an individual basis? (2) Is the size of the venture appropriate to its goals? In the case of the proposed Alaska LNG joint venture, the answers to these questions are clearly "yes".

Where the joint venture is performing what the members have previously done on an individual basis, it may be treated as a de facto merger and hence struck down if it encompasses an unnecessarily high proportion of market participants. See, e.g., *United States v. Columbia*

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2 We note that, to the extent that AGDC/AGDCS would become an owner of a newly created entity or otherwise acquire interests in an entity to develop, own or operate an LNG plant, the acquisition of such interests could potentially implicate the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended. 15 U.S.C. § 7a. This statute is a notification statute which requires parties involved in certain acquisitions of voting securities or assets to notify the federal government before consummating such acquisition. At present, we do not seem to have sufficient information to advise the State on whether any such notification would be required, or if an exemption from such notification would be available.

*Pictures Industries, Inc.*, 507 F. Supp. 412 (S.D.N.Y. 1980), *aff'd mem.* No 81-6003 (2d Cir. 1981). Alternatively, it may be treated as a thinly-veneered cartel, engaged in joint price fixing or market division. See *Timken Roller Bearing Co. v. United States,* 341 US 593 (1951); *United States v. Dynalectric Co.*, 859 F.2d 1559 (11th Cir. 1988). This problem does not appear with regard to the Alaska LNG joint venture. Pipelines and LNG production plants are subject to very large economies of scale. We are not aware of any evidence that any entity has plans to build a pipeline and LNG production plant on their own. And, given the regulatory approvals required for such a project, there appears to be no efficient way to meet the need to transport the gas except via a very large diameter pipeline that is being proposed. It would seem highly unlikely that the State (or the federal government) would approve for environmental and other reasons the building of multiple pipelines and LNG plants. Thus, single, larger scale facilities are perhaps the only practicable alternative to transport and market the North Slope gas.

The situation is quite different if a joint venture among some competitors is performing a necessary and efficient function, and the existing members exclude their rivals from access to the venture. Then the joint venture may be found to have engaged in a form of illegal boycott under Section 1 of the Sherman Act. See *United States v. Terminal RR Assn. of St. Louis*, 224 US 383 (1912); *Associated Press v. United States*, 326 US 1 (1945); *United States v. Realty Multi-List*, 629 F.2d F.2d 1351 (5th Cir. 1980). In these cases, the normal remedy is compulsory access for the non-member competitors. But this problem does not appear present with proposed Alaska LNG joint venture either. The Producers are major sources of natural gas from the North Slope and there is no evidence that there is any other gas producer who has been denied participation in the project. As long as the joint venture pipeline is willing to transport the gas of any smaller producers on reasonable terms, there is simply no antitrust issue with basic creation of the LNG joint venture. Such conditions appear to be reflected in the HOA where it specifically states that the State share of capacity would be owned and operated "on terms that would provide access for third-parties." HOA, ¶ 6.3b.

**1. Antitrust Issues Concerning Operational Rules of a Joint Venture**

There has been a lot more antitrust litigation over how joint ventures actually operate than over their creation. A rule or decision of a joint venture will be treated as an "agreement" among its participating members and therefore subjection to more stringent antitrust scrutiny under Section 1 of the Sherman Act than a single firm monopolist would be for doing the same thing. *See American Needle v. NFL*, 130 S.Ct. 2201 (2010). However, it has become clear that, where the joint venture is performing a function that involves some plausible efficiencies, that its rules and decisions will be adjudicated under fact-intensive balancing process embodied in the so-called "rule of reason", rather than a per se prohibition. *See NCAA v. Board of Regents,* 468 US 85 (1984). Thus the joint venture can set the prices and terms when it is offering a product that is based on competitively produced inputs from its members. *See Broadcast Music, Inc. v. Columbia Broadcasting System, Inc.*, 441 US 1 (1979).

Reviewing the terms of the proposed joint venture among the State and the Producers, we do not see any rules that cause us immediate antitrust concern. The joint venture, as we understand it, will be the producer of the LNG gas for export and the seller of natural gas to the utilities serving consumers in Alaska. It will be free to set prices, quantities and terms for delivery without facing unusual antitrust risks. *Texaco Inc. v. Dagher*, 547 U.S. 1. In addition, the prices at which gas will be delivered to the venture will apparently be discussed/submitted to the Federal Energy Regulatory Commission for review and approval. *See* HOA, ¶ 6.4a. Such prices will therefore be considered regulated and will be essentially free from challenge under the so-called "filed rate doctrine" which prohibits antitrust damage actions in situations where rates were submitted/authorized by an agency with authority to determine whether the rate was appropriate. *Keogh v. Chicago & Northwestern Railway Co.*, 260 U.S. 156 (1922); *Wah Chang v. Duke Energy Trading and Mktg. LLC,* 507 F.3d 1222, 1226 (9th Cir. 2007).

We have reviewed Appendix A (entitled "Pro-Expansion Principles") to the Heads of Agreement. We believe this has been done in a particularly effective way to avoid antitrust risks. A periodic problem occurs in a monopoly joint venture among competitors if one or more partners can veto expansion as a way to restrict supply and thereby generated supply shortages and higher prices in the downstream market. *See United States v. Pan American World Airways, Inc.*, 193 F. Supp. 18 (S.D.N.Y. 1961), *rev'd on other grounds,* 371 U.S. 296 (1963).

However, in Appendix A, it is made clear that any partner (including the State) may cause an expansion of the pipeline or the LNG plant so long as the Expansion Party will finance the addition and certain other conditions are met. The fact the State is a full partner makes this safeguard even stronger. Assume for some reason that the Producers wanted to hold down the pipeline capacity because they believed that resulting shortfall would result in higher prices for themselves. In these circumstances, the State could still exercise its right to be an Expansion Party, and thereby protect the consumer interests of its residents and voters.

**2. Further Reducing Any Antitrust Risks by Enhancing the Legislative Mandate**

As we have indicated, we do not see significant antitrust risks being generated by LNG joint venture's creation or proposed operation. However, we have also had considerable experience where antitrust claims were made against a joint venture for tactical or anti-competitive reasons. The objector will formulate a "price fixing" or "boycott claim" which may be disruptive and expensive to defend. Because of the substantial expense of defending antitrust litigation, the trouble-making plaintiff can impose serious costs on a joint venture and thus sometimes even cause it to abandon its preferred course.[3]

It is for the purpose of reducing any such risks that we make the following comments on how the proposed legislation *could be* modified to ensure that the LNG joint venture could gain the ability to make a strong "state action" exemption defense if sued by a troublemaking plaintiff or class of alleged victims assembled by some opportunistic lawyers.

First recognised in *Parker v. Brown,* 317 U.S. 341 (1943), the state action doctrine is a judicially-created exemption to the application of the federal antitrust laws where a state has imposed a restraint on competition. The state action doctrine immunizes anti-competitive conduct by private parties if a two-part test can be satisfied: (1) the challenged restraint must be one "clearly articulated and affirmatively expressed as state policy" and (2) policy must be "actively supervised" by the state itself. For entities that are considered the "state" for the doctrine's purpose, the second prong need not be established because the state presumably supervises itself.

Stated another way, in the absence of clear intent by the federal government to the contrary, the state action doctrine specifically allows a state to withdraw a sector of the economy from the competitive forces of the marketplace. As one court of appeals explained, "[w]hile individual anti-competitive acts of state governments may be considered unwise or counterproductive, the decision to make such choices lies within the sovereign power of the states. Congress did not intend to override important state interests in passing the Sherman Act." *A.D. Bedell Wholesale Co. v. Philip Morris Inc.,* 263 F.3d 239, 255 (3d Cir. 2001).

Here, the State of Alaska could make clear that, whatever its other goals and the antitrust risks of the Alaska LNG venture may be, it intends that its legislation and the subsequent operation of AGDC/AGDCS to displace the role of competition in the development and marketing of Alaska North Slope gas.[4] For example, it could make somewhat clearer that the State's ultimate goal in passing HB No. 277 and SB No. 138 is to maximize the revenues from

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[3] *See, e.g.,* Robert H. Bork, THE ANTITRUST PARADOX (1978) ("Litigation can be a particularly effective form of predation. Litigation can often be framed so the expenses to each party will be about the same....Expenses in complex business litigation can be enormous, not merely direct legal fees and costs but in diversion of executive time and effort and in the disruption of the organization's regular activities.") The incentives here may be modified somewhat by Alaska Rule of Civil Procedure 82 which incorporates a prevailing party attorneys' fee rule.

[4] While we do not opine on existing Alaska law, we note that we did not come across a provision in existing legislation that makes clear that the State wants to displace market-based competition with its own market and/or regulatory structure with regard to the marketing of ANS gas.

the production of sale of ANS gas, consistent with the presumed goals of the producers. *But see Alaska Gasline Port Auth. v. ExxonMobil Corp.*, 2006-1 Trade Cas. (CCH) ¶ 75,312 (D. Alaska 2006) (Port Authority could not maintain action against gas producers for failing to supply gas to pipeline because, among other things, of apparent preemption of such actions by Stranded Gas Development Act, Alaska Stat. § 43.82.010, *et seq.*).

By making such goals clear in the legislation, Alaska would virtually eliminate (what we believe in any event is minimal) antitrust risk to AGDC and AGDCS in participating in such a venture. It has the virtue of allowing the state to determine if it also wants to extend such protection to the private parties participating in the Project because to do so, Alaska would need to establish some mechanism to "actively supervise" their activities within the Project to ensure that those activities are consistent with the State's goals in authorizing the Project in the first instance. Such a role could be played by the Board of AGDC/AGDCS, which is comprised of, among others, state officials and public citizens appointed by the governor, or another agency or entity of the State of Alaska, if the State so desires it.

We trust that this letter is helpful in explaining the apparent federal antitrust law treatment of the proposed Alaska LNG Project and related legislation. We would be pleased to expand upon on our analysis should the Legislature or the Committee so desire or to address any specific questions that the Legislature or the Committee may have.

Sincerely,

W. Todd Miller
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March 24, 2014 **Via E-mail**

Alaska State Legislature
Legislative Budget & Audit Committee
State Capitol, Room 514
Juneau, Alaska 99801

Re: Whether the Alaska Gasline Development Corporation's Interest in the Gas Project Contemplated by the Memorandum of Understanding, Heads of Agreement, and SB 138 and HB 277 Would Be Exempt from Federal Taxation
Our File No. 12463-01

Ladies and Gentlemen:

The Legislative Budget & Audit Committee of the Alaska State Legislature has requested advice about the tax implications and antitrust issues associated with the Governor of Alaska's gas pipeline and liquefied natural gas proposal. This letter addresses the tax exemption implications of the proposal, and revises and expands on the letter of March 23, 2014. The antitrust implications of the proposal are addressed in the March 23, 2014 letter of Baker & Miller PLLC.

We have been asked to review: the December 12, 2013 Memorandum of Understanding among the State of Alaska ("State"), Trans-Canada Alaska Company, LLC, Foothills Pipe Lines Ltd., Trans-Canada Alaska Development Inc.("Trans-Canada"); the January 14, 2014 Heads of Agreement among the State, the Alaska Gasline Development Corporation ("AGDC"), Trans-Canada, ExxonMobil Alaska Production Inc., ConocoPhillips Alaska, Inc. and BP Exploration (Alaska) Inc., and the pending enabling legislation, originally submitted as Senate Bill 138 and House Bill 277.

The Memorandum of Understanding, the Heads of Agreement, and the current versions of Senate Bill 138 and House Bill 277 contemplate that the State would take an equity interest in part or all of an Alaska liquefied natural gas project, including design, development, construction and operation of the infrastructure and services required to

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transport, liquefy, ship and market natural gas and associated hydrocarbons, specifically including a Prudhoe Bay unit gas transmission line, a Point Thomson unit gas transmission line, a gas pipeline, a gas treatment plant, a liquefied natural gas plant, and a marine terminal (the "Project"), and involving State ownership of, or participation in, up to 25% of the Project (the "Interest"). (As would be provided in AS 31.25.005(5) and AS 31.25.390(7) (Sec. 2 of CS for Senate Bill No. 138 (FIN) am)).

The purpose of the Project includes developing natural gas pipelines, to deliver natural gas in-state for the maximum benefit of the people of Alaska, to provide economic benefits and revenue to the State, and to maximize royalty and tax revenues from Alaska natural gas. (As would be provided in AS 31.25.005 (Sec. 1 of CS for Senate Bill No. 138 (FIN) am)).

The State's Interest in the Project would be held by AGDC,

> a public corporation and government instrumentality acting in the best interest of the state for the purposes required by AS 31.25.005, located for administrative purposes in the Department of Commerce, Community, and Economic Development, but having a legal existence independent of and separate from the state.

(As would be modified in AS 31.25.010 (Sec. 2 of CS for Senate Bill No. 138(FIN) am)).

AGDC is governed by a board of directors consisting of five public members, appointed by, and serving at the pleasure of, the governor and subject to confirmation by the legislature and two individuals designated by the governor that are each the head of a principal department of the State. AS 31.25.020. The AGDC board shall appoint a program director and executive director for the Project. AS 31.25.040(d) and 31.25.045. The personnel of AGDC are exempt from AS 39.25, the State Personnel Act. AS 31.25.065.

AGDC has been granted the power of eminent domain, exercisable by filing a declaration of taking under AS 09.55.240 - 09.55.460, to acquire land or an interest in land that is necessary for the Project; the exercise of powers by AGDC may not exceed the permissible exercise of the powers by the State. AS 31.25.080(a)(4), as would be modified in Sec. 4 of CS for Senate Bill No. 138 (FIN) am.

The board of AGDC has been granted the power to "adopt regulations to carry out the purposes of [AS 31.25]"). AS 31.25.130(c). AGDC is generally required to post proposed regulations for public comment at least 15 days prior to adoption. AS 31.25.130(d). Regulations adopted by AGDC's board shall be made available to members of the public and to the chair of the Administrative Regulation Review Committee under AS 24.20.400-24.20.460. AS 31.25.130(a).

AGDC has been given access by statute to the information of departments, agencies, and public corporations of the State that is directly related to the planning, financing, development, acquisition, maintenance, construction, or operation of the Project. All departments, agencies, and public corporations of the State are required to cooperate with, and provide information, services, and facilities to AGDC, and are generally required to give priority to processing authorization applications and other requests of AGDC. Further, the Department of Natural Resources is generally required to grant AGDC a right-of-way lease under AS 38.35 for the Project's gas pipeline transportation corridor at no appraisal or rental cost. AS 31.25.090.

The revisions proposed in SB 138 and HB 277 to AS 31.25.110 would authorize a Project fund, established in AGDC and consisting of money appropriated to it. AGDC would be responsible for fund management, but may contract with the Department of Revenue for fund management. If money were appropriated to the fund to finance the cost of the Project, AGDC would create an account in the fund for that purpose and hold the money appropriated for that purpose in that account. AGDC may use money appropriated to the fund without further appropriation for the purpose of managing the fund, for purposes related to the Project, and for purposes of transferring net revenue received to an appropriate fund as determined by the commissioner of revenue in consultation with the commissioner of natural resources.

AGDC has the power to form subsidiary corporations to develop, construct, operate, and finance in-state natural gas pipeline projects or other transportation mechanisms, although this power does not seem to cover owning an interest in a gas liquification plant and/or marine terminal, powers which seem to be reserved to AGDC itself. AS 31.25.120.

## I. Whether AGDC Qualifies as a Political Subdivision of the State of Alaska.

If AGDC qualifies as a political subdivision of the State of Alaska for tax purposes, its income would not be subject to federal taxation, under the doctrine of implied statutory immunity.

> <u>Income earned by</u> a state, <u>a political subdivision of a state, . . . is generally not taxable</u> in the absence of specific statutory authorization for taxing such income.

Rev. Rul. 87-2 (emphasis added).

The income of states and their political subdivisions is exempt from federal taxation because, with one exception,[1] the Internal Revenue Code does not expressly impose a tax on them. States and their political subdivisions are protected by implied statutory immunity, implied from the failure of the Internal Revenue Code to either expressly subject them to, or exempt them from, federal income taxation.[2] *E.g.*, Rev. Rul. 87-2; *Estate of Alexander J. Shamberg*, 3 T.C. 131, 146 (1944), *acq.*, 1945 C.B. 6, *aff'd*, 144 F.2d 998 (2d Cir. 1944), 1945 C.B. 335, *cert. denied*, 323 U.S. 792 (1944).

A political subdivision is a division of the state which has been delegated the right to exercise part of the powers of a sovereign. Id. To determine whether AGDC qualifies as a political subdivision of the State, and under implied statutory immunity is not subject to federal income taxation, the IRS applies the Treasury regulations interpreting § 103 of the Internal Revenue Code. Rev. Rul 77-164; see also GCM 36,994 (Feb. 3, 1977). Under Treas. Reg. § 1.103-1(b), a "political subdivision" refers to "any division of any State or local governmental unit which is a municipal corporation or which has been delegated the right to exercise part of the sovereign power of the unit." Sovereign powers include the power to tax, the power of eminent domain, and the police power. Rev. Rul. 77-164; *Estate of Shamberg*.

The first case to analyze the sovereign powers that a state or local subdivision must have to establish implied statutory immunity from federal taxation was the *Estate of Shamberg*, which concerned the Port of New York Authority ("Port Authority"). *Estate of Shamberg* is particularly important, as the structure of the Port Authority resembles in key respects the structure of AGDC. Specifically, the Port Authority was

> endowed with the power of eminent domain, and with certain police powers, including the promulgation and enforcement of regulations for the conduct of navigation and commerce in the area defined as the Port of New York District.

*Estate of Shamberg*, 3 T.C. at 143.

AGDC likewise has the same two of the three sovereign powers, namely the power of eminent domain and certain police powers. First, AS 31.25.080(a)(4) provides that

[1] Namely, IRC § 511(a)(2)(B) imposes the unrelated business income tax on state colleges and universities.

[2] Implied statutory immunity is different from the constitutional doctrine of intergovernmental tax immunity, which formerly provided substantial protection to states and their political subdivisions from federal taxation. However, the Supreme Court of the United States has in recent decades held that states and their political subdivisions have no broad constitutional protection from federal taxation. *E.g.*, *New York v. United States*, 326 U.S. 572 (1946), and *Garcia v. San Antonio Metropolitan Transit Authority*, 469 U.S. 528 (1985).

AGDC has the power of eminent domain. Second, AGDC has significant police powers–AS 31.25.130(c) provides that the board of AGDC "may adopt regulations to carry out the purposes of [AS 31.25]").

AGDC's power under AS 31.25.130(c) to "adopt regulations to carry out the purposes of [AS 31.25]" is an example of a police power, one of the sovereign powers that can qualify AGDC as a political subdivision (and correspondingly exempt it from taxation). The police power

> embraces regulations designed to promote the public convenience or the general prosperity, as well as regulations designed to promote the public health, the public morals or the public safety.

*Philadelphia Nat'l Bank v. U.S.*, 666 F.2d 834, 840 (3d Cir. 1981), *cert. denied*, 457 U.S. 1105, 73 L. Ed. 2d 1314, 102 S. Ct. 2904 (1982) (quoting *Chicago, Burlington & Quincy Ry. Co. v. Illinois ex rel Drainage Comm'rs*, 200 U.S. 561, 592 (1906)).

*Estate of Shamberg* found that the Port Authority's police powers included "the promulgation and enforcement of regulations for the conduct of navigation and commerce in the area defined as the Port of New York District." As discussed above, AS 31.25.130(c) authorizes AGDC to "adopt regulations to carry out the purposes of [AS 31.25]" Further, AS 31.25 authorizes AGDC to build and own an interest in feeder and transmission natural gas pipelines, and a related LNG plant and marine terminal. In sum, the regulatory power under AS 31.25.130(c) is similar to the regulatory power held by the Port Authority at issue in *Estate of Shamberg* .

All three sovereign powers need not be delegated for AGDC to qualify as a political subdivision for purposes of § 103. Rev. Rul. 77-164, citing *Estate of Shamberg*, states that:

> Three generally acknowledged sovereign powers of states are the power to tax, the power of eminent domain, and the police power . . . . <u>It is not necessary that all three of these powers be delegated</u>. However, possession of only an insubstantial amount of any or all sovereign powers is not sufficient."

(Emphasis added.)

IRS private letter rulings routinely grant political subdivision status to entities that have only one of the three sovereign powers, such as a library district with the power of taxation, a school district with the power of eminent domain, or a health care authority with the power of eminent domain. Ellen P. Aprill, The Integral, the Essential, and the

Instrumental: Federal Income Tax Treatment of Governmental Affiliates, *23 Iowa J. Corp. L. 803, 808-9 (1998)*.

If AGDC intends to qualify for federal tax exemption under implied statutory immunity, it is essential that AGDC retain substantial police (i.e., regulatory) powers under AS 31.25.130(c), in addition to the power of eminent domain. General Counsel Memorandum 37,771 noted that:

> Whatever doubt exists as to exactly what constitutes the minimum amount of required "sovereign power" this Office is unprepared to concede that the possession of only one sovereign power is sufficient. We arrive at this conclusion after considering that the enumerated sovereign powers (taxation, eminent domain, police) can exist in an entity in only a minor degree and recognizing that all the facts and circumstances must be taken into consideration, including the public purposes of the entity and control of the entity by a government.

(Citing *Gen. Couns. Mem. 36,994*, at 7-8.]

Revenue Ruling 73-563 held that a rapid transit authority qualified as a political subdivision under Treas. Reg. 1.103-1 for purposes of issuing tax-exempt bonds because the authority, in part because it had the police power to set rates, determine routes, and enforce its regulations by maintaining a security force, but also because the state legislature empowered participating state governing bodies to levy retail and use taxes to fund the authority and authorized them to exercise the power of eminent domain on behalf of the authority. Likewise, SB 138 and HB 277, together with the statutes they modify, provide that certain State agencies are required by statute to assist AGDC by exercising certain police powers on behalf of AGDC, providing additional evidence that AGDC should qualify as a political subdivision.

Further, AS 31.25.090(a) provides AGDC with access to information of State departments, agencies, and public corporations directly related to the planning, financing, development, acquisition, maintenance, construction, or operation of the Project. All State departments, agencies, and public corporations are required by AS 31.25.090(a) to cooperate with, and provide information, services, and facilities to AGDC, and are generally required to give priority to processing authorization applications and other requests of AGDC. Finally, AS 31.25.090(d) generally requires the Department of Natural Resources to grant AGDC a right-of-way lease under AS 38.35 for the Project's gas pipeline transportation corridor at no appraisal or rental cost.

If AGDC intends to qualify for implied statutory immunity, it will need to address language in AS 31.25 that suggests that AGDC is not a political subdivision of the State. First, AS 31.25.240 states that obligations issued under AS 31.25 are not debts of "the state or of a political subdivision of the state,"[3] implying that AGDC is not a political subdivision. Second, AS 31.25.010 states that AGDC is an instrumentality of the State. As discussed below in the section on instrumentalities, an "instrumentality" for federal tax purposes is by definition something other than a state or a political subdivision of the state. In order to qualify for tax exemption under implied statutory immunity, AGDC will need to prove that it is, in fact, a political subdivision of the State regardless of the language in AS 31.25.010, and is not an instrumentality for federal tax purposes. Specifically, AS 31.25.010 provides that AGDC is

> <u>a public corporation and government instrumentality</u> acting in the best interest of the state for the purposes required by AS 31.25.005, located for administrative purposes in the Department of Commerce, Community and Economic Development, but <u>having a legal and existence independent of and separate from the state</u>.

AS 31.25.010, as would be modified in Sec. 2 of CS for Senate Bill No. 138(FIN) am (emphasis added).

Treasury Regulation § 301.7701-1(a)(3) provides that an entity that is separate from a state or political subdivision "is not always recognized as a separate entity for federal tax purposes."[4] For instance, the Second Circuit held in *Estate of Shamberg* that the Port Authority of New York qualified as a political subdivision, even though the Port Authority's authorizing statutes provided, similar to AS 31.25.010 describing AGDC as a "public corporation and instrumentality," that the Port Authority is

> <u>a body politic and corporate</u>[5] created by a compact made between the States of New York, [**5] Laws N.Y. 1921, c. 154, and New Jersey on April 30, 1921, N.J.S.A. 32:1-1 et seq., and approved by Congress on August 23, 1921, 42 Stat. 174.

*Estate of Shamberg* at 1000 (emphasis added). See also Rev. Rul. 70-562 (finding that a county board of education, described as an instrumentality of the state, qualified as a political subdivision–an acceptable charitable donee under § 170(b)(1)(A)).

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[3] Note that AS 31.25.240 does not say that obligations issued under AS 31.25 are not debts of "the state or of <u>another</u> political subdivision of the state," etc.

[4] Adding, by way of example, that "an organization wholly owned by a State is not recognized as a separate entity for federal tax purposes if it is an integral part of the State."

[5] AGDC is similarly described as a "body corporate and public" in AS 31.25.260(b), dealing with the tax exempt status of its bonds.

In order to clarify that AGDC qualifies for federal tax exemption under implied statutory immunity, the State is advised to consider revising SB 138 and HB 277 to provide that AGDC is a political subdivision, at least for purposes of its eminent domain and police (i.e., regulatory) powers, as well as for tax exemption purposes, and also consider revising language in AS 31.25.240 and AS 31.25.010 suggesting that it is not a political subdivision.

Further, the State is strongly recommended to secure a private letter ruling confirming that AGDC qualifies for tax exemption under implied statutory immunity as a political subdivision of the State.

## II. Whether AGDC is an Integral Part of the State.

If AGDC did not qualify for exemption from federal taxation as a political subdivision of the State, the question would then be whether AGDC qualifies for tax exemption as an integral part of the State or a political subdivision of the State.

Alaska Statutes 31.25.010 provides that AGDC is a:

> public corporation and government instrumentality acting in the best interest of the state for the purposes required by AS 31.25.005, located for administrative purposes in the Department of Commerce, Community, and Economic Development, but having a legal existence independent of and separate from the state.

(Emphasis added.)

This corporate separation raises the issue whether AGDC would be treated as a taxable corporation under federal law, separate from the State of Alaska, which is not subject to federal taxation. A corporation is generally treated as separate from its shareholders for tax purposes. *Moline Props., Inc. v. Comm'r*, 319 U.S. 436, 438-439 (1943).

Whether AGDC qualifies as an integral part of the State turns on whether its corporate status would prevent AGDC from being treated as an integral part of the State for tax purposes.

> Over the years, the IRS has extended the income tax exemption it provides to states and political subdivisions to entities it regards as their "integral parts." See Rev. Rul. 87-2, 1987-1 C.B. 18; *see also* Treas. Reg. § 301.7701-1(a)(3).

IRS Announcement 2011-78, n. 24, 2011-51 I.R.B. 874 (12/19/2011) (emphasis added).

Revenue Ruling 87-2 provides that:

> Income earned by . . . an integral part of a state or political subdivision of a state is generally not taxable in the absence of specific statutory authorization for taxing such income.

(Emphasis added). In other words, even if AGDC failed to have any sovereign power qualifying it as a political subdivision of the State, AGDC could still be exempt from federal income tax if it is an integral part of the State or one of its political subdivisions.

Although AS 31.25.010 states that AGDC is a corporation "having a legal existence independent of and separate from the state," Treas. Reg. § 301.7701-1(a)(3) provides that AGDC's corporate status should not prevent AGDC from being treated as an integral part of the State for tax purposes:

> an organization wholly owned by a State is not recognized as a separate entity for federal tax purposes if it is an integral part of the State.

Treasury Regulation § 301.7701-1(a)(3) indicates that the corporate separation of AGDC can be ignored for tax purposes if AGDC is an integral part of the State. The accompanying regulation, Treas. Reg. §301.7701-2(b)(1) & (6), seems to say that a corporation such as AGDC will, if it is not an integral part of the State, be taxed as a separate corporation.

> For federal tax purposes, the term corporation means–(1) A business entity organized under a Federal or State statute, . . . if the statute describes or refers to the entity as incorporated or as a corporation, body corporate, or body politic; (6) A business entity wholly owned by a State or any political subdivision thereof . . ..

Id.

Unfortunately Treas. Regs. §301.7701–1 & –2 provide no guidance regarding the circumstances that will cause a corporation wholly owned by a state or a political subdivision to be considered an integral part of the state. The Tax Court recently addressed whether a corporation organized under Delaware law was, analogous to Treas. Reg. § 301.7701-1(a)(3), an integral part of an Indian tribe and thus not exempt from federal taxation. *Uniband Inc. v. Comm'r*, 140 TC 13 (2013). The Tax Court in *Uniband* ultimately found that Uniband was organized as a state law business corporation and not under tribal law, that Uniband's constituent documents did not guarantee tribal control of Uniband, that Uniband appeared to have financial autonomy from the tribe, and held that Uniband was not an integral part of the tribe and was subject to federal taxation.

Private letter rulings addressing whether a corporation formed by a state, like AGDC, qualifies for federal tax exemption as an integral part of the state[6] look to whether (a) there is sufficient state control over the entity and (b) whether the state has made a financial commitment to fund the corporation.

The State would control AGDC by controlling its board of directors, consisting of members appointed by, and serving at the pleasure of, the governor and subject to confirmation by the legislature and individuals designated by the governor that are each the head of a principal department of the State. AS 31.25.020.

The State would be making a substantial financial commitment to fund AGDC, and would be controlling its finances. First, as noted immediately above, the State would maintain board control of AGDC. AS 31.25.020. Second, the revised AS 31.25.110 provides that AGDC could only transfer revenues that it has received to an appropriate fund as determined by the commissioner of revenue in consultation with the commissioner of natural resources.

Recent private letter rulings holding that an enterprise or organization qualifies as an integral part of the state for tax purposes use the same analysis and cite substantially the same authorities, regardless whether the enterprise or organization was formed as a corporation. Namely, they each cite[7] Rev. Rul. 87–2 as establishing that income earned by an enterprise that is controlled by the state and is an integral part of the state is not generally subject to federal taxation, and cite *Maryland Savings-Share Insurance Corp. v. United States*, 308 F.Supp. 761, *rev'd on other grounds*, 400 U.S. 4 (1970), for the proposition that, in order to qualify as an integral part of the state, the state must have made a sufficient financial commitment to the enterprise as well as maintained sufficient state control over the enterprise.[8]

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[6] A private letter ruling is only binding on the taxpayer(s) who requested the ruling; they are nonetheless a useful indication of how the IRS would rule on a specific transaction. The only published ruling in this area, Rev. Rul. 87-2, concerned a lawyer trust account fund created by order of the state supreme court that was not an independent entity. Taxpayers are entitled to rely on revenue rulings (such as Rev. Rul. 87-2), which are an official interpretations of the tax law on specific transactions published by the national office of the Internal Revenue Service.

[7] Of the private letter rulings discussed immediately below, PLR 200403026 and 200427016 also cite Treas. Reg § 301.7701-1(a) as providing that an organization wholly owned by a state is not recognized as a separate entity for federal tax purposes if it is an integral part of the state.

[8] Each of the private letter rulings listed immediately below also distinguishes *Michigan v. United States*, 802 F. Supp. 120, 127 (W.D. Mich. 1992), rev'd, 40 F. 3d 817 (6th Cir. 1994), which the Service believes is a flawed opinion that misapplied Rev. Rul. 57–128. (Professor Aprill also criticizes the *Michigan* opinion, concluding that "[i]n treating the trust as exempt, the majority confused and misapplied the tests for political subdivision, instrumentality, and integral part." *23 Iowa J. Corp. L. at 825.)* While the *Michigan*

For instance, PLR 200403026 held that a hospital was as an integral part of a city for federal income tax purposes. The ruling found that the city had substantial control over the hospital (all of the members of the board were appointed by the mayor and subject to approval of the city commissioners; and the hospital's annual budget and audit were reviewed annually by the city commission). The ruling found that the city had made a substantial financial commitment to the hospital (the city contributed the hospital facilities and the land on which the facilities are located; and the city contributed cash and bond proceeds, including the proceeds from general obligation bonds, for the acquisition of additional land and the construction and renovation of the hospital facilities).

PLR 200136011 held that an authority, created by state statute to encourage commercial space flight from the state by promoting research and participating in the development of a commercial flight center, was as an integral part of the state for federal income tax purposes. The ruling found that the state had substantial control over the authority (of the authority's twelve directors, four were public officials and eight were appointed by the governor, subject to approval by both houses of the state legislature; the authority is required by statute to submit a detailed initial plan for the use of general funds appropriated for the authority to the governor and the state legislature, and the authority is required to submit an annual report and financial statement to the governor and the state legislature). The ruling also found that the state had made a substantial financial commitment to the authority by contributing moneys to the authority.

PLR 200427016 held that a non-profit public corporation, formed by the state legislature to operate insurance plans that function exclusively as residual market mechanisms to provide essential property insurance for residential and commercial property, was as an integral part of the state for federal income tax purposes. The ruling found that the state had substantial control over the corporation (the directors include public officials and their designees, and members appointed by the commissioner or governor, all senior management serve at the commissioner's pleasure, the corporation must file regular financial reports and its plan of operation must be approved by the department, the corporation's rates are specified by legislation, and all bonds and other indebtedness of the corporation must be approved by a state commissioner). The ruling also found that the state had made a substantial financial commitment to the corporation (by enacting legislation authorizing the corporation to collect the premium tax and to retain the proceeds of the premium tax to augment the corporation's resources).

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analysis was recently adopted by the Tax Court in *Uniband Inc. v. Comm'r* (holding that a corporation organized under Delaware law was not an integral part of an Indian tribe), the Service's long-standing refusal to acquiesce in the *Michigan* opinion means that the Service likely will continue to issue private letter rulings that conform to its current ruling position based on Rev. Rul. 87–2 and *Maryland Savings-Share*, namely that State control and financial commitment are necessary to establish that an enterprise is an integral part of the State.

PLR 200827004 concerned whether an amendment to state law requiring additional assessments from insurers participating in the state insurance fund would alter the previous private letter ruling finding that the insurance fund was an integral part of the state for tax purposes. The ruling found that the state maintained board control over the fund as it had before, and that the amendment had not materially altered the state's financial commitment to the fund, and held that the fund maintained its status as an integral part of the state.

Reliance on AGDC being treated as an integral part of the State is problematic, however, as the IRS has not been consistent over the years in their rulings on whether a corporation formed under a state statute will be treated as an integral part of the state or its subdivisions. Enterprises that would seem to qualify as an integral part of a state or its political subdivisions sometimes receive rulings that they qualify for tax exemption under § 115(1), under which the IRS currently will only issue a favorable ruling based upon a showing of no private benefit.[9]

In sum, AGDC's qualification for tax exemption as an integral part of the State or its political subdivisions cannot be assured without a favorable private letter ruling.

## III. Whether AGDC Qualifies as a Section 115 Entity.

If AGDC were not to qualify for tax exemption either under implied statutory immunity as a political subdivision of the State, or as an integral part of the State or its political subdivisions, the next question is whether AGDC qualifies for tax exemption under § 115.

Code § 115(1) provides that the income of AGDC would be excluded from federal taxation if it is derived from the exercise of any essential government function and accrues to the State or any of its political subdivisions.

In private letter rulings, the IRS not only examines the § 115(1) criteria of whether income is derived from the exercise of an essential government function and accrues to the state or its subdivisions but also considers whether private parties would benefit from the entity. The most recent published ruling regarding tax exemption under § 115 is Rev. Rul. 90–74. Revenue Ruling 90–74 held that the income of a nonprofit organization formed by county governments of the state to pool the casualty risks of the member-counties was excluded from income under §115(1), based upon findings that pooling casualty risks instead of purchasing commercial insurance constituted the exercise of an essential government function, that distribution of the assets of the organization upon dissolution to

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[9] E.g., PLR 8934052 (arts commission exempt under § 115, and not as integral part, because a state statute makes it a separate body "corporate and politic").

the member-counties satisfied accrual of income for purposes of § 115(1), and that private interests did not, "except for incidental benefits to employees of the participating state and political subdivisions, participate in or benefit from the organization."

## Essential Government Function

For ruling purposes, the IRS tends to regard anything that makes or saves money for a political subdivision as an essential government function:[10]

> it may be assumed that Congress did not desire in any way to restrict a State's participation in enterprises that might be useful in carrying out those projects desirable from the standpoint of the State government which, on a broad consideration of the question, may be the function of the sovereign to conduct.

Rev. Rul. 77–261. Revenue Ruling 77–261 held that a state investment fund, for the temporary investment of cash balances of the state and its political subdivisions, "constitutes the exercise of an essential governmental function for purposes of section 115(1) of the Code."

A recent private letter ruling with many similarities to the Project, PLR 200524015, found that a nonprofit corporation formed by political subdivisions of the state, consisting of natural gas and electric joint action agencies and distribution systems, qualified for exemption under § 115(1). The ruling specifically found that acquiring and financing long-term natural gas supplies, acquiring, constructing, owning, managing, operating and financing natural gas pipelines, liquefied natural gas facilities, storage and related facilities and equipment, and contracting with joint action agencies and public gas or power systems to provide them with natural gas supplies all constituted an essential governmental purpose within the meaning of § 115(1).

## Accrual

In order to obtain a private letter ruling under § 115(1), an organization must show that it has satisfied the accrual test by including in its articles of organization a provision limiting distribution upon dissolution of all of AGDC's assets

[10] Aprill at 816. Note that there is very little contemporary authority that taxpayers are entitled to rely on, beyond the revenues rulings cited herein, for what constitutes "an essential governmental function" for purposes of §115(1). Case law is less than clear– the United States Supreme Court has concluded that it is essentially impossible to define what an essential governmental function is. The Supreme Court in *Garcia v. San Antonio Metropolitan Transit Authority*, 469 U.S. 528 (1985) concluded that "'[t]here is not, and there cannot be, any unchanging line of demarcation between essential and non-essential governmental functions.'"

> to one or more States, political subdivision(s) thereof, the District of Columbia, or to other organizations whose income is excluded from gross income under section 115(1).

Rev. Proc. 2003-12.

AGDC is a corporation specifically authorized by statute, AS 31.25. Alaska Statutes 31.25.010 provides that "[u]pon termination of [AGDC], its rights and property pass to the state," which appears to comply with the ruling requirements of Rev. Proc. 2003–12.

Note that the courts have been less generous in their interpretation of what is required to satisfy the accrual requirement for tax exemption under § 115(1) than the ruling position of Rev. Proc. 2003-12,[11] which only requires disbursement of assets upon dissolution to the state or its political subdivisions to satisfy the accrual requirement. For instance, *City of Bethel v. U.S.*, 594 F.2d 1301 (9th Cir. 1979), *cert. denied*, 444 U.S. 980 (1979)[12] held that the mere accrual of income to a corporation owned by the governmental entity is not considered accrual to the governmental entity. The fact that the assets will revert to the state upon the corporation's dissolution, that the government was the sole owner of the corporation, or even that the state may request payment of profits at any time, did not qualify as direct accrual.

<u>No Private Benefit</u>

The IRS ruling position, that an entity cannot qualify for tax exemption under § 115 if it serves a private interest that is not incidental to the public interest, has no statutory basis. This requirement was apparently first asserted in PLR 8825027, the ruling that denied the Michigan Education Trust exemption under § 115 (a ruling that was effectively reversed by the Sixth Circuit in *Michigan v. United States*). Id. at n. 4.

> To qualify under section 115, it must be established that the income does not serve private interests such as designated individuals, shareholders of organizations, or persons controlled, directly or indirectly, by such private interest. Thus, even if the income serves a public interest, the requirements of section 115 are not satisfied if the income also serves a private interest that is not incidental to the public interest. The basic principle underlying section 115 is that property (including any income thereon) must be devoted

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[11] Rev. Proc. 2003-12 only addresses ruling requirements for a § 501(c)(3) organization that requests a ruling that it is also exempt under § 115(1), but likely reflects the Service's ruling position for an entity affiliated with a state that requests a ruling under § 115(1).

[12] The *City of Bethel* is a Ninth Circuit case, and is binding authority for AGDC.

> to purposes which are considered beneficial to the community in general, rather than particular individuals.

PLR 8825027.

IRS rulings from the 1990s regarding state-sponsored disaster funds designed to deal with private insurance companies pulling out of the market for insuring certain forms of risk illustrate the risk that AGCD's involvement in the Project might be considered by the IRS to benefit private parties. For instance, the Florida and California private letter rulings, respectively PLR 9507037 and PLR 9622019, both found that the respective state disaster funds qualified for tax exemption as integral parts of their respective states, and concluded that, because the fund was an integral part, § 115 did not apply to the fund. Technical Advice Memorandum 94347001 reviewed another state's disaster fund and found that, besides failing to qualify as an integral part of the state or as a political subdivision of the state, the disaster fund also did not qualify for exemption under §115.

In declining exemption under §115, TAM 94347001 noted that "the sole purpose of [the fund] is to provide commercial–type insurance for private entrepreneurs," and specifically contrasted the fund with the risk pool at issue in Rev. Rul. 90–74, which pooled the risk exposure of political subdivisions of the state, and where private interests did not benefit more than incidentally. The disaster funds in Florida and California that received favorable rulings in PLR 9507037 and PLR 9622019 likely would not have qualified for exemption under §115 under the same analysis, as those disaster funds primarily benefited the private individuals seeking insurance coverage that they had not been able to obtain from the private insurance market. See Aprill at 828-830.[13]

AGDC's only owner will be the State or one of the State's political subdivisions. All distributions of AGDC are required by AS 31.25.110 to be distributed to an appropriate fund as determined by the commissioner of revenue in consultation with the commissioner of natural resources. While AS 31.25.110 is not clear on this point, the "appropriate fund" restriction seems intended to bar distributions from AGDC to anything other than a political subdivision or instrumentality of the State. The lack of clarity in what is an "appropriate fund" conceivably could be interpreted by the IRS as allowing the possibility of a private benefit from the fund.[14]

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[13] Also discussing the considerable congressional pressure that was applied by the delegation of California to ensure that California received and retained a favorable private letter ruling.

[14] It is perhaps conceivable that the IRS could also find that the State's investment in, and ownership of, a minority interest in the Project, while providing additional royalty and tax revenue for the State and for the energy needs of the people of Alaska, could more than incidentally benefit the other investors in the Project.

It will be essential for the State to secure a favorable private letter ruling recognizing federal tax exemption under § 115 if AGDC intends to rely on exemption under that provision.

## IV. Instrumentalities.

Alaska Statutes 31.25.010 states that AGDC is "a public corporation and government instrumentality . . ." (emphasis added). For tax purposes, an instrumentality is, by definition, an entity that is not a state or a political subdivision of a state. §§ 3121(b)(7)(F), 3306(c)(7) and 414(d); Rev. Rul. 57–128.

With the exception of certain corporations organized under an act of Congress as instrumentalities of the United States, status as an instrumentality does not indicate whether a corporation such as AGDC is exempt from federal taxation. Code § 501(c)(1) and Rev. Rul. 77–271. Revenue Ruling 77–261 concerned an investment fund established by a state treasurer that was "specifically designated as an instrumentality" of the state. After finding that the investment of funds was the exercise of an essential governmental function and after finding that the fund's income accrued to the state and the participating political subdivisions of the state, Rev. Rul. 77–271 held that income of the investment fund was exempt from federal income tax under §115(1). [15]

Designation as an instrumentality has significance for social security tax, federal unemployment tax and eligibility for governmental pension plans. §§ 3121(b)(7)(F), 3306(c)(7) and 414(d). The IRS analyzes whether an organization qualifies as an instrumentality for such purposes under the criteria set forth in Rev. Rul 57-128:

> (1) whether it is used for a governmental purpose and performs a governmental function; (2) whether performance of its function is on behalf of one or more states or political subdivisions; (3) whether there are any private interests involved, or whether the states or political subdivisions involved have the powers and interests of an owner; (4) whether control and supervision of the organization is vested in public authority or authorities; (5) if express or implied statutory or other authority is necessary for the creation and/or use of such an instrumentality, and whether such authority exists; and (6) the degree of financial autonomy and the source of its operating expenses.

If the IRS concluded that AGDC was an instrumentality, and not a political subdivision or an integral part of the State, it would examine whether AGDC qualified for

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[15] In other words, Rev. Rul. 77 – 261 held that the investment fund qualified for tax exemption under § 115(1); that holding was not based on the fund's status as an instrumentality of the state.

federal tax exemption under either § 115(1) (discussed above) or § 501(c), primarily § 501(c)(3) (discussed below). Aprill at 821.

If AGDC is considered an instrumentality of the State, it will be essential for the State to secure a favorable private letter ruling recognizing federal tax exemption under § 115 if AGDC does not qualify for exemption as a political subdivision of the State or as an integral part of the State.

## V. § 501(c)(3) Organizations.

AGDC, as a " public corporation and instrumentality" of the State could qualify for exemption under §501(c)(3) if it were a "clear counterpart" of a charitable, educational, religious or like organization. Rev. Rul. 60–384; see also Rev. Rul. 55–319. There is at least an issue whether the IRS would consider AGDC, investing in a liquefied natural gas Project, to be a "clear counterpart" of a charitable organization.

Further, if AGDC is an integral part of the State, which it would seem to be if it does not qualify a political subdivision, it would not qualify for exemption under §501(c)(3). Revenue Ruling 60-384 ruled that because a state's purposes include those not exclusively described in § 501(c)(3), an organization that is an integral part of the state cannot meet the requirements for exemption under § 501(c)(3.

Finally, if AGDC's powers exceed the scope of those allowed by § 501(c)(3), AGDC would not qualify for exemption under § 501(c)(3). Rev. Rul. 60-384. AGDC's regulatory powers, discussed above, appear to disqualify AGDC as a § 501(c)(3) organization. Id. In Rev. Rul. 74–14, a public housing authority was denied exemption under § 501(c)(3), even though its purpose was to provide safe housing accommodations for low income families, because the state statute incorporating the authority gave it the power to conduct examinations and investigations for the purpose of collecting information and making it available to appropriate agencies for use in furthering and enforcing local ordinances regarding planning, building, and zoning matters. Revenue Ruling 74–14 concluded this power to conduct examinations and investigations was a regulatory power that was inconsistent with exemption under § 501(c)(3).

For reasons such as those set forth above, § 501(c)(3) seems the least likely ground for AGDC to qualify for federal tax exemption.

## VI. Conclusion.

The State is strongly recommended to secure a private letter ruling confirming that AGDC qualifies for tax exemption at the earliest opportunity, as AGDC's involvement in the Project will require substantial State investment. If SB 138 and HB 277 are enacted into law, the ruling request should be made shortly thereafter.

In order to facilitate securing a favorable ruling, the Committee is also advised to incorporate the changes discussed in principle at page 8 of this letter into SB 138 and HB 277, to better establish that AGDC's qualifies for implied statutory immunity as a political subdivision of the State.

Notice Regarding Tax Advice

We hope that this letter helps explain the federal tax exemption issues raised by the Project and the related pending legislation. We would be happy to expand upon our analysis should the Committee or the Legislature so desire or to address any particular questions that the Committee or the Legislature may have.

This letter has been prepared solely for use by the State, the Legislative Budget & Audit Committee, and the Alaska state legislature. Any tax advice contained in this letter was not intended or written to be used, and cannot be used, for the purpose of (i) avoiding tax-related penalties under the Internal Revenue Code, or (ii) promoting, marketing, or recommending to another party any transaction or matter addressed herein.

The advice in this letter is not binding on the Internal Revenue Service, any court, or any other person or entity. The Internal Revenue Code has been subject to substantial and frequent revisions in recent years. We cannot assure that forthcoming IRS interpretations, administrative pronouncements, or court decisions will not adversely affect the tax advice given in this letter.

Realization of federal tax exemption is subject to the risk that the Internal Revenue Service may challenge tax treatment and that a court may sustain that challenge. Because taxpayers carry part of the burden of proof required to support the tax treatment of a transaction, the advice expressed as to the likelihood of realization of federal tax exemption assumes that you will undertake the effort and expense to request an appropriate private letter ruling and present fully the State's case in support of any matter that the Service challenges.

Sincerely,

MANLEY & BRAUTIGAM, P.C.

By: 
Charles F. Schuetze

ALASKA GASLINE DEVELOPMENT CORP.
GAS FOR ALASKANS

The Honorable Kevin Meyer
Senate President
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The Honorable Cathy Giessel
Chair, Senate Resources Committee
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August 11, 2016

Dear Senator Meyer and Senator Giessel:

This is in response to your letter dated July 15, 2016, where you requested information to assist the Legislature's evaluation of the Alaska Gasline Development Corporation (AGDC) draft concept proposal for Alaska natural gas development. Specifically, you requested an explanation (in broad terms and to the extent permissible under applicable confidentiality obligations) of the Pre-FEED Joint Venture Agreement (JVA) and other Alaska LNG Project commercial agreements as they relate to each participant's election to continue the Alaska LNG Project beyond the Pre-FEED phase. Your letter also requested that AGDC work with the JVA Parties to determine what aspects of these agreements might be made public.

AGDC appreciates your sensitivity to the confidential nature of the commercial agreements associated with the Alaska LNG Project, including the JVA. While the terms of the JVA and other project-related agreements are confidential, AGDC consulted with BP, ConocoPhillips, and ExxonMobil and provides the summary below, which may be shared publicly.

The Pre-FEED JVA. The parties to the JVA are AGDC, BP Alaska LNG LLC (BPALL), ConocoPhillips Alaska LNG Company (CALC), and ExxonMobil Alaska LNG LLC (EMALL). TransCanada Alaska Midstream LP was initially a JVA Party, but its interest was acquired by AGDC in November 2015. In broad terms, the JVA provides the terms and conditions under which the JVA parties execute work, share costs for the work, and achieve certain rights to the work product and any other property interests that arose from the conduct of the work.

It is important to note that the JVA applies to Pre-FEED activities only and focuses on the development of the technical work required for the project; it does not apply to any Alaska LNG Project activities after Pre-FEED. Following the completion of the Pre-FEED work and deliverables, expected in September of this year, each JVA Party will review the deliverables and then will indicate its interest in preparing for FEED. If two or more JVA Parties indicate an interest in preparing for FEED, those Parties would negotiate with the aim of concluding an agreement for the next stage (i.e., a FEED agreement). If a FEED agreement is executed prior to expiration of the remaining term of the JVA (the JVA term runs through June 30, 2017 unless terminated sooner), the conduct of the operations would be transitioned to FEED work under that FEED agreement. If only one JVA Party indicates an interest in preparing for FEED, the JVA terminates.

Specifically addressing the request concerning a party not continuing beyond Pre-FEED, all parties, whether continuing or not, have similar rights and obligations to use the information and deliverables produced under and subject to the terms of the JVA, including confidentiality.

However, notwithstanding the terms of the JVA, ExxonMobil, BP, and ConocoPhillips have each indicated in testimony that if AGDC is the only party that indicates interest in preparing for FEED in 2017, they are willing to work with AGDC to negotiate a transition to a State-led Alaska LNG project. Furthermore, each is willing to individually make its natural gas available to a State-led Alaska LNG project on bi-lateral, mutually agreed commercially reasonable terms.

The Alaska LNG Project LLC (ALPL) Agreement. Another commercial matter of importance is for AGDC to demonstrate access to the assets held by the ALPL. The ALPL Agreement is among BPALL, CALC, and EMALL as its Members (shareholders). Among other assets, ALPL holds title to land in Nikiski, where the Alaska LNG plant and marine terminal would be sited, and possesses the U.S. Department of Energy LNG export authorization. The ALPL has thus far been funded solely by the three Members, separate and apart from the JVA. AGDC is not a party to the ALPL Agreement as it was established in the Concept Select phase, before Senate Bill 138 and AGDC's participation in the JVA. However AGDC intends to negotiate to achieve access to the ALPL assets. These negotiations would be an important part of a transition to a State-led Alaska LNG project.

The FERC NEPA Pre-Filing Terms of Reference (TOR) Agreement. The four JVA Parties along with the Department of Natural Resources (DNR) and Department of Revenue (DOR) are parties to the TOR Agreement. The purpose of this agreement is to govern the terms of the FERC NEPA pre-file process among the parties (i.e., the approval of the content and filing of FERC draft Resource Reports). While EMALL, under the JVA, is charged with preparing the draft Resource Reports, the TOR parties decide on the final content and the filing of the draft Resource Reports with the FERC. To date, draft Resource Reports 1 through 10 (in excess of 34,000 pages) have been agreed among the TOR parties and filed with the FERC and are open to the public for review on the FERC website. Resource Reports 11 and 13 are under development. Given the confidential nature, FERC would not post these two Resource Reports on their website. The TOR Agreement only covers FERC related matters during the NEPA pre-file process and expires when the JVA expires.

I hope that you find this summary helpful. Please let me know if you have any additional questions.

Regards,

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ALASKA GASLINE DEVELOPMENT CORP.

# PRESIDENT'S REPORT

***BOARD OF DIRECTORS MEETING***

**AUGUST 18, 2016**

www.agdc.us

# Key Messages

- The Alaska LNG project continues to make good technical progress. Pre-FEED work is over 90% complete and Pre-FEED deliverables are anticipated by mid-September.
- The Parties are working together to consider commercial options to improve the project's ability to compete in the global LNG market.
- As part of the effort to improve the project's competiveness, the Parties are working collaboratively to transition the project to State leadership. They are also pursuing alternative commercial structure options and concepts that have been successfully used in global LNG projects to reduce the Cost of Supply of the project. The goal is to have a seamless continuation of the project and maintain project momentum.
- Planning for the transition to an AGDC-led Alaska LNG project is underway with the target for commencement by the end of October with completion by the end of the year. Once transitioned, the Alaska Gasline Development Corporation will be responsible for managing the project going forward including: a) applying for regulatory approval, b) securing the commercial commitments from gas sellers, shippers, and buyers necessary to acquire the equity and debt financing that will be required to complete the project, and c) preparing to start FEED.

# Additional AGDC Messages

ALASKA GASLINE DEVELOPMENT CORP.

- AGDC has approved funding through FY2017. A decision on supplemental FY2017 funding is pending. As part of the State's budgetary process, AGDC will provide a budget request to the Alaska Legislature for FY2018.
- AGDC will augment its current technical, commercial, and project management expertise as necessary, consistent with project progress and funding.
- AGDC plans to ensure the Alaska LNG project builds upon the tremendous expertise and accomplishments already invested into the project.
- The AGDC greatly appreciates the professional and cooperative way the parties have advanced the project to this stage and looks forward to working closely with them during the next stage of the project.

# Refining the "Stage Gates"

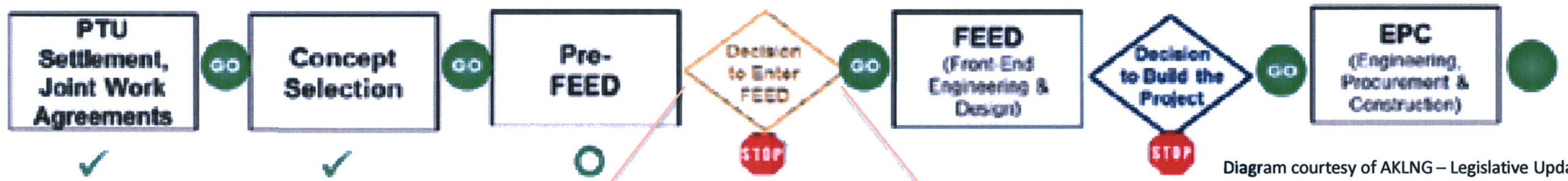
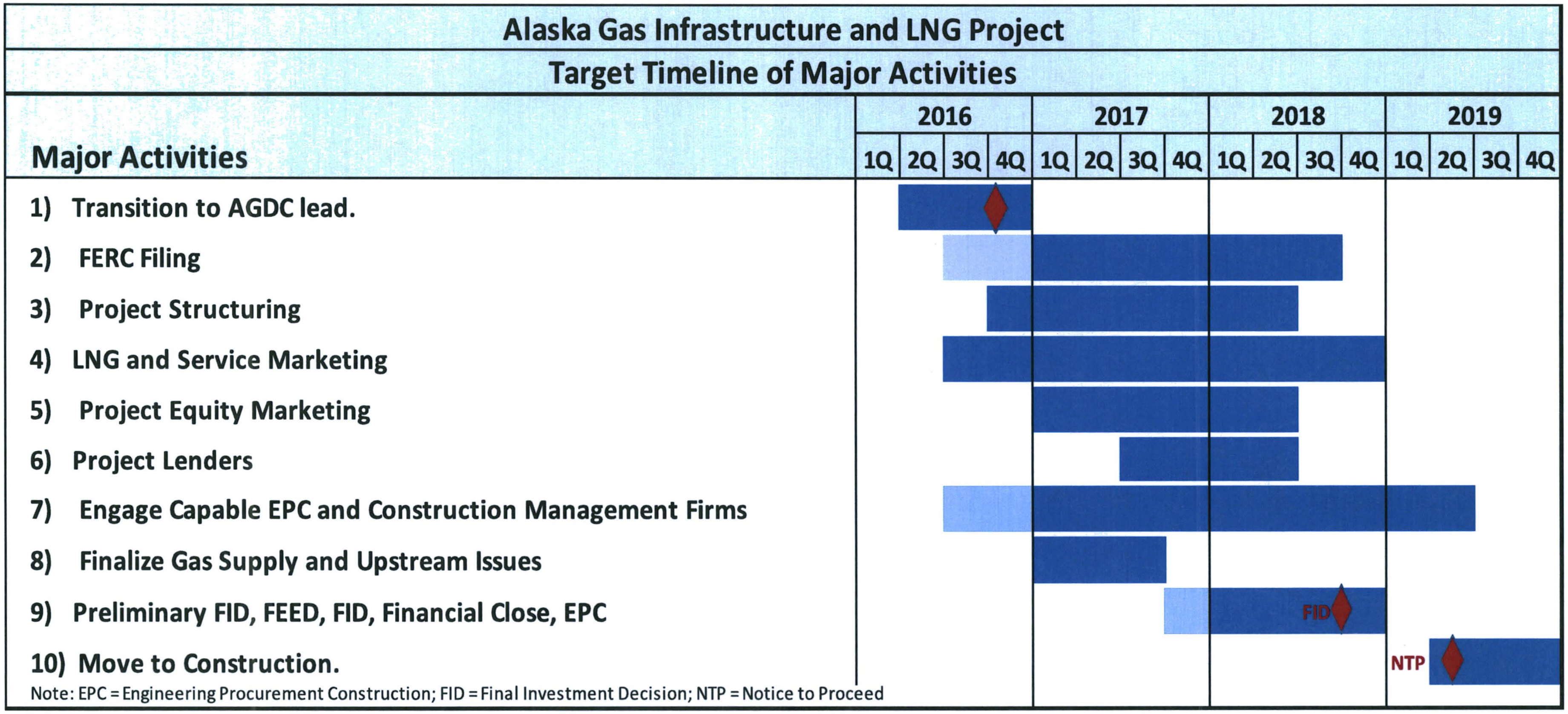



Diagram courtesy of AKLNG – Legislative Update 29Jun2016

## New elements in the "Decision to Enter FEED":

- Have we structured the project for tax and other financial efficiencies?
- Have we secured customers sufficient for financing?
- Have we identified and secured parties interested in equity investment in the infrastructure project?
- Have we identified and secured lenders for non-recourse project debt finance?
- Have we secured large EPC companies competent to manage the construction of the project and shoulder a significant part of the construction related risks?

# Major Activity Timeline



# Other Upcoming Activities

ALASKA GASLINE DEVELOPMENT CORP.

- **Preparing for Legislative Hearing on August 24-25**

- **Preparing for International Marketing Opportunities**
  - ✓ Identify G to G opportunities
  - ✓ Strategic planning for sales and marketing

- **Preparing FY 2018 Budget**

THE STATE
of ALASKA
GOVERNOR BILL WALKER

Department of Law

CIVIL DIVISION
1031 West 4th Avenue, Suite 200
Anchorage, Alaska 99501
Main: 907-269-5100
Fax: 907-276-3697

July 13, 2016

Honorable Cathy Giessel
State Capitol
120 4th Street, Room 427
Juneau, Alaska 99801-1182

Re: *Alaska Gasline Development Corporation*
AGO No. AN2014102400

Dear Senator Giessel:

Jane Conway, your Chief of Staff, has passed to us your inquiry about whether or not the Alaska Gasline Development Corporation ("AGDC") has the authority under SB 138 to change the model for the AKLNG project.

We understand that your inquiry stems from AGDC's recent proposal to restructure the AKLNG project as it proceeds beyond the current pre-front end engineering and design stage ("pre-FEED"). AGDC's proposed restructuring would have the State take the lead on the effort to monetize North Slope gas. At present, AGDC's proposed restructuring is still being worked out. AGDC's President Keith Meyer has discussed the possibility of AGDC, or an affiliate of it, owning the infrastructure for the project, or sharing ownership of the project infrastructure with one or more of the gas producers (ExxonMobil, BP and ConocoPhillips). Ownership could also be shared with outside investors. The cost of constructing the project would be funded through third-party project financing that may or may not include any significant equity contribution from the project infrastructure owner(s). The producers could be shippers of gas in the system, or they may only be sellers of gas at the wellhead, or they could do both. The project company would toll gas through the system for the shippers, or it or an affiliate also might be a shipper itself by purchasing gas at the wellhead, transmitting it through the system and selling it to third party purchasers at the marine terminal. The exact nature of the proposed restructuring and all the details concerning it are in flux and are the subject of on-going discussions between AGDC and the producers.

As a statutory creation, AGDC can perform only those functions and exercise only those powers as the statutes give it. AGDC's statutory authority is set out in chapter 31.25 of the Alaska Statutes, as mostly recently amended in 2014 by SB 138. The statutes give AGDC significant powers in pursuing "an Alaska liquefied natural gas project," which is defined in the statutes as including "collectively, the Prudhoe Bay unit gas transmission line, the Point Thompson unit gas transmission line, a gas pipeline, the gas treatment plant, a liquefied natural gas plant, and a marine terminal."[1] Our understanding is that the restructured project AGDC is proposing involves all of these specific components.

AGDC's governing statutes do not dictate that any particular structure be used in developing an Alaska liquefied natural gas project. Instead, the statutes give AGDC considerable leeway in proceeding with the project. AGDC is specifically authorized to "acquire an ownership or participation interest in an Alaska liquefied natural gas project, . . . or an entity or joint venture that has an ownership interest in or is engaged in the planning, financing, acquisition, maintenance, construction, and operation of an Alaska liquefied natural gas project."[2] The statutes do not either prohibit or require that AGDC's ownership or participation interest in a project company be 100% or shared with others or divided up in any particular way.[3] Thus, we see AGDC's restructuring proposal, as Mr. Meyer has preliminarily outlined it, as fitting within this statutory authorization.

We recognize that there is one provision in AS 31.25 that refers to joint ownership of the Alaska liquefied natural gas project. AS 31.25.080(a)(1) states that AGDC "may enter into agreements with other persons for joint ownership, joint operation, or both of . . . an Alaska liquefied natural gas project." Because this provision is phrased in permissive terms ("may"), and because AGDC's governing statutes must be construed so as to give effect to all of them, we do not interpret this one provision as requiring that AGDC must only develop the project through a joint ownership structure. Rather, joint

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1 AS 31.25.390(1).

2 AS 31.25.080(a)(23).

3 The authority of this provision is further broadened by AGDC's general powers to "make and execute agreements, contracts, and other instruments necessary or convenient in the exercise of the powers and functions of the corporation" (AS 31.25.080(a)(11)) and to "do all acts and things necessary, convenient, or desirable to carry out the powers expressly granted or necessarily implied in this chapter" (AS 31.25.080(a)(20)).

ownership is among the options that AGDC may utilize in the project but it is not the exclusive way for AGDC to proceed.

We also note that Mr. Meyer's description of the project going forward includes the possibility of there being joint ownership of the project infrastructure, either between AGDC and all or some of the producers or with outside investors. The project as restructured therefore may include a joint ownership aspect, which is in line with the options the statutes authorize.

The history of SB 138 supports our conclusion that AGDC is not bound to follow any one particular structure for the project. At the time SB 138 was adopted, the State, AGDC, TransCanada, and the producers had entered into the Heads of Agreement, dated January 14, 2014 (the "HOA"). The HOA specified that the multi-party structure it envisioned was applicable to the pre-FEED stage of the project. At the completion of pre-FEED, the HOA specified that the parties were to decide whether and how to proceed to the next stage, FEED. The decision on the next stage was up to each party "in its sole discretion."[4] SB 138 was enacted with the HOA in mind. As such, SB 138 did not lock AGDC into any one project structure because the parties themselves had reached no understanding on the project structure for the entirety of the potential life of the project.

After the passage of SB 138, the HOA was superseded by the Alaska LNG Project Pre-FEED Joint Venture Agreement (the "JVA"). The JVA itself is a confidential document. However, the producers and others have publicly disclosed that the JVA, like the HOA, covers only the pre-FEED stage of the project. No binding agreement is in place for the FEED stage. For the project to proceed to FEED, the parties wanting to go forward have to reach a new agreement on how they will do so. AGDC's restructuring proposal is consistent with the JVA in that it is a proposal for moving the project forward to the next stage and beyond.

In short, we conclude AGDC is acting within its statutory authority in proposing a restructuring of the Alaska liquefied natural gas project.

Please understand that we are not saying AGDC has a free hand to proceed in any manner it chooses. AGDC will need to continue to review the structure to be sure proposals as they evolve stay within the bounds established by the legislature.

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4 HOA § 4.3.

We trust this adequately answers your inquiry. If you should require further information or assistance, please let us know.

Sincerely,

JAMES E. CANTOR
ACTING ATTORNEY GENERAL

By: Jerome H. Juday

Jerome H. Juday
Senior Assistant Attorney General

JHJ/aec

cc: Mr. Keith Meyer

ALASKA GASLINE DEVELOPMENT CORP.
GAS FOR ALASKANS

August 1, 2016

Mr. Blake Johnson
5220 Solar Ave
Kenai, AK 99611
blakealaska@gmail.com

**Re: Alaska LNG Kenai Spur Highway Relocation**

Dear Mr. Johnson:

Thank you for inquiring at the Alaska Gasline Development Corporation (AGDC) regarding your concerns over the Kenai Spur Highway Relocation.

We appreciate your commitment to the communication process and transparent approach. Enclosed are two letters regarding the Kenai Spur Highway decision; one from the Alaska LNG project office and another from the Department of Transportation. We hope these letters will provide you the information and understanding that this decision is significant to all the parties involved.

In addition to the enclosures, the Alaska Gasline Development Corporation is personally committed to an expedient and accurate due diligence process. We, like you, want to progress this project for Alaskans as quickly as possible. AGDC is charged with advancing and securing a long-term energy supply for Alaska. We take this directive very seriously and are dedicated toward rapidly advancing the development and construction of an integrated natural gas project. As an independent, public corporation of the State of Alaska, we honor the regulatory approval and legislative process, and we encourage you to continue to be engaged during this process.

We welcome your support of the Alaska LNG project and appreciate the opportunity to discuss this project with you. Please feel free to contact us if you would like to discuss this topic further.

Sincerely,

Keith M. Meyer

cc: Alaska LNG
Department of Transportation
Mayor Mike Navarre
Honorable Peter Micciche

Honorable Kurt Olson
Honorable Mike Chenault

Enclosures: Document No.: USAL-PE-SALTR-OO-000007-000
Department of Transportation

Alaska ™

**Alaska LNG Project**
3201 C Street, Suite 506
Anchorage, Alaska 99503

Document No.: USAL-PE-SALTR-00-000007-000

July 27, 2016

Mike Navarre, Mayor
Kenai Peninsula Borough
144 N. Binkley St.
Soldotna, Alaska 99669

Honorable Kurt Olson
Alaska House of Representatives
145 Main St. Loop, Suite 221
Kenai, Alaska 99611

Honorable Peter Micciche
Alaska State Senate
45 Main Street Loop, Suite 217
Kenai, Alaska, 99611

Honorable Mike Chenault
Alaska House of Representatives
145 Main St. Loop, Suite 223
Kenai, Alaska 99611

Re: Alaska LNG Kenai Spur Highway Relocation

Dear Sirs:

Thank you for your efforts in maintaining open and direct communication with the Alaska LNG Project team. We understand the Kenai Spur Highway relocation effort related to the Alaska LNG Project is an important topic in your area and cause for many questions and speculation.

The Alaska LNG Project is committed to providing you with the most current information on this effort. Herein we have assembled a few important points outlining our work this year.

Kenai Spur Highway Relocation

- When construction of the Alaska LNG facility moves forward, some changes to the roads in Nikiski would be required.
- Planning work for the relocation of the Kenai Spur Highway continues. For the remainder of 2016, work includes primarily definition of the regulatory path forward, gathering additional information on route options, and advancing engineering on those options. This effort will take us to the end of the pre-FEED stage of development (the end of 2016).
- There is not a plan to identify a preferred or recommended option to advance design in 2016.
- There is not a plan to reach out to landowners for the potential purchase of land related to the road relocation until a preferred option is recommended.
- Should new developments related to this effort arise in 2016, we will be sure to share them with you, the local community, the Alaska Department of Transportation and Public Facilities and the Kenai Peninsula Borough.
- Alaska LNG is committed to engaging with the community and encourages ongoing dialogue. The community can contact our local representative: Josselyn O'Connor at 907-360-6735 or Josselyn.oconnor@exxonmobil.com if you have questions or require additional information.

As you are aware, the Alaska LNG Project faces headwinds: regulatory approvals; challenging economic environment; complex fiscal and commercial agreements to be developed; and the need to keep the total cost of supply down to compete in global LNG markets.

As part of the Alaska LNG Project team, our focus is on completing our technical work and preparation of the resource reports in 2016. Our job is to provide our owners with the most comprehensive and credible data on which to base their decisions moving forward. We maintain focus and momentum in achieving these objectives.

We greatly appreciate your ongoing support and work with the project. Please do not hesitate to contact us if you would like to discuss this topic further.

Sincerely,

P E Brinkmann

Philip Brinkmann

Cell: 907-202-3171
Alaska LNG Licensing Manager
ExxonMobil Development Company
For and on Behalf of ExxonMobil Alaska LNG LLC

THE STATE of ALASKA
GOVERNOR BILL WALKER

**Department of Transportation and Public Facilities**

CENTRAL REGION
Regional Director's Office

4111 Aviation Avenue
Anchorage, Alaska 99502
Main: 907.269.0770
Fax: 907.248.1573
TDD: 907.269.0473
dot.state.ak.us

July 6, 2016

blakealaska@gmail.com

Dear Mr. Johnson:

Thank you for contacting the Alaska Department of Transportation & Public Facilities (DOT&PF) and your patience while I took time to research the issue of the LNG line route selection.

Your concern is understood and appreciated. The Department recognizes that the uncertainty with this project is particularly unsettling for property owners who may be affected. Unfortunately, the DOT&PF is not the agency making the decision regarding the route selection.

The DOT&PF will be responsible for constructing the road after the route is selected. However, because DOT&PF is not leading this project, we do not have the authority over the project timeline, route selection, or property acquisitions. DOT&PF's role at this time is to provide review and input to the Liquid Natural Gas (LNG) team in our areas of expertise and responsibility.

I would encourage you to continue working with the project team, as they are the best contact to keep you updated and to share your concerns and thoughts with on how the project affects your property.

Sincerely,

Shannon McCarthy
Public Information Officer

# Latest Alaska LNG report looks at community impacts

By Larry Persily lpersily@kpb.us

Aug. 9, 2016

*(This is the first in a series from the Kenai Peninsula Borough mayor's office, reviewing the second set of draft resource reports submitted by Alaska LNG to federal regulators.)*

Included with Alaska LNG's second draft reports to federal regulators is an initial look at what the project could mean to jobs, wages, housing, schools, highways, ports, airports and emergency services across the state. The report on the project's social and economic effects frequently raises the issue of impact aid funds — negotiated between the state and project partners and disbursed by the state — to help deal with the additional demands on public services and community needs.

**Resource Report No. 5, Socioeconomics**, filed July 15 with federal regulators, says job seekers moving to and within Alaska could be significant during construction of the **multibillion-dollar North Slope natural gas project**.

"It is likely that some job seekers from the Lower 48 and within Alaska would be drawn to areas of Alaska where job opportunities would be created during project construction," the report says, similar to what happened in the 1970s during construction of the trans-Alaska oil pipeline. This temporary economic migration for perceived employment opportunities "could be substantial."

A shortage of housing "would not necessarily" deter job seekers, the report adds. And while some hopefuls would find work, "others would remain unemployed for the duration of their stay in Alaska."

A lack of support and financial assistance to municipalities prior to construction of the trans-Alaska oil pipeline led to overburdened law enforcement, medical and educational facilities, the report notes. The intent this time is to deal with the impacts up front.

**ALASKA LNG FILES 10 REPORTS**

The socioeconomics report is among the 10 filed in July with the Federal Energy Regulatory Commission, as Alaska LNG continues its work toward assembling the soils, fisheries, air quality and other data needed for a complete application to FERC. An application would trigger the commission to start work on the project's environmental impact statement.

The July reports are the second set of drafts filed with FERC to solicit regulatory agency comments prior to the final reports and an application. The project sponsors — North Slope producers ExxonMobil, BP and ConocoPhillips, and the state — have not settled on a timeline for a FERC application or their next commitment of development funds.

Aside from well-paying direct and indirect project employment, many of the other jobs created in Alaska during construction — so-called induced jobs — "would be relatively low-paying jobs," adding to the housing concern, the report notes. Those jobs could include restaurant, retail or lower-skilled service-sector employment. "The ability of these individuals to afford adequate housing," the report says, "would be limited."

To help with the situation, the report says, "Private charitable institutions in Alaska may choose to involve themselves in providing housing assistance to transients." Transitional housing facilities in Anchorage and the Kenai Peninsula Borough, the report notes, "have little or no excess capacity."

In addition, any housing shortage during construction could put pressure on rents, placing a financial strain on Alaskans whose incomes do not increase with the project.

"The potential impact of the project on local housing will be provided in the FERC application after construction workforce estimates are available," the report says.

Help could come from impact aid, administered by the state, the report says, in particular if the municipal aid program covers the "increased need for housing, including affordable housing and related infrastructure and homeless shelters."

## IMPACT AID UNRESOLVED

State officials and affected municipalities from the North Slope to the Kenai Peninsula have discussed a possible impact aid grant program, funded by $600 million in contributions from the project sponsors in lieu of property taxes during construction. Details of the grant program for local governments, such as eligibility and disbursement rules, were discussed early in 2016 but not resolved by the state-managed Municipal Advisory Gas Project Review Board. The program would require changes in state law.

However, state control of the LNG project, an option advanced this summer by the governor, could change the funding source of the impact aid program if the North Slope producers take a reduced ownership share in the project. Further details of a state-controlled option are anticipated later in the year or next.

Housing is not an issue for workers in direct, on-site project construction jobs, who would be required to reside in self-sufficient construction camps, commuting on rotation from designated pick-up locations and returned to those locations at the end of each work period. Depending on the camp location, workers would be bused or flown to the sites, with airports in Anchorage, Fairbanks, Kenai and Deadhorse the main transit hubs.

"The construction camps are expected to be closed, with workers required to remain within the camp while off duty," until it's time to head home for their weeks off, Alaska LNG says.

**KENAI AIRPORT WILL BE BUSY**

The single largest construction job of the project would be the gas liquefaction plant and marine terminal in Nikiski, with an average 41,000 shift-change worker transports a year between Kenai and Anchorage during the heaviest employment in the third through fifth years of a six-year construction job. At its peak, that would add about 52 percent to the passenger volume at the Kenai Municipal Airport, though the number of flights would increase just 9 percent as the project would use larger aircraft for its charters.

"Consultations would be held with the Kenai Municipal Airport to identify potential solutions to handle the increased passengers," the report says.

Kenai Borough residents working at the Nikiski job site may be allowed to live at home, commuting to the work site each day.

Passenger traffic at Anchorage and Fairbanks airports would increase by 5 percent and 11 percent, respectively, at peak construction. The report says air charters would help reduce conflicts with summer tourism travel and lessen or avoid any disruption of commercial air travel.

"Due to the magnitude of project construction labor requirements," estimated to peak at 12,000 direct jobs, and the specialized skills required for multiple positions, "some jobs would be filled by temporary workers coming from locations outside Alaska," the report says. Many of those workers would come from the U.S. Gulf Coast, "a global center" for oil and gas activities.

Estimates of the number of people indirectly employed by the project, including Alaskans and relocated workers, will be included in the application to FERC. Information on construction payroll and wages during project operations also will be included in the final resource reports submitted to FERC with the project application.

Though the report lacks specific numbers for workers needed in each job category, it provides current (2014) statistics on how many skilled workers, by category, are underemployed or unemployed in Alaska, as an indication of the extent of an available workforce. For example, it shows that 582 electricians and helpers were working in comparable-paying jobs outside their occupation in Alaska in 2014, 245 were working in lower-paying occupations and 762 unemployed. Among plumbers, steamfitters, pipefitters and helpers, 397 were working outside the occupation, 216 were in lower-paying occupations, and 190 were unemployed.

**ADDED PRESSURE ON HOUSING, WAGES**

The indirect and induced jobs, and the job seekers, would put the greatest pressure on the smaller supply of temporary housing in the Kenai Borough, as opposed to the larger cities of Anchorage and Fairbanks, the report says. "Preparing for the housing demand in the borough during project construction may be difficult." In particular, housing could be tight during summer tourist and sportfishing season, before the construction camp is built in Nikiski.

The full potential impact of the project on local housing will be provided in Alaska LNG's application to FERC.

The second draft of the socioeconomics report also notes that the demand on community services and infrastructure would increase with the temporary boost in employment, in particular from workers not directly related to the project. At the same time as municipalities may need additional staff to provide services, "workforce retention may become an issue for some local governments, as high-paying project construction jobs may attract public service employees."

Increases in the cost of living, particularly housing, may add to the problem. Wage inflation could push employers to pay higher salaries as they compete for workers.

"The impact of immigration of people on public infrastructure and services will be provided in the FERC application," the report says.

As to school enrollment, Alaska LNG does not expect the workforce would result in a need for any new schools around the state. "It is expected that relatively few incoming project construction workers would bring their families," the report says, and those job seekers that move to Alaska with children "would be disbursed over several communities." However, any new students would require additional state and local funding and could increase class sizes.

**HEALTH CARE PROVIDERS COULD SEE IMPACTS**

"Another concern," the report says, "is that some economic in-migrants would have no regular health care provider and would use hospital emergency rooms as primary care access points." A lack of health insurance could add to uncollectable debt carried by health care providers. "The impacts to medical facilities and services" may be addressed by the state-administered impact aid fund, the report says. "Potential grant funds could be used for hiring additional medical personnel during the period of construction."

The report also cites the impact aid program in its discussion of the additional workload on emergency services personnel and law enforcement agencies in the state.

Though it's not all about drawing on impact aid to cover higher costs. The report notes that affected communities would receive additional revenue from the economic activity related to construction, such as municipal alcohol, car rental, hotel and sales taxes.

Fuel is another issue addressed in Report No. 5. Alaska LNG estimates it would need up to 7 million gallons per month of ultra-low sulfur diesel during peak construction demand. The report says the Petro Star refinery in Valdez and Tesoro refinery in Nikiski have "excess idle capacity" of about 11 million gallons per month and could handle the project's fuel demand, except maybe in the summer when in-state demand is at its peak — during which, some fuel may need to imported into the state.

Several hundred trucks would be needed to haul fuel and everything else to construction sites, and the report notes that trucking companies in Alaska have expressed concern over a forecast shortage of qualified truck drivers for the project. "Consultations would be held with the Alaska Truckers

Association to address this situation," the report says, adding that training programs may need additional resources.

**ROAD IMPROVEMENTS NEEDED**

State Transportation Department officials have told Alaska LNG that "some roads, highways and bridges would need improvements to bear the heavier and more frequent truckloads during project construction," the report says. In addition, "portions of the Parks, Dalton, Seward, Sterling and Glenn highways may need to be refurnished" after construction to repair the wear and tear.

Without specifically answering who would pay for any needed improvements or repairs, the report says: "A potential highway use agreement may provide mitigation for construction-related impacts." (Translation: It's negotiable.)

Peak truck traffic along Alaska's highways would be spread over five years, averaging about 14,000 truckloads a year on the Steese/Elliott/Dalton highways from Fairbanks toward Prudhoe Bay; 14,000 a year on the Seward/Sterling/Kenai Spur highways between Anchorage, Seward and Nikiski; and 19,000 loads a year on the Glenn/Parks Highway from Anchorage to Fairbanks.

Because traffic on the Dalton Highway to Prudhoe is much lighter than on the other, heavily traveled urban routes, Alaska LNG-related traffic during construction would boost average daily vehicle counts on the Dalton by about 50 percent, with only a single-digit percentage gain on the other highways. During peak work, the report says construction traffic could more than double the daily truck count on the Dalton Highway.

On the Glenn and Parks highways, truck pull-out areas, expanded truck weigh stations and additional passing lanes may be needed to accommodate construction traffic, the report says, though the project would maximize its use of the Alaska Railroad for moving freight to Fairbanks to reduce the load on the highway.

Hauling material from the ports at Anchorage and Seward to the LNG plant site in Nikiski would add to traffic on the Seward, Sterling and Kenai Spur highways. For example, looking at the Sterling Highway near the Skilak Lake Road intersection, about 40 miles southeast from the LNG plant site in Nikiski, Alaska LNG estimates about 90 trucks a day during peak construction. That would represent about a 3 percent increase in overall traffic at the location, but an 18 to 28 percent increase in truck traffic.

“Project-related traffic would contribute to the congestion that already exists along sections of the Seward, Sterling and Kenai Spur highways,” the report says. “The primary mitigation method for reducing additional traffic … would be to use barges and other vessels as much as possible” to move material from Anchorage and Seward to Nikiski.

The report acknowledges “particular public concerns” about traffic on the Kenai Spur Highway to and from Nikiski, especially the project’s intent to relocate approximately 1.33 miles of the highway to the east of the LNG plant site for safety and security reasons. “It is anticipated that the relocation would be completed prior to the start of project construction,” the report says, providing no other information on a route selection timeline.

A lot of material would move by rail out of Anchorage and Seward. So much so that the Alaska Railroad has told Alaska LNG that it would need a two-year advance notice to obtain more railcars to handle the traffic. Even with the additional capacity, the report says, there is a risk that the increased freight traffic “could cause congestion in the rail system, particularly during the summer tourist season when the number of passenger trains increases substantially.” To help relieve that stress, the project would coordinate with the railroad to move freight trains at night as much as possible.

**PORTS STATEWIDE WILL BE BUSY**

Several different ports of entry would be used, depending on their facilities and transport connection to construction sites:

- Anchorage would be the main port for containers and roll-on, roll-off truckloads from Seattle and Tacoma. At the peak of construction, Alaska LNG says project freight would add about 30 percent to the port’s annual container count. The report says the heaviest years of freight hauling would exceed the capacity of ships currently serving Anchorage, with enough demand to almost fill an additional ship on the route
- Seward would be used primarily for pipe and pipeline equipment. To ensure there is enough space to unload and stack each cargo of pipe segments, and to ease congestion at the port, Alaska LNG proposes using somewhat smaller vessels for deliveries. The report says it could take 120 days at the dock spread over three years to unload all of the pipeline shipments.
- Constant barge traffic would ferry materials to the LNG plant and marine terminal site in Nikiski, including approximately 10 barges on a weekly basis circulating between Anchorage,

Seward and Nikiski. Alaska LNG would build a "pioneer" barge landing (materials offloading facility) and then a much larger facility to handle all the seaborne deliveries, especially large production modules.

- Whittier, with its rail connection, would most likely be used as a port of entry for fuel deliveries.
- Dutch Harbor, in the Aleutian Islands, has often served as a U.S. Customs clearance port for modules on their way from overseas construction yards to Alaska's North Slope, and Alaska LNG expects it would use the same "well-established customs entry process" for its deliveries.
- West Dock, at Prudhoe Bay, would be expanded with dredging, a new dock head, widening of the access road and development of a new staging area to handle the sealifts of gas treatment plant modules and other materials. Barge deliveries likely would be limited to July through August, and during peak activity would add about 80 percent to West Dock traffic over 2014 numbers, the report says.

Also along the waterfront, the report notes that set gillnet permit holders would be displaced during construction of marine facilities in Nikiski and across Cook Inlet near Tyonek, where the project would establish a barge landing and work area for laying pipe across the inlet to Nikiski. Lost revenues to the salmon fishing permit holders along the shores could total $3 million during pipeline construction, the report says.

"Consultations would be held with affected set gillnet operators to mitigate potential economic losses during the construction period," Alaska LNG says.

enalytica

# AK LNG: Pros and cons of a state-led project

August 2016

## Contents



**Author**

Nikos Tsafos is President of enalytica.

## Point of departure

Over the past few months, the State of Alaska has proposed that the Alaska Gasline Development Corporation (AGDC) take the lead role in developing the Alaska LNG (AK LNG) project. Broadly speaking, a state-led project could mean:

Option 1. AK LNG becomes a state-owned, tolling project.

Option 2. Same as Option 1, but the state tries to lower cost of supply.

Option 3. AK LNG becomes a state-owned, merchant project.

What are the pros and cons of each structure? What are the core principles that should guide the state's efforts? And what questions should the Legislature be focusing on?

## Option 1. AK LNG becomes a state-owned, tolling project

**Project structure**. In this case, AGDC owns the hardware: the gas treatment plant (GTP), the pipeline, and the liquefaction and marine facilities in Nikiski. AGDC will sign long-term contracts with the producers, and maybe others, whereby the companies will pay AGDC a tariff to use the facilities. Should the state take its royalty in kind or its production tax as gas, the state (DNR/DOR) could become a shipper as well. AGDC will use these commitments to attract investors and/or secure third-party finance.

**Assessment**. This structure changes the capital call for the producers: ExxonMobil, BP and ConocoPhillips would spend money to further develop Prudhoe Bay and Point Thomson but they would not spend billions to build the infrastructure. Instead, they would sign long-term contracts to use the capacity. For them, the capital call for this project has fallen considerably.

This structure also removes some complexity and reduces risk for the producers. It might no longer be necessary, for instance, to negotiate a payment-in-lieu-of-tax (PILT) for property since the state will own most of the infrastructure that would be subject to property tax. It might not even be necessary to negotiate "fiscal stabilization," since the capital that the producers would put at risk would fall sharply.

But this structure does not, in itself, lower the cost of supply—if AK LNG is uneconomic, this structure is unlikely to make a major difference, unless the state were exempt from federal income taxes, a prospect which is yet unknown, or benefited from other tax exemptions (AGDC is exempt from property tax to state and local jurisdictions, although some revenue sharing would still need to happen). This structure also raises project risk to the state by shifting the burden of execution from the producers to the state.

### Option 2. Same as Option 1, but the state tries to lower cost of supply

**Project structure**. In this case, AK LNG moves to a structure similar to Option 1, but now the state takes on a more aggressive role in reducing the cost of supply. In effect, the state deploys non-engineering ways to lower costs—for instance, the state could reduce the rate of return used to calculate the tariffs for the GTP, the pipeline and the liquefaction facility. Lower returns would lower tariffs and thus lower the price at which the producers can sell gas to the market and still make an acceptable return. Lower returns, however, would also reduce the profits that the state can expect to make from AK LNG.

The state can also deploy its taxing power to impact project economics. Property tax, for example, is a major component of total project costs, and the state was already in discussions with the producers to come up with a mutually acceptable structure that both delivers a fair tax to the state as well as supports the project's development. In a state-owned project, AGDC would be exempt from paying property tax, which would impact the cost of supply—although the impact on communities would still need to be addressed and factored into the cost.

**Assessment**. It is hard to evaluate this possibility in the abstract. Sovereigns routinely offer concessions to support economic and industrial development; on their own, concessions tells us little about their advisability. It all comes down to specifics: what concessions, why, for how long, and so on.

Even so, there is one risk: that the state assumes, alone, the task of making AK LNG competitive. In other words, if there is a gap between the market price and the cost of supply, the state tries to close the gap by offering more and more concessions. This problem is particularly acute if the state sees AK LNG as a "must have," and is thus willing to take on too much risk or offer too many concessions to advance a project that is uneconomic. In this scenario, it is imperative to screen every concession and understand why it is being offered; it is similarly important to extract concessions from other parties so that the state is not, alone, trying to reduce the cost of supply.

### Option 3. AK LNG becomes a state-owned, merchant project

**Project structure**. In this case, the state owns all the infrastructure, as in Options 1 and 2, but instead of merely providing treatment, transport and liquefaction services in exchange for a tariff, the state buys gas at the wellhead from the producers and then re-sells it further downstream (for example, as LNG at Nikiski).

**Assessment**. Broadly speaking, the merits of this approach depend on specifics: at what price is the state buying gas and at what price is it selling it? These details are unknown, but one could envision two scenarios: either the two transactions are linked or they are not.

In a linked transaction, the state might buy gas from a producer at a price equal to Henry Hub and then sell it as LNG for a price also linked to Henry Hub plus a margin (say $7/MMBtu). In this case, the question is whether the margin covers the costs and return on the infrastructure. But it is not clear that the state provides any value—if the transaction makes sense, the buyer and seller would deal directly with each other, and one of them would pay the state a tariff for using the infrastructure (as in Options 1 and 2). The only value would come from adjusting the margin—but the state can do this without owning the gas (i.e. Option 2).

Alternatively, the state might buy and sell gas at prices that are not linked—for example, the state might buy gas at a Henry Hub price but sell LNG at an oil-linked formula. In this case, the risks for the state rise exponentially—as do, the theoretical returns if prices move in a way that favors the state. Such a deal, however, would not only require extensive due diligence; it would also require a very high risk tolerance.

How the state buys gas matters as well. On one extreme, one could imagine an arms-length transaction between the state and a producer. But one could also imagine a sale that is part of a leaseholder's "duty to produce." In this latter case, the state would need (a) to keep prospective buyers interested while the (likely lengthy) negotiations are completed; and (b) to ensure that the state does not put itself in a position where it is obligated to buy gas that it may not be able to resell at a reasonable price. As enalytica noted in the past, the liabilities involved with buying gas can run into the tens of billions (enalytica, "Negotiating firm withdrawal terms: Key issues," November 2015). Combined with a scenario where the state borrows money to build AK LNG, the state could be assuming enormous liabilities to make this project a reality.

## Some core principles to remember

**State-led project needs credibility boost**. A transition to a state-led project raises big questions about execution and governance. Can the state assume the leading role in driving one of the largest infrastructure projects ever? The state needs a plan for how it will do this, and it also needs a clearer delineation of responsibilities among state agencies as well as a clear blueprint for dealing with the producers.

**Don't expect to outsource risk**. The state cannot expect to take on a leading role, and full control, without assuming more risk—or, more precisely, while assuming that most of the risks will be borne by others (suppliers, contractors, banks, etc.). Nor should the state expect a large number of third-party investors to flock to the project in order to earn sub-par returns. Experience shows that infrastructure funds have limited appetite for liquefaction assets—and there is even less evidence that such investors would be happy with low returns.

**State cannot avoid partner veto**. The state places a high premium on not allowing any of its partners to hold back the project; for instance, the "AGDC-AK LNG Concept Document" (July 2016) states that its concept is "Very similar to the current structure except that a single party cannot hold up the entire development of the system." This might seem desirable but is, in reality, impractical: no investor would join a venture without having veto rights over major decisions such as whether to build the project (i.e. Final Investment Decision). It is especially unrealistic to expect that the state will not surrender any veto rights to investors who are asked to accept subpar returns and shoulder major risks.

**Don't overdo financial engineering**. Return is supposed to be a project-level, not a sponsor-level, concept: the return that an investor should expect should match the project's risk. In other words, AK LNG has an inherent risk that leads to an expected return. Moreover, leverage increases risk: if the state borrows to finance AK LNG, it should increase its expected return on equity. The idea that the state should, at the same time, lower its return threshold and increase debt exposure in order to make this project work would go against basic principles of corporate finance.

**Focus on risk-return.** Options 1 to 3 could easily be thought of as forming a risk-return continuum: Option 1 offers some benefits to the existing structure but may not suffice to make the project economic. Option 2 allows for more concessions—these could help if they are targeted and in response to specific concerns, and as long as other parties do their part as well. Option 3 seems to offer few benefits over Option 2 but substantially more risk—as such, its merits need to be stated very explicitly. Either way, the state is proposing a big increase in risk and thus, the key questions remain: what returns are acceptable for AK LNG? And how much risk is the state willing to take?

## Critical questions

As the Legislature evaluates these proposed changes, here are some possible questions to focus on.

**Why state ownership?** AK LNG has reached a stumbling block, but it is not obvious why state ownership is the only option available to AK LNG, especially since the primary benefits of the state taking over the project remain unproven. What levers are available to the state to reduce the cost of supply, and how much impact does each have? Is there a path that preserves the merits of the current approach while delivering some of the benefits of state ownership?

**What's the organizational plan?** The organizational challenges of developing AK LNG are immense and will require a major change in AGDC's capabilities and in cost. What does that look like, how long will it take, and how much does it cost?

**What's the project structure?** It is not clear, at this point, which path the state is following or why. Is the state looking to be an infrastructure provider? Or will it buy and sell the producers' gas? If the latter, why? What are the pros and cons of each structure from the state's perspective, and which path is being pursued?

**What's the plan for securing/confirming tax-exemption?** The exemption from federal taxation is a major argument for the state's increased role in AK LNG; what is the timeframe for confirming such status? How will tax exemption affect other aspects of AK LNG (e.g. issuing non-recourse debt)? What happens if that path is not successful?

**What's the financing plan?** LNG projects typically raise funds from the official sector, banks, and markets (bonds). But these have different costs and carry different risks. How do different financing scenarios impact project returns? What will very high leverage (say 90% or 100%) do to project risk given the amount of debt that would be needed to finance AK LNG?

**Who are the target investors?** Another critical assumption driving the state's efforts is the idea that third-party infrastructure funds will invest in the project, and will do so for returns that are lower than those of the producers. Liquefaction is generally not an asset that such funds have invested in, which raises the question: what case studies lead the state to believe that such investors will step forward? What returns will they require given the risks of the project?

**What's the risk-sharing strategy?** Many of the proposed risk mitigation strategies—that lenders will offer money at reasonable trades, that infrastructure investors will accept lower returns, that contractors will assume construction risk at a reasonable price, that future partners will waive their veto rights—are unproven at this stage and many seem implausible. A clearer definition of risk allocation would be most helpful, including the role that the producers will play in advancing this project forward.

# AK LNG

# PROS AND CONS OF A STATE-LED PROJECT

**Presentation to Joint Resources Committee Hearings**
**Anchorage, AK › August 24—25, 2016**

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# ASSESSING DIFFERENT STRUCTURES FOR AK LNG

**Different project structures**

Option 1. AK LNG becomes a state-owned, tolling project.

Option 2. Same as Option 1, but the state tries to lower cost of supply.

Option 3. AK LNG becomes a state-owned, merchant project.

What are the pros and cons of each structure?

What are the core principles that should guide the state's efforts?

What questions might the Legislature be asking?

# 1. AK LNG BECOMES A STATE-OWNED, TOLLING PROJECT

**Project structure**

State owns the hardware: the gas treatment plant, the pipeline, and the liquefaction.

State signs long-term agreements with companies to use its facilities.

The companies then pay the state a tariff for use of those facilities.

State could be a shipper too for royalty gas and/or tax as gas (if it chooses to take gas in kind).

State uses these long-term commitments to attract investors and/or finance.

**Assessment**

Main benefit is that this structure relieves the producers from their CAPEX burdens.

It also removes some complexity and risk (e.g. negotiating PILT, maybe even stabilization).

But this structure does not, in itself, lower the cost of supply (all depends on taxes).

Project risk also rises as execution burden shifts from producers to state.

# 2. Same as 1, but state tries to lower cost of supply

**Project structure**

State owns the hardware: the gas treatment plant, the pipeline, and the liquefaction.

State signs long-term agreements with companies to use its facilities.

The companies then pay the state a tariff for use of those facilities.

State could be a shipper too for royalty gas and/or tax as gas (if it chooses to take gas in kind).

State uses these long-term commitments to attract investors and/or finance.

State willing to accept a lower rate of return for tariff-setting purposes.

State lowers property taxes.

**Assessment**

Same as Option 1.

These changes can make a big impact on the cost of supply.

But, the state is effectively trying to make the project competitive on its own.

How are other parties (e.g. the producers) contributing to making project more competitive?

# 3. AK LNG BECOMES A STATE-OWNED, MERCHANT PROJECT

**Project structure**

State owns the hardware: the gas treatment plant, the pipeline, and the liquefaction.

State buys the gas at the wellhead, and sells it further downstream (e.g. FOB at Nikiski).

Gas sold either from arms-length negotiations or from leaseholders' "duty to produce."

**Assessment**

If the transaction makes commercial sense, state isn't really needed.

(e.g. If the state buys gas at Henry Hub and sells for HH+$7, producers can do deal directly.)

If the transaction takes on commodity exposure, risks and possible returns risk exponentially.

(e.g. If the state buys gas at Henry Hub but sells LNG at oil-linked price.)

If producers are willing to sell the gas, you probably shouldn't buy the gas.

(i.e. producers will only sell if it's a better deal than engaging market directly.)

Are the risks of a "duty to produce" approach fully understood?

# CORE PRINCIPLES

**State-led project needs credibility boost**

Any transition to a state-led project raises serious questions about execution and governance.

State needs to upgrade its capabilities—and will have to bear the cost of this.

**Don't expect to outsource risk**

It's hard to see why third parties will join this project and accept a sub-par return.

State cannot expect to take on full control while outsourcing risks to others.

**State cannot avoid partner veto**

State cannot hope to find investors who will not ask for veto rights over FID (at least).

(i.e. No investor will surrender the right to veto a boondoggle.)

**Don't overdo financial engineering**

Return is a project-level, not a sponsor-level, concept—it should match project risk.

Leverage increases risk, which increases the expected return on equity.

**Focus on risk-return**

What returns are acceptable for AK LNG? And how much risk is the state willing to take?

# CRITICAL QUESTIONS

Why state ownership?

What's the organizational plan?

What's the project structure?

What's the plan for securing/confirming tax-exemption?

What's the financing plan?

Who are the target investors?

What's the risk-sharing strategy?

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Fueling Alaska's Future

# AKLNG – Legislative Update

24Aug2016

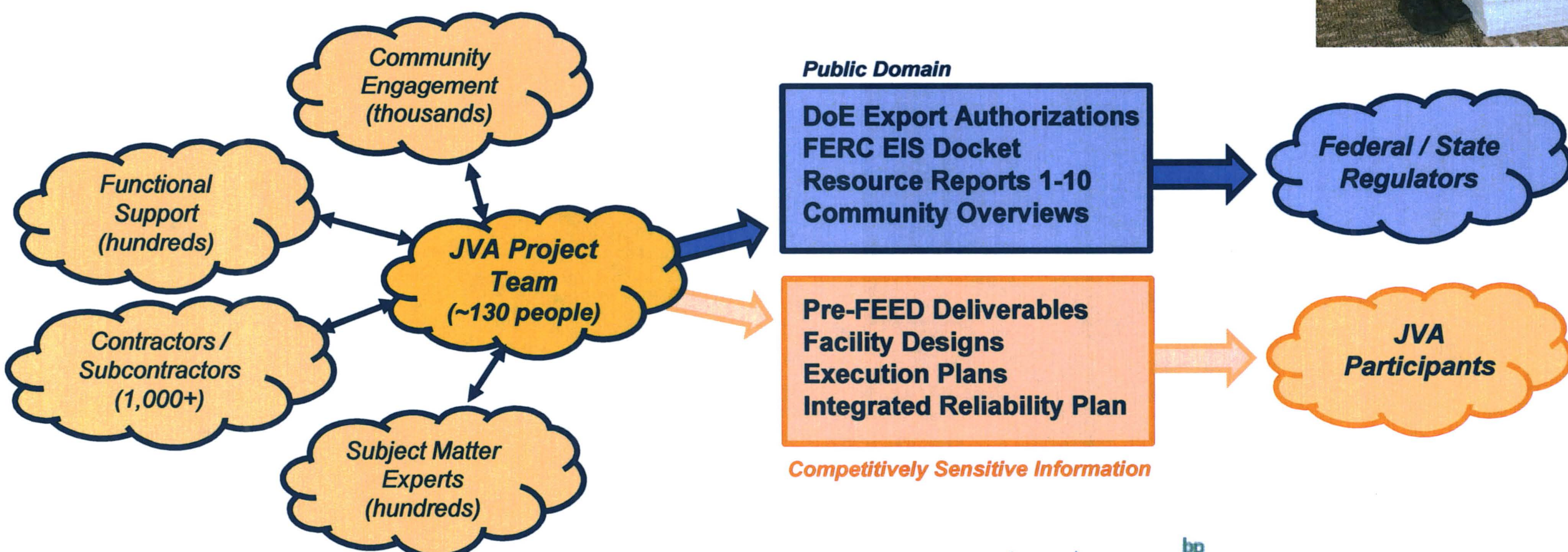
# Overview

Alaska LNG

**Pre-FEED JVA Project Summary**

- Continued strong safety performance, no recordable incidents since Oct14 (1 total)
- Spent $487M on Pre-FEED through July 2016 ($107M spent on Concept stage)
- Pre-FEED work scope is ~97% complete, updated to reflect Optimization work
- 2016 Summer Field Season work complete, provides information for permitting process
- Completed 'Draft-2' Resource Reports for FERC Environmental Impact Statement
- JVA Pre-FEED deliverables nearly complete, provide to participants by 1Sep16


**AKLNG Pre-FEED JVA Project Work Process:**




Alaska Gasline Development Corp bp ConocoPhillips ExxonMobil

# Pre-FEED Deliverables

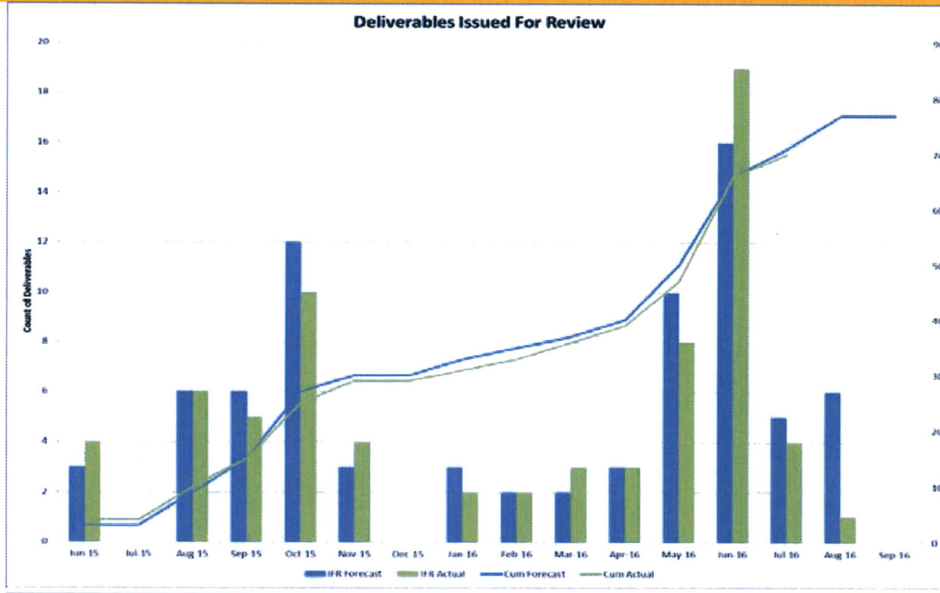
Alaska LNG™

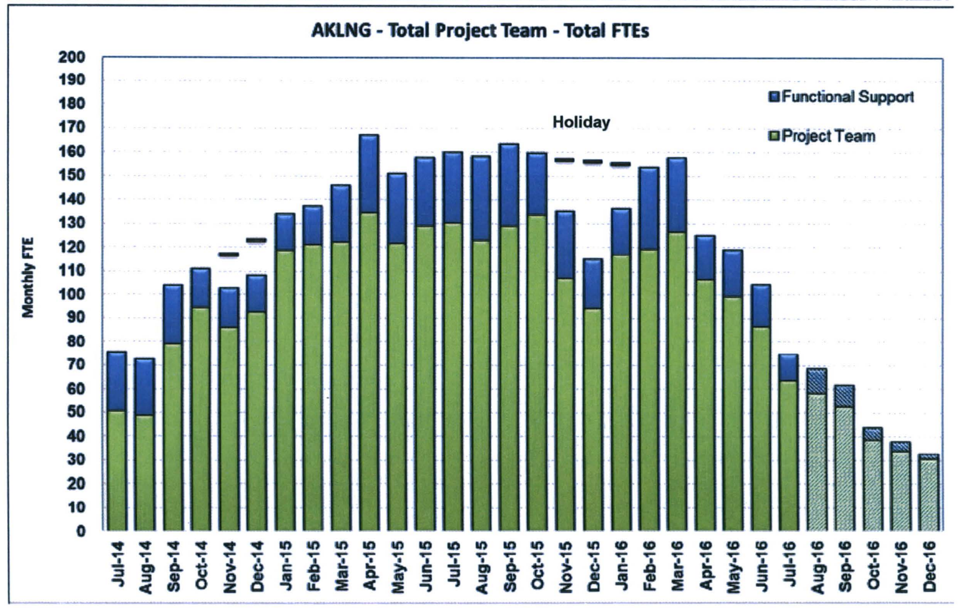
**Regulatory work progressing to secure required permits:**

- Draft 2 Resource Reports 1-10 filed with FERC (34,000 pages)
- Resource Reports 11 and 13 complete, pending review/filing
- Working to add data from 2016 summer field reports
- FERC and cooperating federal agencies reviewing material
- Expect extensive comments from FERC / other agencies
- Final filing material will need to address all comments

**Pre-FEED Deliverables (77) document plans for:**

- Project scope and design basis
- Safety, regulatory, environmental, socioeconomic, risks
- Technology plans
- Project execution and construction
- Contracting and procurement
- Cost and schedule estimates

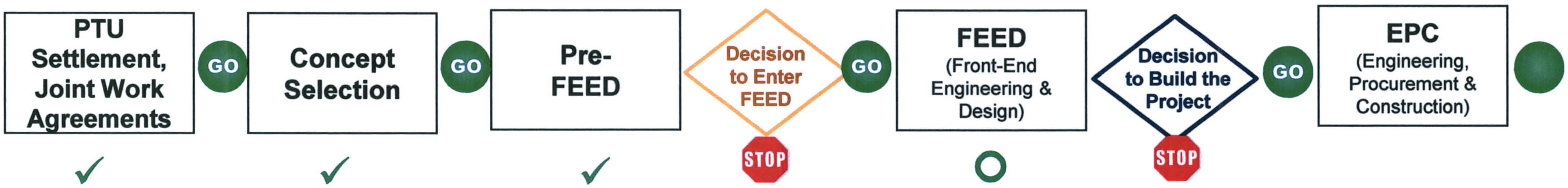



ConocoPhillips ExxonMobil

# Summary

Alaska LNG™




***Key Requirements for FEED Decision***

- **Viable Technical Option**
- **Key Commercial Agreements**
- **Government support**
- **Permits / Land Use Underway**
- **Potential Commercial Viability**

**Alignment**

- Agreed on design basis
- Unresolved commercial issues
- Fiscal terms undefined

**Risks**

- Regulatory / permitting in progress
- LNG market competition

**Cost**

- Capital costs reduced
- Cost of Supply may not be competitive

ALASKA GASLINE DEVELOPMENT CORP.

# JOINT RESOURCES COMMITTEE HEARING

## AUGUST 24, 2016

www.agdc.us

# Agenda

ALASKA GASLINE DEVELOPMENT CORP.

- **Recent Joint Key Messages**
- **AGDC Corporate Statements**
- **Refining the "Stage Gate"**

# Key Messages

ALASKA GASLINE DEVELOPMENT CORP.

**Where are we with the project?**

The Alaska LNG project continues to make good technical progress. Pre-FEED work is over 90% complete and Pre-FEED deliverables are anticipated by mid-September.

Planning for the transition to an AGDC-led Alaska LNG project is underway with the target for commencement by the end of October with completion by the end of the year.

# Key Messages

ALASKA GASLINE DEVELOPMENT CORP.

## What is happening with the transition?

The Parties are working together to consider commercial options to improve the project's ability to compete in the global LNG market.

Once transitioned, AGDC will be responsible for managing the project going forward including:

a) applying for regulatory approval,
b) securing the commercial commitments from gas sellers, shippers, and buyers necessary to acquire the equity and debt financing that will be required to complete the project,
c) preparing to start FEED.

# Key Messages

ALASKA GASLINE DEVELOPMENT CORP.

## Are the parties working collaboratively?

As part of the effort to improve the project's competiveness, the Parties are working collaboratively to transition the project to State leadership.

They are also pursuing alternative commercial structure options and concepts that have been successfully used in global LNG projects to reduce the Cost of Supply of the project.

The goal is to have a seamless continuation of the project and maintain project momentum.

AGDC, BP, ConocoPhillips, and ExxonMobil are currently holding transition meetings with a goal to enable a seamless continuation of the Alaska LNG project. These discussions have the goal of timely transfer of information, data and work product, as well as access to assets necessary for a successful FERC filing.

# Additional AGDC Messages

ALASKA GASLINE DEVELOPMENT CORP.

- AGDC has approved funding through FY2017. As part of the State's budgetary process, AGDC will provide a budget request to the Alaska Legislature for FY2018.
- AGDC will augment its current technical, commercial, and project management expertise as necessary, consistent with project progress and funding.
- AGDC plans to ensure the Alaska LNG project builds upon the tremendous expertise and accomplishments already invested into the project.
- The AGDC greatly appreciates the professional and cooperative way the parties have advanced the project to this stage and looks forward to working closely with them during the next stage of the project.

# Refining the "Stage Gates"

ALASKA GASLINE DEVELOPMENT CORP.

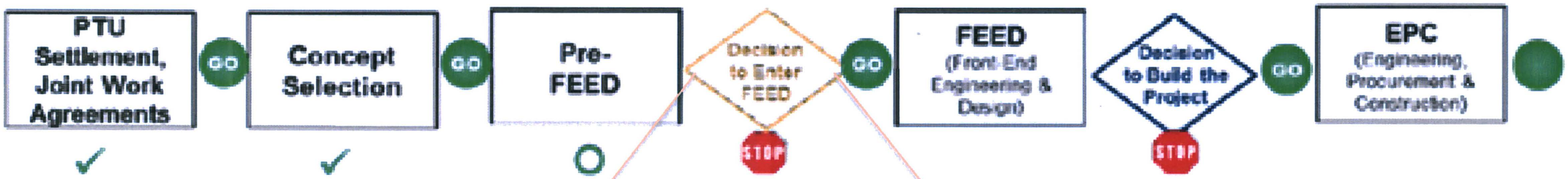



Diagram courtesy of AKLNG – Legislative Update 29Jun2016

## New elements in the "Decision to Enter FEED":

- Have we structured the project for tax and other financial efficiencies?
- Have we secured customers sufficient for financing?
- Have we identified and secured parties interested in equity investment in the infrastructure project?
- Have we identified and secured lenders for non-recourse project debt finance?
- Have we secured large EPC companies competent to manage the construction of the project and shoulder a significant part of the construction related risks?

# Summary

ALASKA GASLINE DEVELOPMENT CORP.

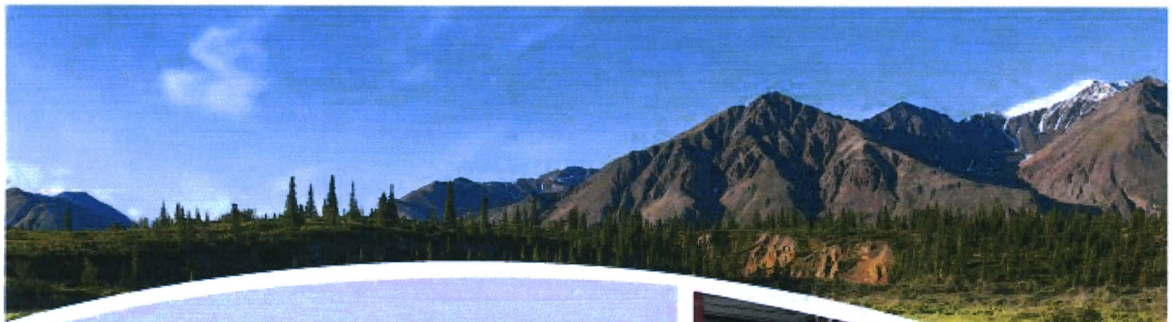
- AGDC has accepted the challenge to lead the Alaska LNG project.

- AGDC recognizes the project will need customers, adequate financing, construction contractors, and legislative approval to move forward.

- AGDC believes the AKLNG project can be made commercially viable and can compete in the global LNG arena.

- The project offers enormous benefits to Alaska and deserves the opportunity capture Alaska's share of the global LNG market.

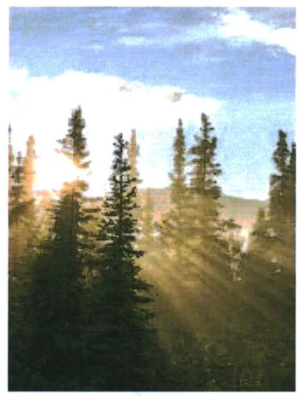
# Thank you



# ALASKA GASLINE DEVELOPMENT CORP.

## Questions and Answers

August 23, 2016



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## **Preface**

This document is intended for informational purposes only. The information contained is a work in progress and will be updated on an ongoing basis to reflect additional content or clarity. The document hereto is drafted by the Alaska Gasline Development Corporation (ADGC). The information expressed in this document are of those of the author and in no way intended to reflect upon any entity or person(s) other than AGDC. Any unlawful use, distribution, or copying by you or others utilizing this document is strictly prohibited. Please notify AGDC if you intend to utilize this document in any other method than otherwise specified.

We hope the information provided will provide clarity and insight with the Alaska Gasline Development Corporation. We are committed to Alaska Moving Forward: Delivering our natural gas and its benefits to Alaska and the World.

ALASKA GASLINE DEVELOPMENT CORP.

# AGDC Questions and Answers

**1. What is FEED?**

FEED stands for Front End Engineering Design. This refers to an amount of engineering work that is more than conceptual but less than detailed. The amount of engineering work involved in FEED can vary depending upon the desires of the project stakeholders including engineering contractors, regulators, and lenders. From Chiyoda, a major LNG contractor, FEED is described as follows: FEED means Basic Engineering which is conducted after completion of Conceptual Design or Feasibility Study. At this stage, before start of Engineering, Procurement, and Construction (EPC), various studies take place to figure out technical issues and estimate rough investment cost.

**2. What is happening with FEED for the gas pipeline?**

The Alaska LNG project is still in the preliminary stage called Pre-FEED. The Project is in the process of deciding whether to proceed to FEED and under what conditions. Currently, we are working together with the joint venture parties to consider commercial options to improve the project's ability to compete in the global LNG market. The next step is not necessarily to move forward to FEED, but rather restructuring the project to improve competitiveness. As part of the effort to improve the project's competiveness, the parties are working collaboratively to transition the project to State leadership. We are also pursuing alternative commercial structure options and concepts that have been successfully used in global LNG projects to reduce the cost of supply of the project. The goal of the joint venture parties is to have a seamless continuation of the project and maintain project momentum.

**3. Does FEED have to happen before construction?**

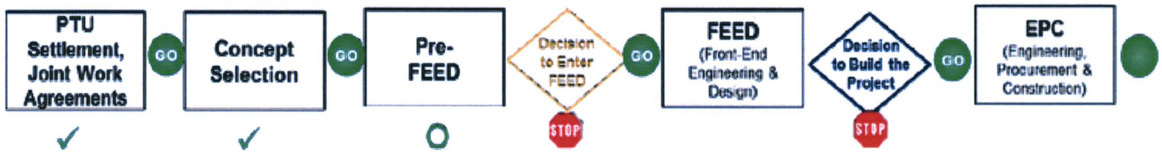
Yes, FEED always comes before construction. In order to avoid changes during a construction process or engineering, procurement, and construction (EPC) phase, FEED work is performed. Typically, enough FEED work is performed to allow major contractors to provide a reliable construction bid. FEED can also take place simultaneously during project development, such as the regulatory filing and marketing of the project.

**4. Where are we with the "Stage Gate" decision to move forward?**

Currently the Alaska LNG project is in the Pre-FEED stage. The pre-FEED phase of this project has been substantial, involving over $500 million of activity. This extensive level of pre-FEED has provided a reasonably good cost estimate, sufficient to provide pricing estimates for service. Prior to receiving firm construction bids and signing binding commitments necessary to obtain project funding, the FEED work will need to be performed.

## 5. Why is the project not going to FEED now? Wasn't that the original plan?

The plan after pre-FEED was to make a decision on whether or not to go forward with FEED. Below is a diagram from the Alaska LNG project that describes the major stages in an equity-funded stage gate process. Looking at the diagram, after the pre-FEED stage is complete, a decision is to be made to either "Go" to FEED, or "Stop." There is no time scale on the diagram, so the decision process to enter FEED can take a long time.




As part of the decision to move forward with FEED, the project developers look at many factors. Some of the factors the participants are looking at are absolute, such as whether the project is technically viable, and others are relative, such as whether the project is commercially competitive in the marketplace or financially practical for them at the present time. LNG projects typically involve large capital expenditures; these large capital projects may have to compete for capital within the organization against other large capital projects, including LNG and non-LNG projects. During times of low energy prices and related revenue, the competition for capital can be intense

The present competitive environment has caused many global LNG project developers to look for ways to make their projects more competitive; Alaska is no exception. The joint venture parties are currently exploring all alternatives to make the project more competitive in the global marketplace. Before we make the "Go" decision to progress with FEED, we need to make the project as competitive as possible from a cost of supply standpoint and explore alternative means to move the project forward.

## 6. What is the "cost of supply" and how can you reduce it?

From a producer and state perspective, the cost of supply involves the amount they must invest in the project to build it, supply it with gas from North Slope fields, plus ongoing costs of operation and production, including royalties, taxes, and other expenses.

To reduce the amount producers need to invest in order to build the system, we can do two main things: 1) reduce or "optimize" the design and construction costs, which the joint venture parties have already made significant progress in optimizing the system and lowering the expected construction costs, and 2) reduce the financial costs associated with the investment, finding the parties willing to lend and invest in the midstream infrastructure project at the lowest market rates in exchange for a steady reliable return.

## 7. Are third-parties willing to invest in the Alaska LNG project?

If we structure the project properly, have support from the producers and the state, secure credit-worthy customers, and engage major construction firms, then we can make the project attractive to infrastructure investors.

Large infrastructure funds, such as pension funds, mutual funds, utility holding companies and other risk-averse investors have demonstrated a significant appetite for U.S. pipeline and LNG projects. These investors are willing to accept lower returns for reduced risk and therefore can reduce the amount of investment required to be made by the project developers. This type of financing is called "project finance" or, in more elaborate programs as expected for this project, "structured finance" as opposed to the "equity finance" model, where project owners simply contribute their share of the project cost.

## 8. Are we sure it can get financed?

To get the necessary customer contracts and adequate financing lined up to build the project, there is still a considerable amount of work that needs to be done. We do know that the project will benefit from a reduced cost of supply.

One key to project financing is obtaining creditworthy customers to either buy LNG from the project or subscribe to the services that the project provides in order for customers to move gas down the system and convert it to LNG for shipment.

The current Alaskan gas producers could become customers of the system by subscribing to the services of gas treating, pipeline transportation, and liquefaction, or by buying LNG on a bundled basis at the Kenai loading facility. They could also facilitate the commercialization of the system by helping bring customers to the system.

Bottom line: we will need committed customers to get the system financed.

## 9. How do you get customers to sign up for LNG or services?

Getting customers is the primary objective of the marketing and sales program; without customers, we cannot secure the financing necessary to build the project. The upstream producer parties may be the primary customer base for the project depending upon how they decide to market their gas supply. The AGDC marketing efforts will also help support and augment the marketing activities of the upstream producer parties; these efforts include working in a collaborative manner with the producer parties to help the project become more competitive from a cost of supply standpoint and in developing service offerings to help commercialize their gas supply.

For third party customers outside of Alaska, AGDC will be promoting the Alaska pipeline and LNG project as a reliable and accessible source of LNG supply. There are many steps in the marketing program, but it begins by promoting the project to increase the awareness of potential customers and demonstrating to them that the project is on the path to be sanctioned. The Alaska LNG project has had very little exposure in the customer marketplace or opportunities to build the confidence of potential buyers that the project will be successfully built. Therefore, we have a lot of work to do to compete in the marketing arena - particularly in the current environment where many projects are competing for the same customers.

Service contracts and supply agreements will be drafted in accordance with accepted industry terms and conditions used elsewhere in large, third-party financed, LNG and pipeline projects, properly tailored for the Alaska project.

Furthermore, two key aspects of service become important for the typical utility buyers – price and reliability of supply. Alaska has an exemplary reputation for LNG supply reliability, and the route from Alaska to Asia is direct. The project components from the point of supply to the LNG delivery point can be designed with a sufficiently high degree of reliability to provide delivery assurance. Therefore, price will become a major focal point in our marketing effort. But, as mentioned, price is only one aspect of marketing.

It will be important to the marketing effort for the project participants and the State of Alaska to communicate support and confidence in the project. LNG purchase decisions are major commitments and undergo a thorough and lengthy review process. Projects that are facing strong headwinds in their home base are viewed much less favorably than projects that receive good local support.

**10. What are the advantages of an AGDC-led project?**

Federal taxes play a large role in the overall cost of supply. As a tax exempt entity, the state may be uniquely positioned to deliver one of the most impactful cost of supply reductions to improve the competitiveness of the project. Therefore, state ownership through an ADGC-led project may provide significant benefits to the chance of project success.

Additionally, AGDC is the only entity that has a singular mission and vision of maximizing the benefit of Alaska's vast North Slope natural gas resource through the development of infrastructure necessary to move the gas into local and international markets.

**11. Is AGDC planning to complete the project on its own?**

AGDC is not planning to develop the entire Alaska LNG project on its own. It would not be practical for the full scale integrated project. AGDC is managing the overall process of obtaining contractors, subject matter experts, project component managers, and others necessary to enable the project to move forward on a reasonable timeframe.

**12. Are the producers welcome to participate?**

The producer parties are absolutely welcome to participate, first and foremost as suppliers of gas and customers of the project. They will also likely have a significant role to play in the guidance of design and execution of the project, as anchor customers of any gas or LNG project do. Even in a state-owned project, there are opportunities to participate in the investment and funding requirements for the project by third parties. However, the return on investment expectation for a global energy production firm is likely higher than for infrastructure investment funds. Therefore, the proportion of their participation may be significantly less than what was originally anticipated under the all-equity model.

**13. Will AGDC need to use the permanent fund to pay for the project?**

AGDC is not considering use of the permanent fund to develop the project and has not been given any indication that the State of Alaska would consider using the permanent fund.

As part of the overall project funding process, numerous sources of project equity and debt will be considered. As stated above, if the project is structured properly, it will be attractive to infrastructure investors and lenders. If the State of Alaska is to be an equity investor or lender, it will have to address its desired funding mechanism at the appropriate time and in accordance with State law.

**14. Will the State have the opportunity to be an investor like the other sovereign entities that invest in LNG projects?**

Sovereign ownership is relatively common in LNG facilities; approximately 70 percent of LNG facilities in operation have a portion of ownership held by either the sovereign or a sovereign-controlled entity (30 out of 42 operational projects; source: WoodMackenzie 2016). AGDC feels the State of Alaska should have the first opportunity to invest further and will absolutely be given an equal opportunity to invest in this important project. Other sovereign entities have enjoyed significant returns from their LNG developments. Therefore, the State of Alaska as the project champion must be given that same opportunity.

ALASKA GASLINE DEVELOPMENT CORP.

## 15. Does AGDC have the experience to oversee such a large construction project?

AGDC does not plan to oversee the construction portion of the project. There are competent organizations with significant experience and expertise that would be contracted to oversee various segments of the project including construction management.

At this time, AGDC has the experience to manage vendors and service providers for the next phases of the project, which includes the FERC application filing, marketing activities, commercial structuring, financial structuring, engineering activities, and near-term project management.

AGDC will augment its current technical, commercial, and project management expertise as necessary, consistent with project progress and funding.

## 16. What companies build large projects like the Alaska LNG project?

There are a number of large, globally recognized companies capable of managing and building large-scale integrated projects like the integrated Alaska LNG project.

There are several companies that are qualified to handle this type of work, one of them is: Bechtel, who have built over 50,000 miles of pipeline; enough to circle the earth twice. They have also constructed one-third of the global LNG capacity and were involved in the construction management of the pipeline portion of the Trans Alaskan Pipeline System (TAPS). Another is Fluor, who teamed with Bechtel to manage the construction of the TAPS oil pumping stations and Valdez oil terminal.

There are a number of other globally recognized and competent contractors that have been involved in the construction of LNG terminals and pipelines. Global contractors by business volume in 2014 included: ACS (Spain) ranks number one; Bechtel (US) ranks third; Fluor (US) ranks fifth; Technip (France), with US LNG experience, ranks tenth; CB&I (US/Netherlands), an early leader in LNG, ranks 26th; Chiyoda (Japan) who were involved in the Alaska LNG project, ranks 44th. Other major contractors can all contribute to the successful completion of the Alaska integrated infrastructure project.[1]

## 17. If contractors take some of the project risk, won't they charge for that and won't that increase the cost of the project?

Contractors would charge for accepting some project risk. However, this will help control the exposure to cost overruns. The premiums paid are similar to insurance premiums, and may be offset by standardizing certain design elements to make the project easier to execute and finance. AGDC will conduct a thorough evaluation into the potential benefits and feasibility of

[1] http://www.enr.com/toplists/2015_Top_250_International_Contractors1

distributing project risks to contractors with the goal of placing each type of risk onto the entity best positioned to mitigate it.

**18. Does the project have to cost $45 billion or can it be less?**

The project team and subject matter experts are working hard to find cost efficiencies and reduce the overall project cost, while also putting controls in place to ensure there are no significant cost overruns. Additionally, the project can be developed in phases, which could significantly reduce the initial cost.

The gas treatment and liquefaction plants are each designed with three production "trains". At this time, the production trains are essentially planned to be constructed simultaneously. A phased approach could extend construction over a much longer period of time. Large scale LNG projects sometimes go through expansion phases separated by years. However, the economy of scale benefit is with full implementation.

The pipeline, similarly, has eight compressor stations which would be installed to match throughput requirements in a phased approach.

If the project was done in phases, the first phase would be less than the $40-45 billion projection, but a tradeoff is that the financial returns and pricing might be less attractive.

**19. Don't producers typically own the gas pipelines?**

There are very few examples in developed countries where the producers actually own and control gas pipelines. Unlike crude oil, which cannot typically be used by consumers in its raw state, natural gas is useable right off the pipeline for domestic needs such as residential heating and manufacturing. Consequently, pipelines, as the main infrastructure conduit to move the gas to consumers, are typically owned by pipeline companies that provide transportation as a service as their core business.

Prior to 1985, in the United States, pipeline companies were the buyers and sellers of gas in interstate commerce. After 1985 (FERC Order 436), the pipeline industry "unbundled" and pipelines became predominantly transportation companies providing transportation service to producers, end-users, and distribution companies on a contract carriage basis. The pipeline-as-transporter model is now the predominant model used worldwide in the gas transmission business.

**20. Do customers often own part of the LNG facility?**

The LNG industry has evolved over the last 46 years to a point where many of the major buyers have vertically integrated along the LNG value chain. This means they not only buy LNG, but also own LNG ships and often own a small portion of the LNG production facility and now even upstream reserves. Of the LNG projects in-service and under development, slightly more than half have a slice of buyer ownership. For those projects where the buyer is a gas or utility company, the ownership slice is typically small, and rarely controlling, but generally gives buyers a sense of comfort to have a "seat at the table" regarding the overall progress of a project.

**21. Will customer ownership push down the price?**

No, customer ownership does not generally decrease pricing. Competition pushes down the price. LNG sellers, including Alaska, will be price takers more and more. We are competing with other projects and the competition – also known as the supply and demand balance – is what predominately influences the price.

**22. If the state owns 100% of the project, how can it avoid the risk?**

The mitigation of risk in such a large project will be key to the overall project success. This is true even under the all-equity model where the State was expected to fund 25 percent of the project cost.

There are a number of large LNG projects, even recently, that have experienced cost overruns during construction. In an equity funded project, these costs are typically borne by the project sponsors.

The quantification, distribution, and management of risk is one of the biggest challenges in overall project management. In a third-party structured financed transaction, the risks will be specifically identified, quantified, and distributed to the party best able and willing to manage or absorb the risk.

Any risk that AGDC or the State of Alaska would consider accepting would be subject to a contractual agreement that would be understood and approved by all relevant agencies, legislators, and parties involved in the process.

To ensure clarity, neither AGDC nor the State of Alaska will accept an inappropriate amount of risk for this project.

**23. Is it a good time to be bringing an LNG project to market?**

It is the best time we have but, unfortunately, it is not a great time to be marketing LNG. Currently, the global LNG market is in surplus because of all the supply projects recently brought on line or currently under construction.

Fortunately, natural gas is in increasing demand worldwide, with Asia-Pacific nations leading the demand pull. It is safe to say by industry consensus that a supply/demand equilibrium will be reached in the early 2020's with more LNG needed by the 2022-25 timeframe.

There are many more supply projects that also desire to come on line to meet that demand. These new projects are all in various stages of development, like the Alaska LNG project, and therefore will be our primary competition.

The global competitive arena will be intense, with major competitors using new and improved tools at their disposal to compete. Customers will be demanding contract terms reflective of a buyer's market. Once the competition is over, and the dust settles, the LNG industry will most likely have existing LNG suppliers that have become stronger, nations that have entered the LNG export scene for the first time, states in the US that are engaged in LNG exports, and contract terms and conditions that favor buyers as well as work against new entrants.

Even though the market is not great for a new supply project, it is as good as it will get. Alaska must leverage its advantages to compete now for the future demand. An LNG purchase contract is a multi-billion dollar purchase commitment that would take an appreciable amount of time to negotiate and approve. AGDC's plan is to begin customer awareness and marketing now, with the intention of securing commitments in 2017/18 that would be necessary to underpin the financing needed to construct the project and reach the 2022-25 window of opportunity.

Although some people may question whether a market window will exist in the mid 2020's, if Alaska is not positioned to compete now, we will certainly miss the opportunity.

**24. What benefits does the gasline provide to the State of Alaska?**

Alaska LNG will create thousands of local jobs. Based on resource and labor research, the Alaska LNG project will bring 9,000-15,000 new jobs during design and construction. Additionally, about 1,000 jobs during long-term operations will be created. Studies have also shown that each direct job creates a ripple effect in the economy that generates 20 indirect jobs. In addition to workforce opportunities, the potential revenue from natural gas exports can contribute to the State's economy.

In addition to providing added export revenue, the gasline will significantly reduce the barriers to further exploration on the North Slope and provide reliable, reasonably priced, fuel for domestic projects such as mining and processing activities. It will also provide Alaskan residential consumers with additional long-term affordable gas supply for home heating and other needs.

**25. What if we do nothing; what if the gasline does not get built?**

If Alaska misses the next forecasted demand cycle in 2022-2025, other global LNG projects will capture the market share and further minimize the potential to monetize Alaska's vast natural gas resource for the foreseeable future.

Most likely, the new projects that come on line to serve the mid-2020's demand pull will provide an excess amount of capacity that will take another several years to fully absorb into the market. The 2030's may see another demand pull, but by that time there will be numerous other projects that are looking at expansion phases or are farther along in the development cycle.

**26. What are the next steps?**

There has been a substantial amount of technical and engineering work performed on the project up to this point. The next steps involve continuing the regulatory application process, structuring the project for tax and other financial efficiencies, securing customers sufficient for financing, identifying and securing parties interested in equity investment in the infrastructure project, identifying and securing lenders for non-recourse project debt finance, and engaging large EPC companies competent to manage the construction of the project which will shoulder a significant part of the construction related risks.

**27. Is the Governor directing the plan?**

Governor Bill Walker is a strong proponent of the Alaska LNG project, but AGDC has been given the charge and latitude to direct the plan in keeping with industry practices for natural gas infrastructure project development.

In the past, as well as today, the gasline and LNG project is recognized as a major infrastructure project that could literally pay dividends for generations. It will increase the wealth of Alaska, not take from it.

The Governor, as the State's leader, is responsible for appointing AGDC's Board of Directors who are charged with ensuring the corporation is properly staffed and managed to achieve its mission to build a North Slope gas pipeline and LNG infrastructure for the maximum economic benefit of the State and its people. Additionally, the legislature confirms all board members for AGDC.

The corporation is an independent, public corporation of the State of Alaska. It is separate and distinct from the State. Funding for the corporation's operations and accomplishing its mission is appropriated by the Alaska State Legislature. It is by their discretion that the Alaska Gasline Development Corporation continues to operate.

**28. What advantage does Alaska have over other suppliers?**

Alaska has one of the largest and most reliable supplies of natural gas in the world with a 46 year history of LNG exports. The gas is from a conventional reservoir, not from shale gas. Alaska has an ideal geographic location to serve the major LNG consumption markets in the Asia Pacific region with a direct route to Asian destinations. Alaska is one of the safest and most well-defended places in the world and has a well-developed political and regulatory climate.

All competitive advantages combined, Alaska is an excellent place for a strategic LNG supply location.

**29. Does the State have a chance to progress a successful project to completion?**

If properly structured, the Alaska LNG project should be attractive to infrastructure investors, private equity funds, retirement funds, and other investment organizations. Yes, we absolutely have a chance, but we have an intense global competition ahead of us amongst the biggest players in the industry. Therefore, we need to be prepared. We need to ensure unified support throughout the state. With all of Alaska behind this project, it will not fail.

**30. What can Alaskans do to help support the project?**

The most important ways that constituents can support the Alaska LNG project is by staying informed and communicating your support to your representatives.

If you would like to stay informed about AGDC and our projects, please join our email list to receive meeting and event notices, news releases, and other public information. Visit https://agdc.us/updates.php to sign up.

ALASKA GASLINE DEVELOPMENT CORP.

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GAS FOR ALASKANS

**AGDC Responses to Senator Giessel Questions**
**August 23, 2016**

1. ***What is the target range for cost of supply?***

   Target range for cost of supply is normally driven by the least and most expensive marginal supplier. This target shifts over time as market conditions change. Therefore, rather than targeting a specific number, a project always has to strive to be competitive relative to the size of the available demand and other projects at a similar stage of development. At the moment this range appears to be driven by other major competing projects in the US Gulf and East Africa that can deliver similar volumes of LNG to the Asian market in the same time frame. Cost of supply is not the only determinant of competitiveness, but it clearly plays a large part. At the moment, AGDC and other project participants have a significant amount of external market information that places Alaska LNG toward the bottom of competitiveness scale, and that needs to be addressed through project re-structuring.

2. ***What is your timeline for securing access to gas?***

   Access to gas can come in several forms, such as contracts to ship gas on the project or wellhead sales to shippers who are not gas producers. Normally, final agreements on LNG purchase and sales contracts and upstream gas supply contracts are executed simultaneously directly before project financial close (or FID), so that pricing and other terms are fully aligned. However, intermediate option agreements can be concluded sooner. Some of the bi-lateral gas access discussions have already begun, and AGDC envisions continuing those with upstream resource owners with increasing levels of commitment over the next two years as the project continues its development.

3. ***What steps are being taken to secure buyers?***

   AGDC will be promoting the Alaska pipeline and LNG project as a reliable and accessible source of LNG supply. The AGDC marketing efforts will help support and augment the marketing activities of the upstream producer parties. The upstream producer parties may be the primary customer base for the project depending upon how they decide to market their gas supply.

   Service contracts and supply agreements will be drafted in accordance with accepted industry terms and conditions used elsewhere in large, third-party financed, LNG and pipeline projects, properly tailored for the Alaska project.

***4. EPC Contractors***

***a. When do you foresee hiring a Project Management contractor?***

We plan to solicit and contract with a Program Management Contractor (PMC) over the next 2 months to augment our in-house owner's staff and have the PMC on-board for transition with AKLNG Project Management Team by the end of 2016.

***b. What is that procurement process? How long do you anticipate it will take?***

We plan to use the same process to solicit for program management assistance on the ASAP Project to stand-up a full PMT capability to meet the needs of the project. We are specifically looking for a PMC with oil and gas mega-project experience, ideally with Arctic experience. We have started compiling information to determine the recent level and breadth of experience from potential contractors to narrow the field down from nearly 20 to 5 or 6 qualified firms. Next step will be formal solicitation of the top tier firms with Request for Proposal and formal review and award process.

***c. What are the components of that contract?***

AGDC needs to have program management expertise to augment our limited in-house owner's staff. The scope of the PMC will include solicitation and recommendation of primary support contractors for LNG / Marine, Pipeline, and Gas Treatment Plant subprojects; consolidated contract management for PMT contractors; primary engineering oversight of engineering companies; primary contractor billing review and payment; project processes, systems, and procedures for PMT; project controls and reporting; scheduling and cost estimating integration; integration of engineering between engineering contractors; and EPC planning and contract management strategies. The contract will be phased to pace with the level of project activity.

***d. What will the term and scope be?***

The scope of the contract will be to provide program management and technical expertise to advance the project through FEED, EPC, and construction of the project.

***e. What do you anticipate the cost will be for the PM contractor?***

We will develop cost estimates for the PMC in future phases of the project.

***5. When will you file for the draft EIS?***

The environmental review process is triggered by a Natural Gas Act Section 3 application to FERC. Please see response below.

***6. When will you make FERC application?***

The earliest that FERC will accept a FERC Natural Gas Act (NGA) Section 3 application is 90 days after it accepts Resource Report 13 (RR 13) from the project. However, because of the volume of data submitted by AKLNG, we have indicated to FERC that 120 days of review would be acceptable. RR 13 is scheduled to be submitted to FERC on September 2, 2016. AGDC is planning to submit a complete application in early January 2017 depending on the amount of re-write necessary from FERC's review of the second drafts of the resource reports. AGDC will also need to demonstrate that it has control of the lands at the LNG plant site. Commercial negotiations are underway with the owners of the AKLNG Project LLC to gain that control.

***7. When will you enter FEED? Expected FID?***

AGDC does not plan on commencing FEED until several milestones have been accomplished including securing customers to subscribe to services or LNG supply, equity and debt financing to build the project, large construction contractors and others willing to protect against cost overruns, and legislative approval.

***8. Funding***

***a. The Legislature's appropriations have been based on 25% of the costs, with the 3 partners funding the other 75%. How much will the New Concept Plan need and in when to meet your proposed timeline?***

AGDC's go-forward plan will cover all of the project development until we have partners that share the costs of progressing the project. Until additional funding becomes available, AGDC will advance the project with existing funds. The priority work effort will be the filing of the Section 3 FERC application. Secondly we will continue to interface with FERC, federal and state regulators and the public as FERC advances the EIS. The EIS is expected to be complete in second half 2018. AGDC has enough funds to file the application and interface with FERC through fiscal year 2017.

***b. What supplemental funding request will you be making to the Legislature in January 2017?***

AGDC does not anticipate requesting any supplemental funding for FY17. We are building our budgets currently and will submit through the OMB process for both capital and operating needs in FY18 and beyond.

***c. With today's budget shortfall, how do you propose to forestall a slow-down due to funding constraints?***

AGDC will live within our means (funds remaining in the AKLNG and In-state Pipeline funds) and will request future funding through the appropriation process.

d. ***What are expected spend rates through FY 17?***

AGDC anticipates spending its budgeted funds in FY17 to cover corporate operations, cash calls to cover our portion of AKLNG's 2016 work program, preliminary AK LNG FERC activities, and regulatory efforts to complete the SEIS for the ASAP project.

e. ***What are your plans for bringing in others to provide funding?***

AGDC is actively seeking partners to advance the project and will keep the legislature informed of agreements and funding authorization needs.

Wood Mackenzie

A Verisk Analytics Business

# Alaska LNG Competitiveness Study

August 2016

Strategy with substance

www.woodmac.com

# Disclaimer

- This report has been prepared for BP (Exploration) Alaska Inc , ExxonMobil Alaska LNG LLC and Alaska Gasline Development Corporation ("the Clients") by Wood Mackenzie Limited. The report is intended solely for the benefit of the Clients and its contents and conclusions are confidential and may not be disclosed to any other persons or companies without Wood Mackenzie's prior written permission.

- The information upon which this report is based comes either from public domain sources or from our own experience, knowledge and databases. The opinions expressed in this report are those of Wood Mackenzie. They have been arrived at following careful consideration and enquiry but we do not guarantee their fairness, completeness or accuracy. The opinions, as of this date, are subject to change. We do not accept any liability for your reliance upon them.

# Agenda

1. Project Overview and Scope
2. Alaska LNG Base Cost of Supply Competitiveness
3. Non Capex/Opex Options to Reduce the Cost of Alaska LNG Supply
    a. Third-party owned Tolling utility
    b. State-owned tolling utility
    c. Changes to the Fiscal Regime
4. Conclusions

## Scope of Project

- **A consortium of interested parties (specifically BP, ExxonMobil and Alaska Gasline Development Corporation) has engaged Wood Mackenzie to undertake an analysis of the competitiveness of the Alaska LNG project**

- **The analysis undertaken relies on Wood Mackenzie's own internal databases and publicly available information. We have not been provided with any proprietary information by any of the companies for whom this study is being provided. The following are the areas that are addressed in this report:**

  » Establish Alaska LNG base case Cost of Supply (CoS) and define the target range for a competitive CoS for Alaska LNG

  » Identify viable options in addition to base capital cost (capex) and operating cost (opex) reduction to reduce the project's CoS

  » Consider the way forward to allow for a globally competitive LNG project in Alaska

# Executive Summary

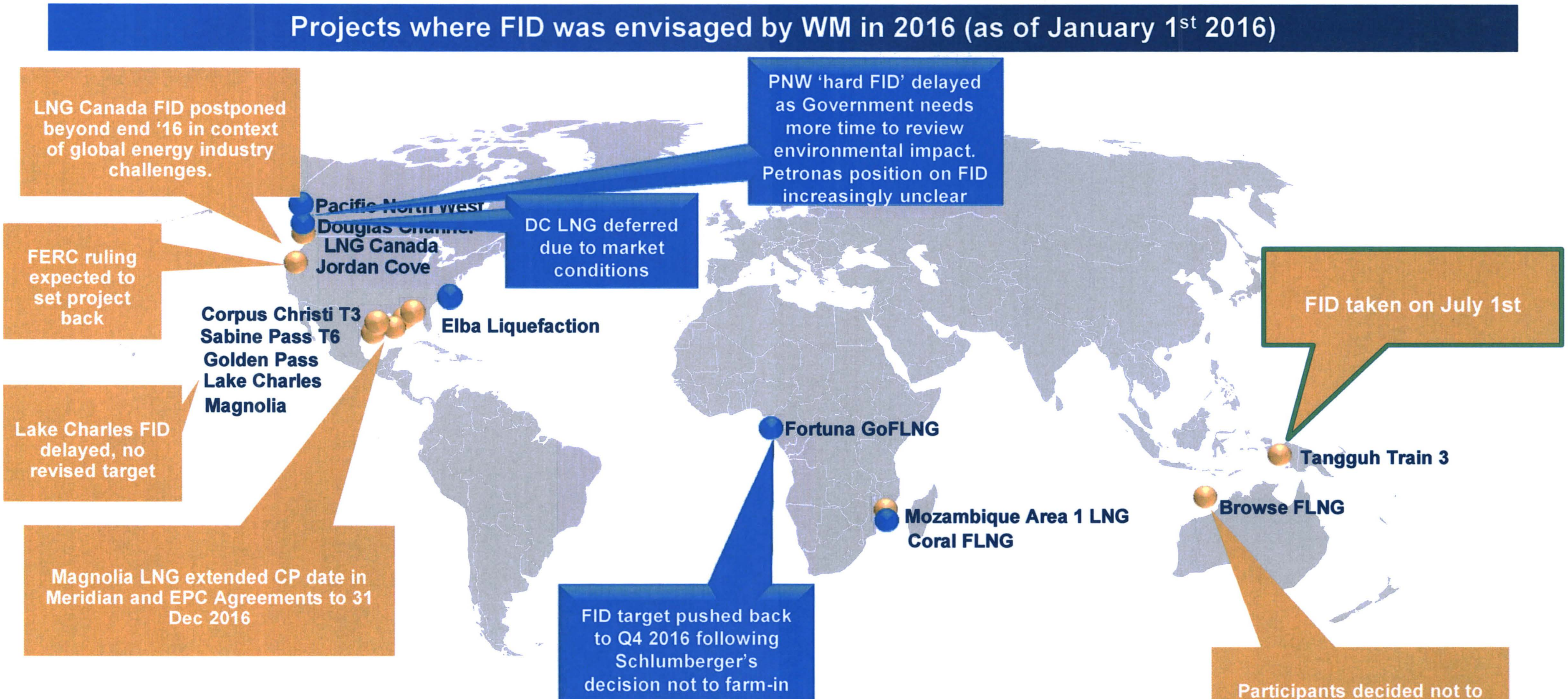
- Currently the competitiveness of the Alaska LNG project ranks poorly when compared to competing LNG projects that could supply North Asia, specifically, Japan, South Korea, China and Taiwan.

- This ranking also means that not only will the project not make sufficient returns for investors at current LNG market prices, but it may struggle to make acceptable returns even under a US$70/bbl price

- There are certain levers that could be used to improve the competitiveness of the Alaska LNG project and potentially also improve the competitiveness compared with other jurisdictions

# Agenda

# Several projects targeting 2016 FID have already pushed their timetables back




**Other developments**

- **Abadi FLNG moved onshore and FID pushed back to 2020 from 2018**
- **Oregon LNG funding pulled**
- **Triton LNG cancelled**
- **Cameroon LNG put on-hold**
- **Sempra indicated FID on Cameron LNG Expansion may be delayed beyond planned H1 2017 window**



Wood Mackenzie
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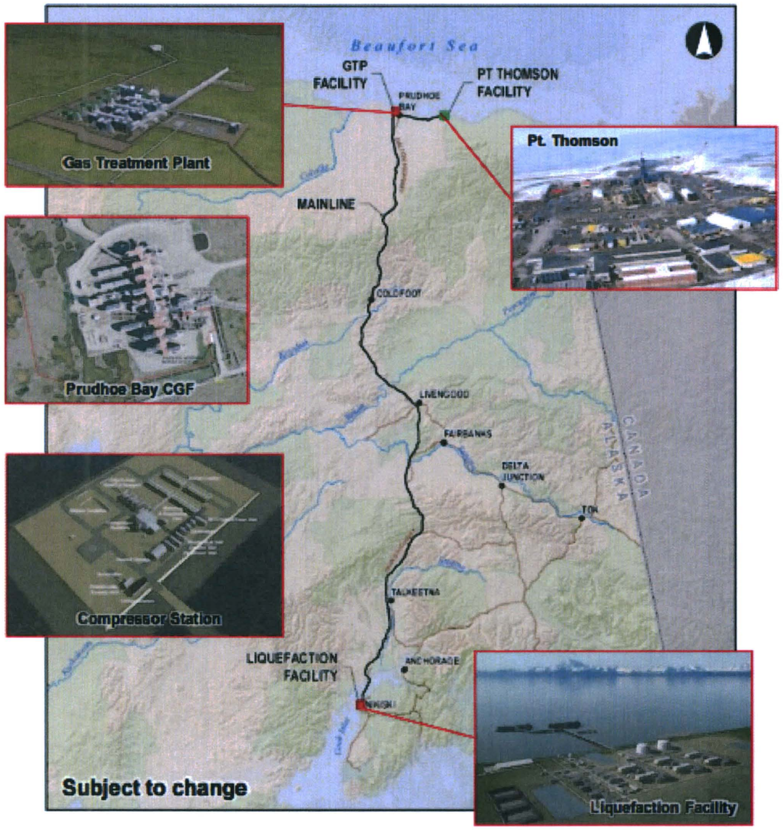
# Alaska LNG – Project Overview

Alaska LNG™

***An integrated liquefied natural gas export project providing access to gas for Alaskans***




**North Slope**

**Point Thomson:** Deliver natural gas to GTP

**Prudhoe Bay:** Deliver natural gas to GTP, receive $CO_2$ / impurities for further handling

**Gas Treatment Plant (GTP):** Clean, dehydrate, chill and compress 3.5 BCFD of natural gas and deliver to pipeline

**North Slope, Interior & Southcentral**

**Gas Pipeline:** Transport 3.3 BCFD of natural gas over 800 miles to Nikiski, with at least five interconnection points for in-state gas

**Southcentral**

**Liquefaction Facility:** Create, store, and load up to 20 million tons of LNG per year (15-20 LNG cargos per month)

ConocoPhillips ExxonMobil

-2-

## Approach to Analysis – Breakeven Cost of Supply

- **The basis of our analysis is to determine the breakeven delivered cost of supply for the Alaska LNG project**

- **The analysis provides the price that would be required (in US$/mmBtu) for a project (or different elements of the project) to break even i.e. the price required for the project to generate a deemed rate of return**
  - For the purposes of this analysis a return of 12% is used as a base case

## Assumptions – Costs and Volumes

- **In line with published cost cases, two capital cost cases have been run covering transmission lines, gas treatment plant, pipeline and LNG liquefaction plant costs**
  - » Low Case US$45 billion
  - » High Case US$65 billion

- **Upstream costs are estimated by WoodMac at around US$10 billion to cover future capex for gas development at Prudhoe Bay and Point Thomson**

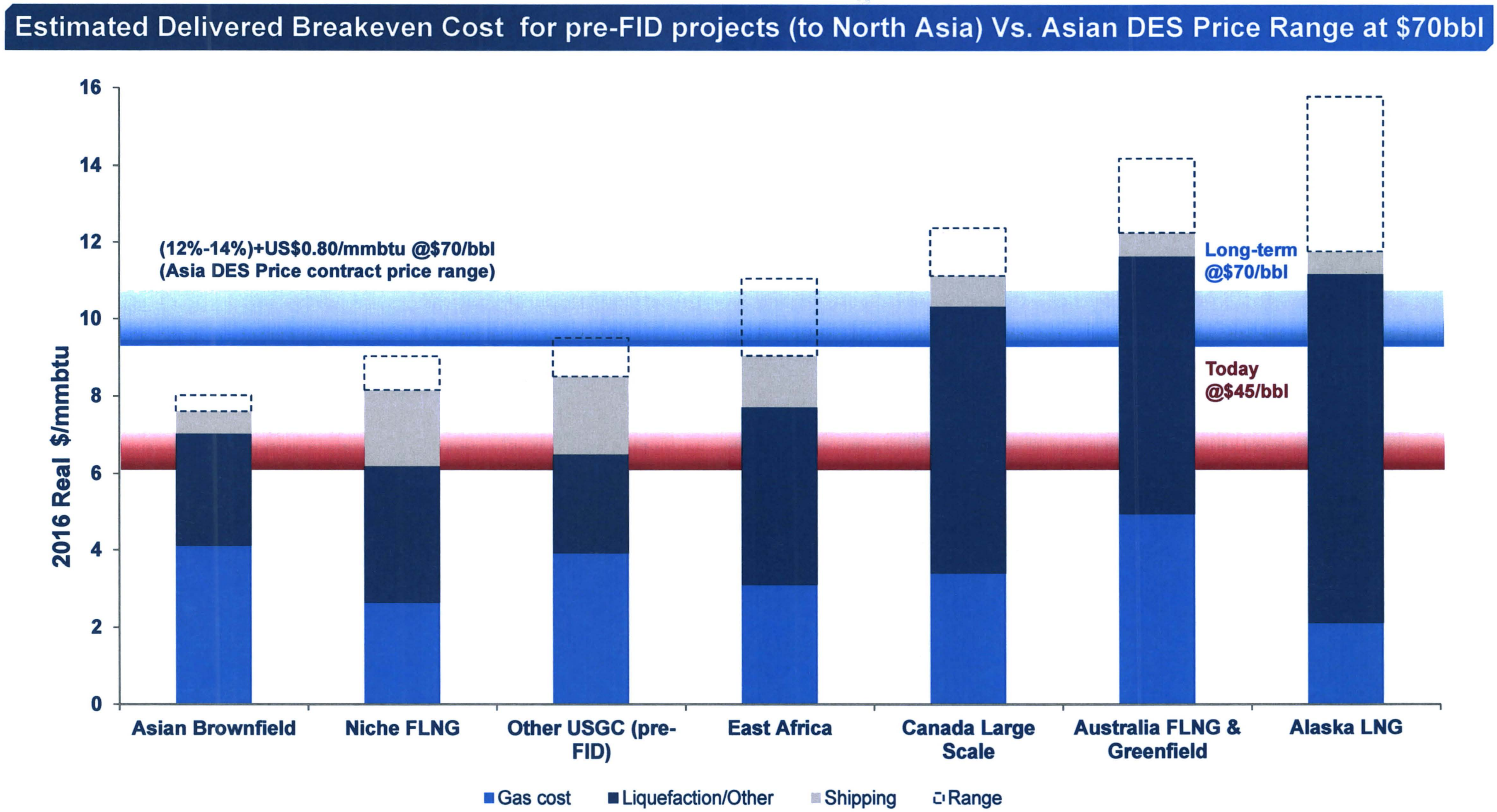
- **Shipping costs from Alaska to North Asia assumed at US$0.60/mmbtu**
  - » Point of reference: US Gulf Coast LNG projects' shipping to North Asia ~US$2/mmbtu

- **Upstream production 3 bcf/day**

- **Assumed losses 11%**

- **Domestic Market allocation: 300 mmcf/day**

# Comparison of Breakeven cost of supply for delivery into North Asia




**Notes:**
**Breakeven costs are calculated on the basis of a 12% return**
**UG Gulf Coast (USGC) LT HH ~$3.41 avg real price 2019-2030; gas cost is grossed up at 15% for losses etc**

# Comparison of competing projects

- **Of the peer group of projects, Alaska LNG has amongst the highest break-even cost of supply, even at the lowest capex estimate**

- **None of the listed projects break even at current oil prices of around US$45/bbl**

- **Under a long term price assumption of US$70/bbl, more would break even. However, the most economically challenged projects are:**

  » Canada Large Scale

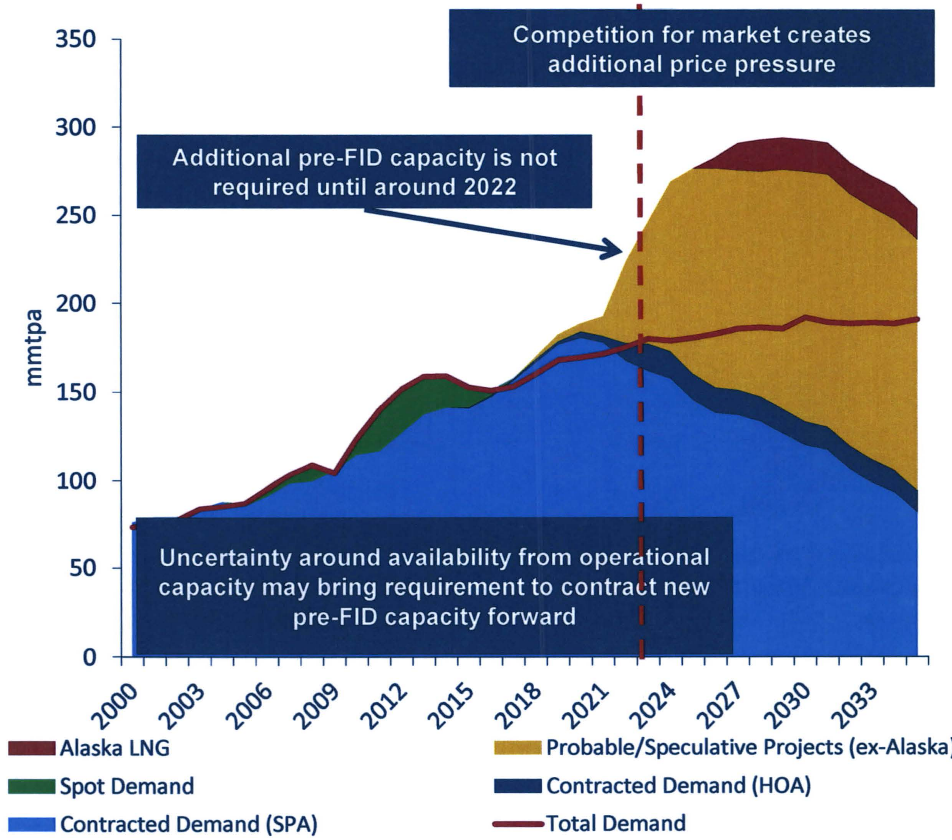
  » Australia FLNG and Greenfield

  » Alaska LNG

# North Asia has a significant requirement for additional LNG, but price is not the only factor that buyers take into consideration

## North Asia LNG demand vs. Contracted supply

- Maintaining a geographically diverse portfolio is important
- Contractual flexibility increasingly important
- Reliability and longevity of supply
- Significant number of competing pre-FID LNG projects plus un-contracted supplies from existing projects




Source: Wood Mackenzie

*Probable and Speculative projects reflects effective capacity of pre-FID projects aimed at supplying North Asia*

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## Approach

- **We have considered what other options may allow a reduction in the project breakevens**
- **A reduction in costs is an option that will undoubtedly reduce breakevens and two costs cases are considered**
- **The following options are covered within this section of the report:**
  - » The effect on competitiveness by including a conventional non-recourse debt structure in a tolling plant structure
  - » Restructuring the project to increase the Alaska State's share
  - » Relief from federal or state taxes

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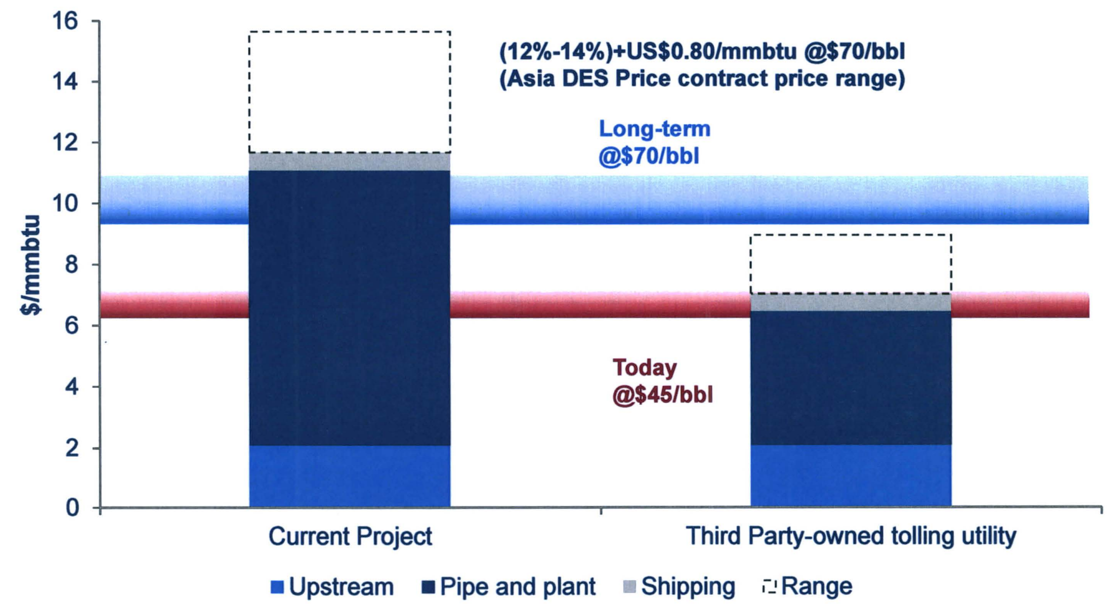
# The introduction of a debt funded third party tolling structure will reduce the cost of supply

- **The debt structure assumed is:**
  - » 70:30 – debt:equity
  - » 15 year repayment term
  - » Interest rate of Libor + 3.5%

- **A third party tolling company could require a 'utility rate of return' which is typically around 8%**
  - » This reduced requirement for a return reduces the cost of supply

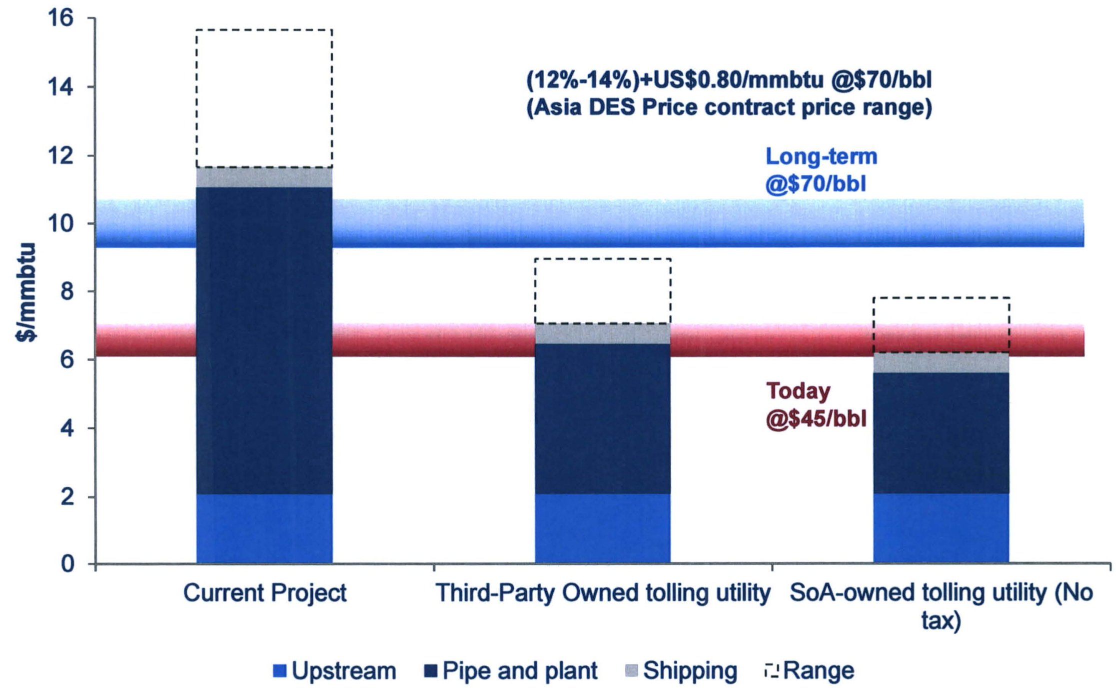


## Agenda

# The introduction of State ownership

- In addition to a third party toller, the State of Alaska (SoA) could further reduce the cost of supply with a potential tax exemption

- SOA-ownership shown as fully tax exempt



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# Changes to the Fiscal Regime

- **Targeted fiscal changes are often used around the world to encourage the development of a specific asset or a type of asset and there are many examples of this**

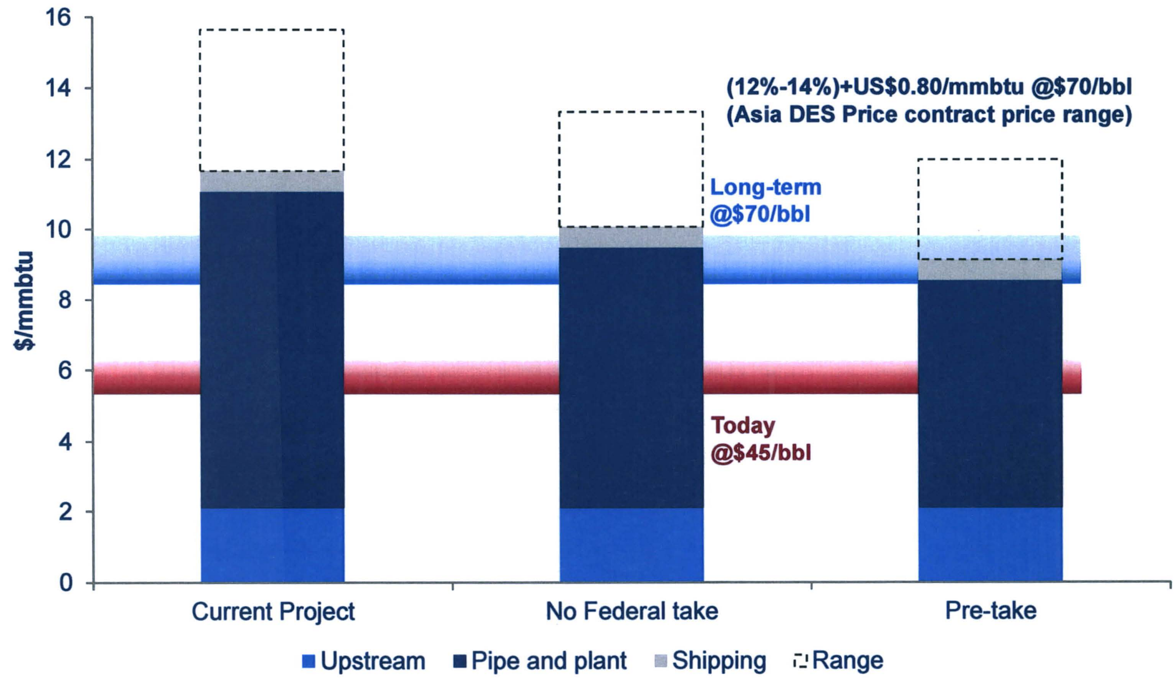
- **Typically relief will be granted for assets that are**
  - » high cost,
  - » found in unhospitable locations, or
  - » have low profitability under existing terms

- **The Snøhvit LNG project in Norway and the Yamal LNG project in Russia are examples of LNG projects where governments have targeted fiscal reliefs to enable these projects to progress**

- **Details of the changes used, plus examples of other targeted and more broadly applied fiscal reliefs are included within the Appendix**

# Impact of Federal and State fiscal change on integrated structure

- **The chart illustrates the cost of supply impact of changes to the fiscal regime on the integrated 100% equity project**
- **Even the removal of all taxes on pipeline and plants is insufficient to reduce the cost of supply below the current level of LNG prices**
  - The pre-take case excludes all levels of government take on the plants and pipelines but includes 25% RIK/TAG



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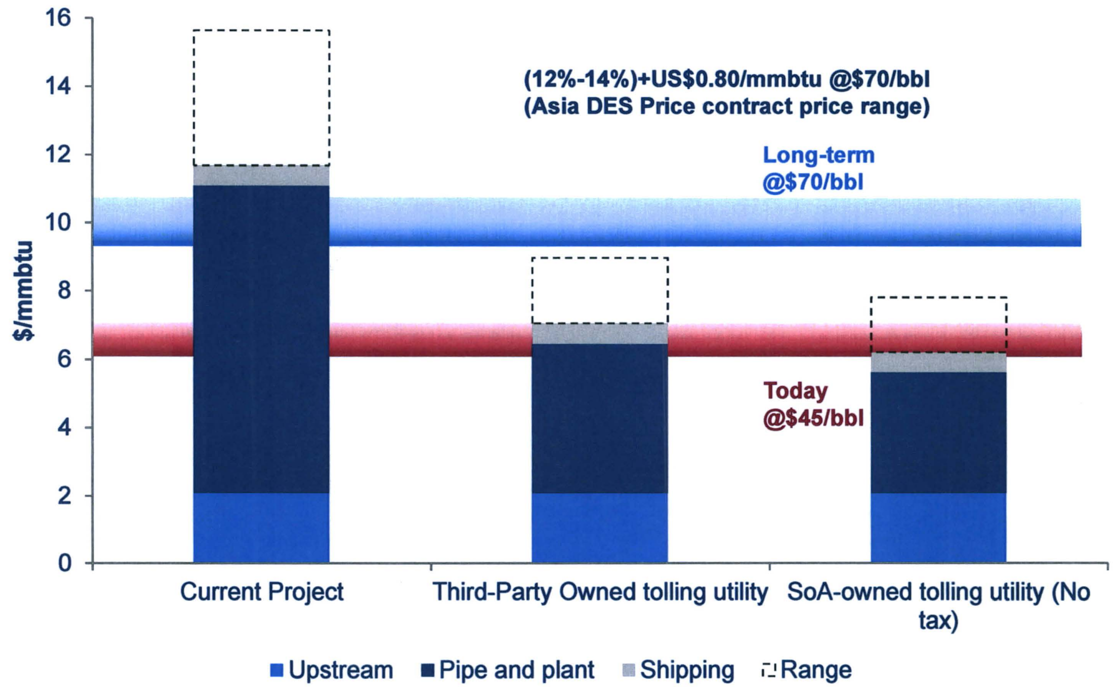
## Agenda

1. Project Overview and Scope
2. Alaska LNG Base Cost of Supply Competitiveness
3. Non Capex/Opex Options to Reduce the Cost of Alaska LNG Supply
    a. Third-party owned Tolling utility
    b. State-owned tolling utility
    c. Changes to the Fiscal Regime
4. Conclusions

## Conclusions

- Currently the Alaska LNG project is one of the least competitive on a cost of supply basis compared with other pre-FID LNG developments
- The State has different levers to assist in the development of the project:
  - » State support for a tolling utility-like return, debt financed project
  - » Increasing its stake beyond its current 25%
- Analysis has not accounted for benefits from:
  - » Monetization of State's gas share
  - » In-state gas supply
  - » Job creation
  - » Enabling new exploration and third-party access



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# Appendix

# Targeted reliefs originally driven by a specific project – LNG Projects

- **Snøhvit - Norway**
  - The project is an upstream project together with an LNG facility offshore Northern Norway. Originally the project was to be taxed as two entities: an upstream phase and a downstream phase, but the project economics were unsatisfactory.

    The terms for this project allowed faster depreciation (straight line over three years, as opposed to six years for other offshore developments) for LNG projects but would treat all of the development under the offshore taxation regime. This arrangement was enough of an incentive for the partners to agree to proceed with the project.

    However, a challenge was made on the grounds that this was an anti-competitive subsidy. This resulted in a change to the rules to amend the law covering LNG projects to give this tax incentive to projects falling within a geographically defined area in the northern part of the country.

- **Yamal LNG – Russia**
  - The Russian government was supportive of the project and provided tax incentives to encourage the development of the project. LNG and gas condensate are exempt from Export Duty and the project has received a 12-year Mineral Extraction Tax (MET) and Property Tax holiday.
  - These fiscal incentives have significantly helped the economics of the project, and without them its commerciality would be challenging.

# General Reliefs – targeted across a broad range of assets

- **US Gulf of Mexico**
  - » Historically reliefs were given against royalty for deeper water developments
  - » For awards made in the period up to July 2007 the royalty rate for developments in over 400 metres of water was 12.5% compared to 16.67% for shallower water projects
  - » For awards made up to July 2010 royalty suspension volumes were granted generally for leases located in over 400 metres of water, with progressively higher volume reliefs granted for leases awarded in deeper water

- **Colombia**
  - » Lower royalty rates are charged for heavy oil developments (API<15º)
  - » Unconventional oil and gas projects have even lower royalty rates and High Price Payments do not commence until a higher price is achieved
  - » Deepwater projects have a higher threshold for the commencement of High Price Payments and will typically have a higher exempt volume threshold

# Targeted reliefs originally driven by a specific project – Non LNG Examples

## United Kingdom – Various

- A number of different upstream developments in the United Kingdom were provided with reliefs to encourage their development. However the nature of the relief was such that it could not be made specific to one field, rather it was structured to be available to any similar field development, although some of the conditions to qualify were very narrow
- Deepwater Gas Field Allowance –
  - In January 2010, the government announced that value allowances were to be extended to include remote deepwater gas fields in the UKCS. The qualifying criteria included a minimum water depth of 300 metres, a minimum distance of 60 kilometres to infrastructure with ullage, and more than 75% of reserves should be gas. Those fields that were 120 kilometres from relevant infrastructure would receive the maximum £800 million value allowance. This reduced to zero on a straight line basis for fields 60 kilometres from infrastructure.
- Deep New Fields West of Shetlands Allowance
  - In its March 2012 Budget, the government introduced a value allowance of £3 billion (maximum of £600 million per annum) for fields in the West of Shetlands. To qualify, fields must lie in a water depth of over 1,000 metres and hold reserves of 25 million tonnes of oil equivalent (180 mmboe) or above. The total allowance was reduced on a straight line basis from £3 billion for fields with recoverable reserves of 40 million tonnes of oil equivalent (285 mmboe) to zero for those fields with up to 55 million tonnes of oil equivalent recoverable reserves (390 mmboe). These allowances were effective for fields sanctioned after 27 March 2012.
- Large Shallow Water Gas Field Allowance
  - In July 2012, the government created a further value allowance incentive for large, shallow water gas fields sanctioned after 25 July 2012. Gas fields in water depths of less than 30 metres, with reserves between 353 and 706 bcf qualified for a £500 million value allowance. This reduced to zero for fields with reserves of 883 bcf and above. At least 95% of the recoverable reserves must be gas for the field to qualify. If two or more fields were sanctioned at the same time, the £500 million allowance will be divided between the projects based on the ratio of recoverable reserves.


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# State Financial Participation in an Alaska Natural Gas Pipeline

- **The History**
- **The Project**
- **The Options**
- **The Costs**
- **The Risks of State Participation**


***Prepared by the Alaska Department of Revenue***
***January 31, 2002***

PETRIE PARKMAN & CO.

CH2M HILL

STATE OF ALASKA

Department of Revenue

Office of the Commissioner

Tony Knowles, Governor

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January 31, 2002

The Honorable Tony Knowles
Governor of Alaska

The Honorable Rick Halford
Senate President
Alaska State Legislature

The Honorable Brian Porter
Speaker of the House
Alaska State Legislature

The Honorable John Torgerson
Chairman, Joint Natural Gas Pipelines Committee
Alaska State Legislature

Dear Governor Knowles, President Halford, Speaker Porter and Senator Torgerson:

It has been six months since Senate Bill 158 was signed into law, calling on the Department of Revenue to prepare a report on the merits of state ownership or financing of an Alaska Gas Pipeline project. In those six months my staff, our consultants and I have spent considerable hours looking for the light at the end of the pipeline. We had hoped that light would lead us to clear and convincing answers to the questions: Should the state invest in a natural gas pipeline? If so, where would the state get the money? Are the rewards worth the risks? Would state financial participation in the project help bring about the start of construction?

Although we have reached the end of our assignment, we did not find answers to every question. It was like finding the light at the end of the line, only to discover that you don't have the authority to turn the switch on and off. Although we believe the financial risks to the state are substantial, it is possible that some would decide—as a matter of public policy—that the state should take such sizable risks in an attempt to exercise greater control over its own destiny.

As for finding the money for state participation in a project, Alaska is a little short on cash these days—unless you go into the Permanent Fund, which presents several legal and political constraints. Clearly, one answer is that state participation perhaps could be a plus if the state could issue tax-exempt bonds to help finance the multibillion-dollar project. But that switch is in federal hands.

We believe our report sheds new light on old discussions, and serves as a reference book on the project. Our work includes:

- A comprehensive review of the history of Alaska gasline proposals.
- A summary of current gasline proposals and potential sponsors.
- An analysis of the issues of state financial participation—how much money would be needed, and where could it come from.
- An explanation of what could or could not work for state financing—and why not.
- And what are the risks of putting up state money.

I believe our report provides you—and the Alaska public—with the information needed to make informed decisions.

In closing, I would like to thank our two consultants on this report: Dave Gray of CH2M Hill and Bill Garner of Petrie Parkman & Co. Mr. Gray is director of energy economics for CH2M HILL's Bellevue, Washington, office, and Mr. Garner is in the Houston office of Petrie Parkman, an investment banking firm that specializes in oil and gas issues. Their technical assistance was key to the success of this report.

As you read through this report, please call on the department for any additional information you need. I look forward to working with you on this project, which is so important to Alaska's future.

Sincerely,

Wilson L. Condon
Commissioner

# Executive Summary

The purpose of this report is to examine whether the State of Alaska should financially participate in a pipeline to transport natural gas from Alaska's North Slope to domestic or foreign markets.

The legal and fiscal issues today are not much different than the gas pipeline concerns Alaskans have grappled with over the past 30 years. During that time, the state and private groups commissioned several reports both favoring and dissuading state financial participation. Although the issues have not changed much, certainly the legal, regulatory, market and fiscal situation today is much different than that of decades ago.

Today, proponents of state involvement cite three main reasons for the state to participate in ownership or financing of an Alaska Gas Pipeline project:

- It would be a good investment with a healthy rate of return and minimal risk.
- Alaska should control its own financial destiny and development of its resources.
- State involvement would enhance the project's feasibility—that is, the pipeline would stand a better chance of getting built sooner if the state was a financial partner.

The answers, however, are much less clear than the questions.

## A Good Investment

The state is in a precarious financial position as it starts 2002. Its ability to provide essential services will be tested as the Constitutional Budget Reserve Fund runs out of money. The Department of Revenue projects that the reserve fund, which has helped cover state spending for all but two years since 1991, will hit empty by Labor Day 2004. Alaska may be resource rich but we are cash poor—unless you count the Permanent Fund. Other than taking money out of the Permanent Fund to invest in a gasline, the state is in no position to write a check for any significant investment in a gas pipeline project, regardless how good the investment.

## The Alaska Permanent Fund

There are several options for using the Permanent Fund for state investment in the project:

- Spend money from the Earnings Reserve Account to buy in as a gasline partner. This means going into the business of owning and operating a natural gas pipeline. This could be done by a legislative appropriation to another state agency or new state corporation to make an equity investment in the pipeline. However, withdrawing too much from the Earnings Reserve Account could jeopardize its future ability to pay for inflation proofing of the fund's principal and dividends.

- The legislature could change state law to authorize a direct investment by the Permanent Fund in the gasline business. A statute change would be required because the Permanent Fund's investment authority does not cover going into the gasline business.

- Or the Permanent Fund, as part of its regular asset allocation and investment mix, could decide to buy shares in a public traded corporation or buy bonds issued by the corporation or corporations that own the pipeline. These investments, however, would give the state no more control over the project than any other minority shareholder, and any return would depend on the corporation's performance and stock or bond value. Any such investment would—by constraint of the Prudent Expert Rule for Permanent Fund investments—be limited to a small percentage of a pipeline corporation's stock or debt.

## Taking on State Debt

The state and its municipalities are looking at how to pay for several billion dollars of school construction and repairs, and deferred maintenance to public facilities. The state, which has not issued any general obligation bonds in nearly 20 years, will go to market in the next year if legislators agree with the governor's proposal for school bonds. Taking on new debt for schools and other needs most likely will consume all of the state's available debt capacity, unless Permanent Fund earnings are diverted from the dividend program to pay debt service.

Any over-ambitious reliance on debt to finance a state investment in the gasline could jeopardize Alaska's credit rating, which could have a domino effect as it raises the cost of borrowing for the state and municipalities.

### Rate of Return

The Federal Energy Regulatory Commission in the United States and the National Energy Board in Canada would regulate the rate of return on any interstate pipeline, and we expect that return would not differ significantly from what the state—or the Permanent Fund—could earn in other investments with similar risks.

### Risks to the State

State investment as a partner in the project could put the state at financial risk if there are construction overruns, delays in completion of the project, unbudgeted calls for additional capital, or volatile natural gas market conditions. Unlike large corporations, the state does not maintain reserves for such risks, and it would be a difficult policy call to tell the public that key government services might be cut back to make money available for gasline expenses.

## State Control

Proponents who advocate state financial participation in the project for reasons of control raise two points: (1) Alaska should take a stronger hand in managing its resource development, and (2) a belief that North Slope oil producers took advantage of the state by inflating tariffs on the Trans-Alaska Pipeline System, thereby reducing their oil tax and royalty payments to the state.

Both are emotional issues, and both require an unemotional review.

First, whether the state should take an active role in managing the development and marketing of its oil and gas resources is a public policy call. If people believe that is the overriding issue in this project, then it might justify the financial risks to the state. However, advocates of this position should carefully weigh the risks against the potential benefits. Could state participation in the gasline make it happen any sooner? Would state participation dissuade corporations from putting up their own billions—private money that Alaska needs. And is it the role of government to build and operate for-profit ventures? We believe the state could best control the development of its resources by regulating their extraction and use, and could best profit from its resources by levying reasonable taxes on the companies that profit from their development.

Second, whether the state received less revenue because of the oil pipeline tariff structure—as some have alleged over the years—is immaterial to the gasline. The Federal Energy Regulatory Commission would regulate the gasline tariffs, and the state would have full access to those proceedings—regardless whether it had a so-called "seat at the table" as an active partner in the business. The state would not gain any more control over the gasline tariff as a business partner than simply participating in the federal regulatory proceedings as the State of Alaska.

And, assuming the state was not the sole owner or majority owner of the gasline, its seat at the table would most certainly be a minority seat with little or no ability to influence any major corporate decisions. The state would have more authority with its own statutes and regulations to influence project management decisions than as a minority business partner.

It is also important to note that even if the state had a seat at the table as a partner operating the gasline, the state could not use any information from the table in tax or regulatory proceedings on the project, nor could it use any of the proprietary information to compete with its other partners for natural gas sales. Confidential information set out on the table would have to remain at the table.

## Helping the Project

The two biggest hurdles to building a project to carry natural gas from Alaska's North Slope to market are: (1) the risk of construction cost overruns, and 2) the risk that in periods of low market prices either the pipeline operators or the shippers would suffer a loss. State participation as a business partner would do nothing to lessen either risk and, in fact, some might argue that state involvement in building and operating the line could add to the cost.

Although people talk more and more about running government like a business, the truth is government is not a business. It has rules and regulations and procedures and public access laws that could present formidable problems should government sign on as a partner with a private business venture. Nor surprisingly, none of the oil and gas and pipeline industry representatives interviewed for this report saw much, if any, benefit to having the state sit on the board of directors of a gasline venture. Many listed such state laws as open meetings, public records and procurement codes—not to mention the entire process of public policy decisions—as key reasons not to take on the state as a partner. Speed and decisiveness are essential to running a multibillion-dollar construction job and company, and, unfortunately, it's highly possible that state involvement would detract, not add, to the operation.

But the largest risk to any partner in the gasline venture is that there could be periods when the market price for gas is not high enough to cover the cost of moving the gas to market and still leave an economic wellhead value for the producers. There is no guarantee that year in and year out, over the entire life of the project, the market will be such that profits will flow to everyone involved in the gasline. Someone—the gas producers or the pipeline owners, if they are different than the producers—would have to take the risk that some of the gas sometimes could move to market at a loss.

If the producers build and operate the line to move their own gas, they would take the risk. If pipeline companies build the line, they and the producers could negotiate which of them shares how much of the risk. Either way, state participation in the project would do nothing to eliminate that risk.

For example, the gas flow at 4 billion cubic feet per day would be worth $14 million a day at $3.50 per million Btu. Perhaps two-thirds or more of that $3.50 would go toward the tariff—the cost of moving the gas to market. If the market price were to drop below that cost, the financial loss could be significant to anyone sharing in the risk. A market price just 10 cents below the cost of moving 4 Bcf per day to market would add up to a $400,000-a-day loss for whoever is contractually bound to the price risk.

Finally, the oil and gas and pipeline companies on the list of potential sponsors simply do not need the state's money to build the project. Their own finances are strong enough that they could either just write a check or raise the money they need from commercial financing sources or by issuing corporate bonds.

It appears state financial participation would do nothing to move along the project, unless the state could find a way under federal law to issue tax-exempt debt to own and/or finance the project. The lower cost of tax-exempt debt could help tip the project toward economic feasibility, and that could be a proper role for the state to take in assisting in the development of its natural resources. Even with the lower interest rate on tax-exempt debt, however, it is still possible that the companies might choose to issue their own taxable debt in order to take advantage of the federal tax benefits of owning and depreciating the line.

As it says in the cover letter to this report, there are no easy answers.

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SECTION 1

# Introduction

This report analyzes opportunities for the State of Alaska to financially participate in a pipeline to transport natural gas from Alaska's North Slope to domestic or foreign markets. The project is generally referred to in this report as the Alaska Gas Pipeline. The Alaska State Legislature, by passage of Senate Bill 158 in May 2001, directed the Commissioner of the Department of Revenue to prepare this report.

The analysis looks at a number of options for financial participation, ranging from outright state ownership to financing a project owned by others. It discusses the possible financial risks and rewards for each option and, where enough information is available, presents conclusions.

This report is not specific to any one proposal for commercialization of Alaska gas. Proposals include transporting North Slope gas to either Alberta, Canada, to feed into the existing North American pipeline grid for shipment to U.S. markets, or to tidewater for liquefaction and shipment of liquefied natural gas (LNG) to domestic or overseas markets.

A North Slope gas pipeline has been seriously considered since the 1970s, but to date questionable economics have always blocked its construction. The project is further complicated—or aided, depending on your perspective—by the significant amount of study, legislation, development and permitting that have already occurred or may yet need to occur in the United States and Canada.

This report uses the existing body of work on state participation in a pipeline as the starting point for its analysis. The team that produced this report included the Alaska Department of Revenue, its economic and financial consultants, and attorneys specializing in public finance and law. In addition to its own analysis, the team interviewed Alaska policymakers, oil and gas company officials, pipeline company representatives and other interested parties to obtain ideas and opinions on state participation in the project.

Key criteria used to analyze the options include the effects on the economic and financial health of the state of such a large investment, the potential for risks to the state, and whether state participation could actually help the project. Estimates of project costs, financing parameters and financial risks were used to analyze the consequences of state investment in the project and to determine the effect on the state's financial position. State funding sources were assessed in terms of legal and financial possibilities.

This report is organized into the following key sections:

**2)** Background, provides information on Alaska oil and gas development. It also discusses the state's economic and financial profile.

**3)** Alaska Gas Pipeline Overview, discusses pipeline route proposals and sponsors, and opinions expressed for and against the pipeline during interviews conducted for this report.

**4)** Ownership and Financial Participation Options and Evaluation Criteria, identifies the ownership and financing options to be considered as specified in SB 158. It also presents the evaluation criteria specified in SB 158 and identifies additional evaluation criteria considered in this report.

**5)** Evaluation of Financial Participation and Ownership Options, lists and evaluates each of the sources of state funds for a potential equity investment, financing options, and ownership alternatives.

**6)** Investment Setting, discusses the key factors affecting potential risks and returns for an investment in the Alaska Gas Pipeline, including future gas market conditions, governmental regulation, permit requirements and project costs.

**7)** Potential Returns from Pipeline Investment, evaluates the risks associated with the project and reviews potential returns associated with each of two investment options: pipeline ownership and ownership of capacity rights purchased from the pipeline owner. This section also discusses potential effects of an investment on the state's cash flow.

**8)** Effect on State of Alaska from Pipeline Investment, evaluates the effects of state ownership options on Alaska's financial position. This section looks at the state's financial integrity and creditworthiness, and its credit rating. It also discusses balancing the benefits to the state vs. the costs of a pipeline investment.

**9)** Effect of State Participation on Project Success, discusses the value of access to information that might be gained from state participation and assesses possible conflicts of interest in the state's potential dual roles as an owner and regulator. This section also looks at how state participation might help or hinder project completion and operation, and identifies how other parties participating with the state might benefit or suffer from state participation.

**10)** Conclusions and Recommendations, presents conclusions regarding state participation.

**11)** References and Acknowledgements, provides a list of the resources used in preparing this report.

SECTION 2

# Background

This section provides background information on Alaska oil and gas development and the state's finances—perspectives that are needed in considering possible state financial participation in the Alaska Gas Pipeline. The history of state participation in oil and gas projects is described first, followed by a review of the state's economic and financial profile.

## History of State Participation in Energy Projects

State investment in pipelines to transport North Slope oil and gas to market has been seriously considered many times since Atlantic Richfield Company (now part of BP) and Humble Oil and Refining Company (now ExxonMobil) announced the Prudhoe Bay discovery in February 1968. The oil companies found the largest oil and gas reservoir yet discovered on the North American continent on land leased from the State of Alaska. Initial estimates projected recovery of 9.6 billion barrels of oil and 26 trillion cubic feet (tcf) of natural gas from the reservoir.

### State Participation in Oil Pipeline Development

One year after the initial discovery, Atlantic Richfield, Humble and British Petroleum Company announced they planned to engineer, design and construct a crude oil pipeline from the North Slope to an ice-free port on Alaska's Southcentral coast. In August 1969, subsidiaries of the three companies—along with five other firms—entered into a joint venture to design and construct the Trans-Alaska Pipeline System (TAPS) from Prudhoe Bay to Valdez.

But in January 1969, just days before President Nixon was to take office, Secretary of Interior Stewart Udall issued an order freezing public lands in Alaska. This had the effect of suspending action on the right-of-way application for the oil pipeline. It wasn't long before the new Secretary of Interior, Walter Hickel, in response to questions raised during his confirmation hearings, promised he would not lift the land freeze without consulting the Senate Committee on Interior and Insular Affairs.

After several exchanges with the Senate Committee, Secretary Hickel in January 1970 modified the land freeze to open federal land for the pipeline right of way. Almost immediately, two court injunctions were issued prohibiting the proposed right-of-way grant. The Alaska Native residents of Stevens Village successfully obtained an injunction as a consequence of their claim to lands the pipeline would need to cross. The Wilderness Society obtained a separate injunction on the basis of the newly enacted National Environmental Policy Act and a claim that the proposed pipeline right of way was wider than permitted under applicable federal law.

After these two injunctions were issued in early 1970, the oil companies—along with the state, Alaska Natives and the environmental community—all turned to Congress to resolve the Alaska Native land claims and to squabble over establishing a substantial list of proposed parks, wildlife refugees and wilderness areas in Alaska.

Before the injunctions were granted—and believing that North Slope oil would soon be moving to market—the Alaska Department of Natural Resources auctioned the state's unleased North Slope acreage and received $900 million in bonus payments from the winning bidders. By the summer of 1970, however, state officials had become frustrated with the delay. Apparently, the governor and other state policymakers believed state construction and ownership of the proposed oil pipeline could provide a way around the roadblocks created by the unresolved Alaska Native land claims and the objections of the environmental community. To that end, Governor Keith Miller appointed a 15-member citizens group comprised of prominent citizens from Alaska's business and labor communities to examine the benefits of state ownership. To accomplish this mission, the Governor's Pipeline Commission, as it was called, hired the international consulting group Harbridge House Inc. to report on the feasibility of state ownership and operation of TAPS.

Harbridge House issued its report in December 1970. In its report, Harbridge concluded that state ownership would neither avoid nor resolve the Alaska Native land claims issues. Harbridge reached similar conclusions regarding the environmental community objections. In the consultant's view, state ownership would not accelerate the resolution of the problems causing the delay and private enterprise could construct the pipeline more expeditiously than state government.

Although Harbridge acknowledged that state ownership (1) could lead to lower tariffs because the state would not be subject to either state or federal income tax or municipal property taxes, and (2) could provide the state with access to information about pipeline costs and tariffs that would otherwise be unavailable, the consultants nevertheless concluded state ownership simply was not feasible. To reach this conclusion, Harbridge observed that the state lacked the experienced staff needed to manage such an enterprise and that the state would jeopardize its ability to provide necessary public services if it took on the financial and operating risks of the oil pipeline.

Finally, Harbridge expressed the view that it was unlikely the state had the financial strength needed to borrow the amount of money required to construct the project.

The Harbridge report was released just as Bill Egan succeeded Keith Miller as governor in December 1970. Possible state ownership of TAPS was reconsidered in the early months of his term and, on October 31, 1971, Governor Egan announced he had decided to proceed on a course of action leading to state ownership of the proposed pipeline. He based his decision on the potential financial benefits of state ownership outlined in the Harbridge report.

Governor Egan presented his proposal to TAPS owners, believing that state ownership would be feasible only if the oil companies supported it. The immediate response from the joint venture was negative. Nevertheless, in late 1971, the state again retained several consultants to examine the feasibility of state ownership.

The administration concluded—based upon the consultants' advice—that a state-owned pipeline was desirable and could be financed and constructed on the same schedule as a privately owned pipeline under the following conditions:

- That Alyeska Pipeline Service Company, the management company established by the TAPS owners to construct and operate the pipeline, would agree to act as the state's contractor for construction and operation of the line.

- That the major North Slope oil-producing companies would guarantee shipment of sufficient quantities of oil to generate enough tariff revenue to pay for the pipeline.
- That the major North Slope producers would guarantee completion of the pipeline.

In 1972, the Egan administration proposed legislation to implement the plan for a pipeline constructed and owned by the state. The oil companies opposed the proposed legislation, and it was not enacted.

Congress eliminated the land claims issue as a barrier to constructing an Alaska oil pipeline when it passed the Alaska Native Claims Settlement Act in December 1971. The Wilderness Society lawsuit, however, remained an obstacle. In February 1973, the U.S. Court of Appeals for the D.C. Circuit held that the Secretary of Interior lacked the authority to issue the permit for the proposed TAPS right-of-way. The state and the companies then turned to Congress for relief. Congress obliged and provided the Secretary with the necessary authority by passing the Trans-Alaska Pipeline Authorization Act in October 1973. Pipeline construction began in early 1974.

The TAPS owners then turned to the state for assistance in obtaining tax-exempt financing for the project's marine terminal at Valdez. If it could be established that the marine terminal was a public port, then financing by a public entity could be tax exempt. The oil companies requested the Alaska Industrial Development Authority to sponsor the proposed financing, but Governor Egan opposed the plan and instructed the authority not to approve it. Tax-exempt financing for the marine terminal in an amount totaling $1.265 billion ultimately was arranged through the City of Valdez. The bonds were secured solely by the security of the companies and did not involve the credit of the City of Valdez. The city obtained a 1 percent impact fee from the financing, which it placed in a permanent fund.

When oil started flowing through the pipeline in June 1977, the state initiated litigation over the tariffs for shipping oil on TAPS. Much of the state's revenue was calculated after tariffs were deducted from the value of the oil, and the pipeline tariffs had become a major point of contention between the state and the TAPS owners.

In July 1977, a representative of BP Pipelines Inc., owner of 16.6 percent of TAPS, approached the state and proposed selling its share of the pipeline to the state. BP's representative suggested that the proposal would align the state's interest with those of the other pipeline owners. BP contended that state pipeline ownership in an amount almost equivalent to its economic interest in the oil production stream (at the time a royalty interest of 12.5 percent and a production tax interest of almost 11 percent) would eliminate the need for the state to battle the companies over pipeline tariffs. The state declined to pursue the proposal, in part, because state officials believed state ownership would unacceptably increase the conflict between the state's regulatory responsibilities with respect to pipeline operation and the state's interest in maximizing public revenue.

BP's proposal to sell the state its share of the pipeline was renewed in February and March 1978 and again rejected by state policymakers.

## State Participation in Gas Pipeline Development

At the same time that state officials were considering BP's proposal to sell the state its share of the oil line, they also were considering possible state investment in a proposed pipeline to carry North Slope gas to market. Northwest Pipeline Company (now the Williams Companies) was the leader of the group of companies that in 1978 had obtained federal approval in 1978 for its proposal to build the Alaska Natural Gas Transportation System (ANGTS), a gas pipeline from the North Slope to Fairbanks and then down the Alcan Highway to mid-North America. Northwest Pipeline said it needed help from the state to finance the proposed project. The company, headquartered in Salt Lake City, operated pipelines from gas fields in the Rocky Mountains to markets in the mountain states and Pacific Northwest.

But it was almost a decade earlier, just one year after the Prudhoe Bay discovery in 1968, that Arctic Gas, a consortium of major North Slope producers with other producing and gas pipeline companies, began a series of studies on how best to move Prudhoe Bay gas to market. These studies, which started in 1969, culminated in a March 1974 application to the Federal Power Commission (FPC) for a certificate to construct a pipeline across Northern Alaska and Canada to the Mackenzie Delta and then up the Mackenzie River to Alberta and mid-North America.

Then, in September 1974, came a second proposal. El Paso Natural Gas (now El Paso Energy) filed a competing application with the FPC to construct a pipeline from the North Slope to a natural gas liquefaction plant on Prince William Sound. El Paso proposed to transport LNG by tanker from the plant to a regasification terminal to be constructed on the California coast.

A hearing before an FPC administrative law judge to consider the competing applications began in April 1975. The state participated in support of the El Paso proposal, and to buttress its support for El Paso entered into contracts for the sale of its royalty share of Prudhoe Bay gas to companies on the condition that the companies support the El Paso application pending before the FPC.

In July 1976, Alcan Pipeline Company and Northwest Pipeline formally entered the fray as a third proposal by filing an application with the FPC for its gas pipeline project that would follow the oil pipeline to Fairbanks and the Alcan Highway to mid-North America.

Shortly thereafter, in October 1976, Congress passed the Alaska Natural Gas Transportation Act (ANGTA), establishing a unique process for reaching an expedited decision on a route and sponsor for the proposed Alaska North Slope gas transportation system. This process resulted in a decision by President Jimmy Carter on September 22, 1977, selecting the Northwest Pipeline proposal (the Alaska Natural Gas Transportation System, or ANGTS). Congress ratified the President's decision, and the Canadian government made a closely coordinated, parallel set of decisions. (For details, see Regulatory History in Section 6, Investment Setting).

Questions about the state's role in financing the project arose immediately in the 1978 legislative session that followed President Carter's selection of the Northwest proposal. One critical element of the President's decision precluded any producers with significant amounts of Alaska gas from becoming equity owners in the project. The producers' only permissible role in financing and ownership of the project would be to provide guarantees for the debt.

With the deep pockets of the producers closed and the pockets of the pipeline companies shallow, it was inevitable that the state would be pressured to help. Without the producers, the total assets of all the companies that comprised the gas transportation industry were just

$26 billion—far short of what was needed to finance and build the gas project. That financial pressure was evident in President Carter's decision when he observed:

> While no … commitment has been received from the state for the Alcan project … participation by the state in the financing would be in the interest of the state, the nation and the expeditious construction of the project. (Decision, Page 119)

In February 1978, the investment banking firm Dillon, Read & Co., Inc., of New York, submitted a lengthy study to the Alaska Legislature entitled <u>State of Alaska: Alaska Royalty Gas Study</u>. The study lays out a series of options for financing a gas conditioning and transmission system for distribution of the state's royalty gas and gas liquids. The study was based on the premise that the royalty gas conditioning and transmission system would be developed on an intrastate basis and therefore not subject to federal regulation.

One of the options explored in the Dillon, Read study was an Alaska Royalty Gas Trust, allowing individual citizens to hold ownership interests in the trust. The proposal was modeled on the recently established Alberta Energy Corporation (AEC), which, at that time, was owned in part by the government of the Canadian Province of Alberta. AEC was—and still is—an oil and gas production company. It was initially capitalized in 1974 by the provincial government with an investment of $75 million. Subsequently, in 1975, Alberta publicly offered shares worth an additional $75 million. Provincial residents, however, were given a priority during the first three weeks of the offering. All of the shares were sold during the priority period, so afterward AEC had a total capitalization of $150 million, with 50 percent of the corporation owned by Alberta residents and the other 50 percent owned by the province.

The Dillon, Read firm followed up its study with a presentation to the legislature three weeks later, on March 6, 1978, focusing on options for state participation in financing the Northwest proposal and the additional potential option for citizen participation in financing the project.

During February, March and April 1978, Northwest Pipeline representatives met with executive branch and legislative leaders to explore options for state participation in the project. In February 1978, John McMillian, president of Northwest Pipeline, made a presentation to a joint hearing of the House Special Committee on Royalty Oil and Gas and the Senate Resources Committee, requesting unspecified state assistance in financing the project. Northwest followed up with a discussion memorandum on March 15, 1978, outlining options available to the state for financial participation.

On April 15, 1978, after discussions with McMillian, Governor Jay Hammond issued a statement proposing a course of action for state participation in financing the Northwest project. Such state support was necessary, he contended, or the project would be substantially delayed or abandoned. First, he proposed the state establish a pipeline financing authority through which the private companies involved could use the state to obtain $1 billion in financing through the tax-exempt bond market. The governor emphasized that this borrowing would not involve the credit of the state because the debt would be backed solely by potential revenue from the project. The governor also observed that special federal legislation would be required to make this tax-exempt financing option available, and he pledged that the state and Northwest Pipeline would jointly seek that legislation.

Second, he proposed that the legislature establish an interim committee to study whether the state should make a direct equity investment of up to 15 percent—$500 million—in the project.

In exchange for the state's support of these initial steps leading to possible state participation, McMillian agreed to 15 commitments requested by the governor covering pricing, regulation, state access to gas, community impact funds, local hire and buy, and the opportunity for state equity participation. Following up on the Hammond-McMillian statement of April 15, 1978, Northwest made presentations April 17 and April 25, 1978, to key legislators calling for a $500 million equity-related state investment in the project and a mechanism for issuing $1 billion in tax-exempt revenue bonds. Northwest disclosed in the presentations that it was seeking financial commitments totaling $4.5 billion to cover the Alaska segment of the proposed project—$3.6 billion to cover projected construction costs and an additional $900 million for contingencies.

The legislature in 1978 acted on the governor's request to establish a pipeline financing authority, the Alaska Gas Pipeline Financing Authority. This authority was authorized to issue up to $1 billion in tax-exempt revenue bonds, subject to legislative approval, for Northwest's proposed project under a detailed set of conditions that closely tracked the Hammond-McMillian commitments announced April 15, 1978.

The Legislature, through the Legislative Affairs Agency at the end of the 1978 session, commissioned an exhaustive three-volume set of studies by Arlon R. Tussing and Connie C. Barlow of the Institute of Social and Economic Research at the University of Alaska. Volume 1, dated October 25, 1978, reviewed the financial, economic, regulatory and political environment in which the North American gas industry operated. Volume 2, dated January 12, 1979, focused on the history of the proposed Northwest Pipeline project and the options available to the state to facilitate the project. Volume 3, dated April 1979, bills itself as an "[examination of] the conditions that must be fulfilled if the project is to move forward." The concluding recommendation of these studies were:

> By making known its general willingness to consider financial support for the gas transportation system, and its more specific willingness to take certain actions which do not seem to carry great risks (for example, issuing industrial development bonds), Alaska has gone just about as far as is prudent or reasonable until a believable strategy for financing the whole system is on the agenda.
>
> The most useful office Alaska could now exercise would be as a catalyst to the other parties and particularly to the federal government, in the hope that the latter will assert the kind of leadership of which no other party is capable.

As the final Tussing and Barlow conclusions suggest, Northwest had made little progress in assembling a workable financing plan for the proposed project in the year following the 1978 legislative session. Although the Legislature had created the Alaska Gas Pipeline Financing Authority, the new authority could do nothing without a comprehensive overall financing plan for the project and necessary changes in the Internal Revenue Code.

Over the ensuing three years, Northwest struggled unsuccessfully to forge a workable financing plan. During that period, Governor Hammond created first a working group and then a task force to pursue the state's interest in promoting and participating in the proposed pipeline project. The working group, appointed in August 1979, included members of the business community, mayors, cabinet officers and legislators. The task force, appointed in December 1981, consisted of cabinet officers and the governor's director of policy development.

The governor's 1981 task force commissioned another study by an investment banking firm, Kidder Peabody, to re-evaluate what the state's role should be in financing the proposed project. By March 1982, when Kidder Peabody issued its report, the projected cost of just the Alaska segment of the project had grown from the 1978 estimate of up to $4.5 billion to a new estimate of up to $30.5 billion. In addition, by 1982 the prohibition on producer-equity investment had been waived. Kidder Peabody recommended:

> … that the state participate, but that such participation be in the form of a contingent and limited guarantee of up to $3 billion of project debt.

Shortly thereafter, efforts to finance the project were abandoned as a consequence of the low gas prices that emerged with deregulation of the Lower 48 gas market.

As other options for commercializing North Slope gas have been examined in the two decades since Northwest's efforts failed, the question of how the state might participate in financing such a project has been revisited from time to time.

In 1997, in conjunction with examining the feasibility of moving Alaska North Slope gas into Asian markets as LNG, the major North Slope producers commissioned a study from JP Morgan relating to possible state financial participation. The JP Morgan study, dated October 1, 1997, listed general obligation bonds as a possible source of state funds for either equity or debt investment in a gas project, along with the Alaska Permanent Fund and perhaps public employee pension funds and the state general fund. We disagree on the feasibility of general obligation bond financing. (See Section 5 in this report.)

In contracting with JP Morgan for the study, the North Slope producers stated their objective in considering state financial participation in the proposed LNG project was to reduce the amount of their own money that would be required for the project. In addition to raising questions about how much the state could afford to invest, and what objectives should be considered in state investment, the JP Morgan study noted:

> We further believe that any investment in the project will likely need to be structured so as to avoid transferring equity-type or "enterprise" risks to the state in order to minimize the effect on the state's current credit rating.

The issue of state participation in financing a gas project was mostly dormant until the winter of 2000-2001, when high gas prices in the Lower 48 states rekindled interest in an Alaska project. State officials saw an opportunity to promote the Alaska Gas Pipeline as a secure domestic source of clean-burning natural gas for mid-America and California markets, and the major North Slope producers saw a chance to commercialize a potentially valuable resource.

The governor and legislators embarked on a series of high-profile appearances nationwide and in Canada in 2001 in an attempt to build interest—and unanimity—in the project, while the producers committed to spending up to $100 million over the next year to study the economic, environmental and engineering feasibility of building a gas pipeline. Although the producers question the economical viability of the project, based on their preliminary studies reported as of December 2001, the state is continuing to press ahead in its efforts to attract pipelines companies—if not the gas producers—to take on the project.

The former Alaska Natural Gas Transportation System (ANGTS) pipeline sponsors also again became active in the last half of 2001. This group, comprised of subsidiaries of WestCoast Energy, TransCanada, Duke, Enron, El Paso, Williams, Pacific Gas and Electric, Sempra and NiSource, announced their intent to reconstitute their partnership and revive the planning process to construct ANGTS.

## State of Alaska Financial Profile and Condition

This report addresses the question of whether the state should invest in the Alaska Gas Pipeline. Regardless of the form of state investment—equity or debt—any investment creates the risk of loss. Thus, the first question policymakers must face when deciding whether to invest in the project is whether this is an appropriate time for the state to take on additional risk.

This section provides background to help policymakers answer this question. The health and stability of Alaska's economy and state government's financial profile are two very important factors that economists and policymakers consider when determining whether taking on more risk is appropriate. Accordingly, to begin this report, we first present a brief overview of the Alaska economy and the state of state government finances.

## The Alaska Economy

Alaska's economy is based on a diverse array of sectors. No other state can boast the same mix of Native corporations, fishing, air cargo, tourism, timber, mining and oil and gas. The economy remains concentrated, however, in the twin peaks of oil at 26% of the Alaska gross state product, and government, also at 26%.[1] Alaska's economy experienced moderate growth in the 1990s. The population increased by 14 percent between 1990 and 2000, to approximately 626,932, and in 2000 Alaska per capita personal income ranked 15th in the nation.[2]

The major sectors of Alaska's economy are briefly described below:

### Oil and Gas

Alaska currently accounts for approximately 18 percent of daily U.S. oil production. As of January 1, 2000, the Department of Natural Resources estimated the state's remaining recoverable reserves at 6.4 billion barrels of oil and 33.5 trillion cubic feet of gas.

North Slope crude oil production peaked in 1988 at 2.005 million barrels per day, and by 2000 had fallen to 0.990 million barrels per day. North Slope production has been in decline since the peak, dropping an average 5.6 percent per year through 2000. However, exploration and development programs and the adoption of advanced technologies, such as three-dimensional seismic mapping, coiled tubing and directional drilling, have increased the recoverable reserves at existing fields and led to the discovery and development of new fields. The Department of Natural Resources estimates production will increase from 2002

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[1] Institute of Social and Economic Research, *Trends in Alaska's People and Economy* (October 2001).

[2] U.S. Department of Commerce, Bureau of Economic Analysis. Regional Accounts Data.

through 2007, and daily North Slope production will remain above one million barrels a day through at least 2010.

Natural gas being produced in conjunction with oil production is currently either used as fuel for North Slope operations and oil pipeline pump stations, or reinjected into the oil fields to maintain pressure.

Production from natural gas fields in the Cook Inlet Basin totals more than 200 billion cubic feet per year. This production serves the energy needs of approximately 300,000 people in the upper Cook Inlet, and has been exported as LNG to Tokyo Electric on long-term contract since 1969 and is used to manufacture ammonia and urea for export.

**Federal Expenditures**

Since the establishment of numerous military bases and posts in the 1940s, federal spending has been an integral part of Alaska's economy. Although defense spending continues to be important, more than 70 percent of the almost $6 billion in federal expenditures in Alaska were for non-defense related purposes in 2000. Salaries and wages comprised about 23 percent of the $6 billion, with the remainder coming from grant and contract awards at 55 percent, retirement and disability payments at 14 percent, and other direct payments to individuals at 8 percent. Between 1999 and 2000, federal spending increased by approximately 13 percent.[3] Alaska's total military population as of June 30, 2000, was 41,928 or nearly 7 percent of the state's population.[4]

**Fishing**

Fishing has long been an important industry in the state's economy. The National Marine Fisheries Service reports that Alaska in 1999 supplied 48 percent of the commercial seafood landings and 98 percent of the commercial salmon landings in the United States. If Alaska were an independent country, it would rank 11th in the world in the volume of seafood

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[3] U.S. Census Bureau. Consolidated Federal Funds Report for Fiscal Year 2000. "2000 State Summary Table."

[4] Alaska Department of Labor and Workforce Development, Research and Analysis Section, "Military and Dependent Population in Alaska."

harvests in 1998.[5] Although the fishing industry experienced its ups and downs during the 1990s, it averaged 4 percent of the gross state product and was responsible for 7 percent of statewide employment.[6] Unfortunately for Alaska, the strong growth in the worldwide farmed salmon industry has caused major problems for the state's natural fisheries. Low prices and oversupplies in the market are creating troubles for Alaska fishers, processors and communities.

### Mining

Between 1999 and 2000, production of minerals increased by 5 percent to $1.1 billion, in part due to the increased value of zinc. Development expenditures in 2000 increased to $137 million from $34 million the previous year. This is mostly due to expenditures at Red Dog, Greens Creek, Fort Knox and Pogo mines.

### State and Local Government

During the 1990s, state and local government accounted for 12 percent of the gross state product and 18.5 percent of Alaska's employment.[7] The Alaska Permanent Fund dividend pumps around $1.1 billion into the economy each year. The state's unrestricted general fund budget is at $2.4 billion for the fiscal year ending June 30, 2002.

### Transportation

Because of Alaska's size, isolation and dependence on natural resource exports, the transportation sector is particularly important. The percentage of private employees in the transportation sector in Alaska is twice as large as in the nation as a whole. Employment in the air transportation sector grew by 37 percent between 1990 and 1998 and accounts for more than 10,000 jobs.[8] Alaska's location—equidistant between Europe and Asia—has made it an important international hub for airfreight. Anchorage International Airport is the No. 1 airport in the United States in the amount of freight landed, with approximately 650 million

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[5] U.S. Department of Commerce, National Marine Fisheries Service, Office of Science and Technology, Fisheries Statistics and Economics Division, "Fisheries of the United States 1999." October 2000.

[6] Institute of Social and Economic Research, *Trends in Alaska's People and Economy* (October 2001).

[7] Institute of Social and Economic Research, *Trends in Alaska's People and Economy* (October 2001).

[8] Alaska Department of Labor and Workforce Development. Alaska Economic Trends, "Transportation." November 1999.

pounds of freight in Fiscal 2001. The airport is responsible for about one of every 10 jobs in Anchorage.[9]

### Tourism

Tourism has grown rapidly in the past 10 years. For example, from 1990 to 1998, summer visitors increased from 690,000 to 1,135,000. From October 1997 to September 1998, tourists spent approximately $949 million in Alaska. The tourism industry generated an annual average of slightly less than 16,000 jobs in 1998.[10]

### Outlook

Alaska Department of Labor statistics show that moderate growth of the Alaska economy has continued even in the face of the nationwide recession. Yet, as discussed below, state government has been a significant source of "new" money in the economy during the past two decades because it has pumped money derived from the oil industry and Permanent Fund dividends into the economy. As the state begins to use "recycled" money—money from taxes on residents or money from reduced dividends—the economy will necessarily contract unless a new source of new money is found. Although new money is possible through new projects, such as the Alaska Gas Pipeline, economists would not consider the economy stable because the projects on the drawing board are, at this time, too uncertain. Thus, the facts presented below indicate that during the next few years the Alaska economy may not be as robust as it has been in past 25 years.

## State Government Fiscal Profile

In examining the state's fiscal profile, three facts command overwhelming attention:

1. The state's tax base is extremely concentrated—in fact, three tax and royalty payers were responsible for more than 75 percent of the money spent from the general fund in Fiscal Year 2001.

[9] Scott Goldsmith, University of Alaska; "Anchorage International Airport: 1998 Economic Significance." September 1998.

[10] McDowell Group Inc. "Economic Impacts of Alaska's Visitor Industry 1999: Update, May 1999."

2. The state is spending more money each year than it takes in as revenue, and will soon reach the point where its readily available fiscal reserve (the Constitutional Budget Reserve Fund) will no longer be available to balance the state budget.

3. The state has $25 billion in a large savings account, the Permanent Fund, the principal of which cannot be spent but which has a very large earning capacity.

The narrowness of the state's tax base is a result of the state's reliance on its oil and gas industry to supply almost all of state income since the beginning of Prudhoe Bay production. Oil started flowing from Prudhoe in 1977, and three years later the legislature repealed Alaska's personal income tax and gross receipts business tax. Although municipalities have sales and property taxes, the state has no state sales tax or property tax, except for a property tax on oil and gas property.

Reliance on oil industry taxes and royalty payments worked very well for the state for many years, producing unprecedented budgets and even surpluses during the early '80s. In 1988, however, Prudhoe Bay production peaked, and state revenue has been in the decline ever since.

In addition to overall declining revenue, the state also experiences volatile revenue. Given the narrow tax base, the state's fiscal system is very dependent on the health of the oil industry. During the early years of North Slope production, the state enjoyed the ride of high oil prices during the late '70s and early '80s. It then felt the full brunt of the crash in 1986, when the price of Alaska North Slope crude fell from $22.25 in January 1986 to $9.72 per barrel in July 1986. State revenue fell by 42 percent due to the fall in oil prices. In response, the state reduced its workforce by 10 percent. There were almost 2,000 fewer state workers in 1987 than in 1985. The state's capital budget was reduced from $2 billion in 1985 to $343 million in 1987.

In the face of declining state revenue and the dependence on volatile oil prices, Alaska voters amended the constitution to create another reserve account in addition to the Permanent Fund—the Constitutional Budget Reserve Fund (CBRF). The state funded the CBRF with money from settlement of tax and royalty disputes with the oil companies—revenue largely owed from the boom decade of the '80s.

Although oil prices—and state revenues—recovered from the crash of 1986, the state's annual spending in the 1990s began to exceed the amount received each year as "unrestricted revenue." The decline in state revenue is not due solely to declining oil production. It's also the consequence of a provision in the state's oil and gas production tax, called the Economic Limit Factor (ELF), which lowers the tax rate on less productive fields. The idea behind the ELF is that less productive fields are more costly to operate, so a lower tax rate will keep old fields in production longer and encourage development of marginal fields. With more production, the state benefits in the long run. As the state's highly productive large fields age, however, and the ELF formula kicks in, the state is experiencing a significant reduction in oil tax revenue.

During the 1990s, the state managed to avoid deficit spending by reducing its budgets and drawing down the CBRF. The balance of the CBRF, as of January 1, 2002, was $2.65 billion. The projected budget deficit for Fiscal Year 2002—the budget gap—is $865 million; for FY 2003, it's $1.078 billion. Assuming no changes in budget or taxes, the Department of Revenue predicts the CBRF will be depleted by late summer 2004, under any reasonable oil price scenario.

A bright spot on the state's financial profile is its Permanent Fund. The 1976 constitutional amendment requires that at least 25 percent of the state's oil, gas and mining lease bonuses, rentals, royalties and federal mineral revenue sharing payments are deposited into the fund.

The fund has grown significantly over the years through its investment earnings, and as of January 1, 2002, had a market value of about $25 billion. The fund expects to earn, on average, about 5 percent per year after inflation.

According to the constitutional amendment, the legislature may spend the earnings of the fund for any public purpose, but the amendment offers no guidance on what that might be. Early in the fund's existence, the legislature established a dividend program to distribute some of the fund's earnings to the residents of the state. The annual dividend is calculated under a statutory formula that distributes approximately one-half of the actual realized earnings, and then deposits into the principal of the fund the amount necessary to "inflation proof" the principal. The 2001 dividend was $1,850 per person. Not surprisingly, the dividend program is extremely popular with Alaska residents. Any earnings left over after dividends and inflation proofing are deposited into the fund's Earnings Reserve Account, where the money is invested just as the fund's principal and its earnings are included in calculating the annual dividend. The legislature has in the past transferred significant portions of the Earnings Reserve Account into principal, but in recent years the practice has been to allow the reserve to accumulate. Although there are different ways of calculating the value of the reserve, the balance at the end of Fiscal 2002 is expected to be about $3 billion. To date, the Earnings Reserve Account has never been spent on state services.

Another bright spot is the state's low level of debt. Although Alaska did some bonding for capital projects during the early years of the pipeline, those bonds were timed to mature with the "Prudhoe Bay curve" such that as oil revenue declined, debt service payments also declined. Currently, the state has no outstanding general obligation bonds, although, as of June 30, 2001, it owed more than $70 million in certificates of participation, a type of debt used for lease/purchase of state assets.

One consequence of the low level of capital spending, however, is that the state is behind in building and maintaining many of the facilities needed by a growing state. In January 1998, the Deferred Maintenance Task Force, a group commissioned by the legislature, issued a report recommending spending $1.4 billion on schools (both major maintenance and construction), the university, highways and airports, the state ferries, harbors, buildings, American Disabilities Act requirements, and water and sewer upgrades. Although approximately $200 million of these projects have been completed, additional projects, including up to $641 million in school projects, have been identified to add to the total.

In summary, although Alaska has a reasonably strong economy, the state's fiscal profile is in flux. This is not to suggest that the state government is facing an insurmountable economic crisis—solutions to the problem do exist, and will be found. The state's fiscal situation, however, does suggest two important considerations.

First, it should be clear that state policymakers are going to have to wrestle with changes to the state's fiscal regime. They must determine whether this is the appropriate time to consider an investment in a project as large as the proposed gas pipeline. Policymakers must be aware of the time and resources that such an investment would require, and the financial risk such an investment would entail. Alaska currently does not have a long-range fiscal plan, and the state will soon need to identify new revenue sources and/or immediate budget reductions. This all must be done before the gasline would generate any revenues. The timing, therefore, is not favorable.

Second, it should also be clear that the CBRF is not a potential source of revenue for investment in the project. The state currently relies on the dwindling CBRF to help pay for needed public services each year. Due to the volatile nature of Alaska's oil and gas tax and royalty revenues, the state must retain enough money in the CBRF—unless Alaskans are willing to use the Permanent Fund for that purpose—to provide the equivalent of "overdraft protection" for years of low oil prices. Without the CBRF to protect the state during the inevitable years of low oil prices, Alaskans could face the prospect of losing essential state services, seeing their dividends cut, or taking money out of the Permanent Fund to balance state spending. Accordingly, this report does not recommend that the state invest CBRF money in the project.

SECTION 3

# Alaska Gas Pipeline Overview

Just as there were multiple proposed projects and potential developers in the 1970s, there is a similar list of possible participants and pipeline plans for the start of the 21st century. This section describes the major proposals and proponents. It is expected, however, that because of the huge scale of the project, proposals and sponsors may shift and realign over time. This section also presents information summarizing citizen and industry opinions about the advisability of state ownership.

Currently, pipelines—or pipelines in combination with liquefied natural gas (LNG) plants—are the only options being studied by the major producers and pipeline companies for bringing North Slope gas to market. An alternative that has been discussed from time to time is a process known as gas-to-liquids (GTL) conversion technology. This process converts natural gas to refined liquid petroleum products, which could be shipped to market via the TAPS oil pipeline to Valdez. However, GTL—which consumes large amounts of gas in the conversion process—is not expected to be economical for marketing North Slope natural gas in the reasonably foreseeable future.

## Proposed Pipeline Routes

There are three general pipeline routes under active consideration in 2002 by parties proposing to move North Slope gas to market. They are all shown in Figure 3-1.

1) **Alcan Highway Route.** The route follows the TAPS oil pipeline from Prudhoe Bay past Fairbanks to Delta Junction. From Delta Junction, it generally follows the Alcan Highway across eastern Alaska, the Yukon Territory and northeastern British Columbia to central Alberta. There, Alaska gas would connect with the existing North American gas pipeline system. The governor of Alaska currently favors this route, and Alaska state government is devoting significant time and money to promote it.

2) **Over-the-Top Route.** The route follows the shoreline in the shallow offshore waters of the Beaufort Sea from Prudhoe Bay 370 miles to the Mackenzie Delta in Canada's Northwest Territories. From the Mackenzie Delta, this route continues 850 miles up the Mackenzie River Valley and into northern Alberta. A pipeline following this route would move gas to the mid-North America market from both the Alaska North Slope and the Mackenzie Delta. Alaska's governor and legislature strenuously oppose this route. The legislature in 2001 passed a bill—Senate Bill 164—prohibiting rights of way for any pipeline following this route. Environmental groups and Alaska Natives living on the North Slope also strenuously oppose using this route for fear of disturbing the sensitive North Slope marine environment.

3) **All-Alaska Route.** This route parallels the oil pipeline from the North Slope to Valdez. Once at tidewater in Prince William Sound, the gas would flow into an LNG plant that would liquefy the gas so that it could be transported in specially constructed tankers to markets in East Asia or the U.S. West Coast and Mexico. Advocates of the route have submitted petition signatures to the lieutenant governor for a November 2002 statewide vote to create a government-owned corporation called the Alaska Natural Gas Development Authority to develop the state's North Slope gas resources. The initiative, if approved by voters, would direct the corporation to promote, build and operate a project using the All-Alaska Route.

Some potential project sponsors have also proposed a so-called "Y" Line that combines elements from the Alcan Highway Route and the All-Alaska Route in order to access multiple markets. Under these proposals, the sponsors would construct pipelines both down the Alcan Highway to mid-North America and to an LNG plant near Valdez. This proposed routing could provide North Slope gas to mid-North America, East Asia and the West Coast of the United States and Mexico.

Some project sponsors have also suggested the possibility of constructing spur lines to transport gas to the Southcentral Alaska distribution grid. Both the Alcan Route and the All-Alaska Route could accommodate projects that include a spur line from Fairbanks to connect with the Southcentral distribution grid in the southern Susitna Valley. The All-Alaska Route

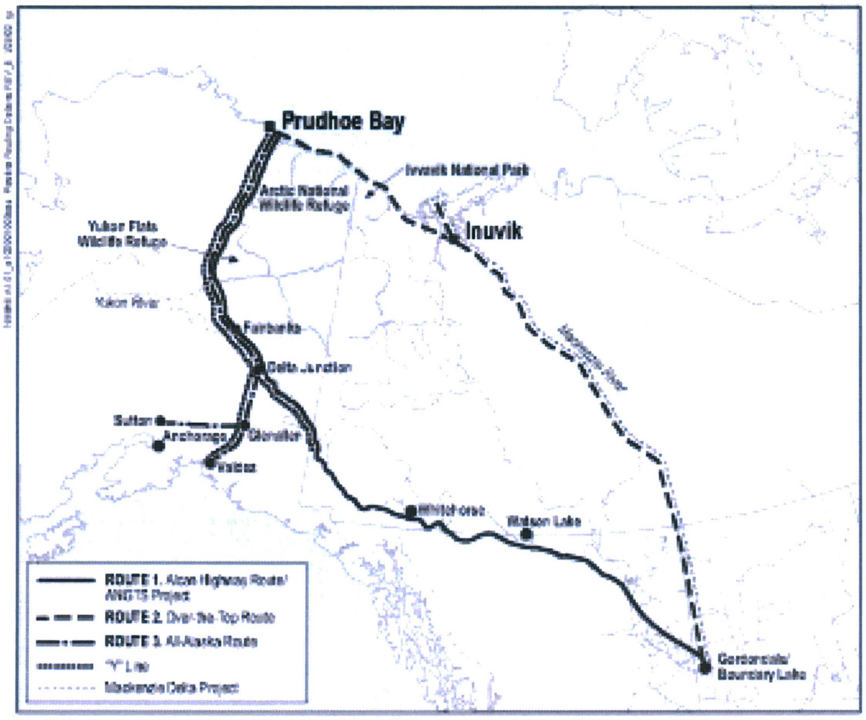


Figure 3-1
**Proposed Pipeline Routes**

would also accommodate a spur line from Glennallen to the end of the distribution grid at Sutton.

# Potential Projects

## 1) Alaska Gas Producers Pipeline Team Projects

Three major producers—ExxonMobil, BP and Phillips—hold the working interest in most of the discovered natural gas reserves on the North Slope. The discovered reserves in two units—the Prudhoe Bay and Point Thomson units—make up a large proportion of these reserves.

On several occasions since the Prudhoe Bay discovery in late 1967, these three producers, or their predecessors in interest, have considered options to commercialize North Slope natural gas. Most recently, they formed the Alaska Gas Producers Pipeline Team to study the feasibility of constructing a pipeline from the North Slope to mid-North America. They report having spent $100 million over the past year to study both the Over-the-Top Route and a pipeline following the Alcan Route. The results and conclusions from these studies are not publicly available. The following estimates have been derived from public statements made by the members of the Alaska Gas Producers Pipeline Team.

**Producers' Over-the-Top Route Proposal**

- Volume: 4.0 bcf per day from the North Slope, plus 1.5 bcf per day of Mackenzie gas.
- Project cost: $7 billion to $8 billion, not including the cost of a gas conditioning plant on the North Slope or the cost of building new take-away capacity from the project's Alberta terminal.
- Comments: Foothills has distributed a study done by one of its owners—TransCanada Pipelines—projecting a cost of $10 billion for this route.

**Producers' Alcan Highway Route Proposal**

- Volume: 4.0 bcf per day of North Slope gas.
- Project cost: $9 billion to $10 billion, not including the cost of a North Slope gas conditioning plant or the cost of building new take-away capacity from the project's Alberta terminal.

## 2) Foothills Pipe Lines Ltd.

Foothills, a Canadian gas pipeline corporation, is jointly owned by Westcoast Energy Ltd. (pending as a subsidiary of Duke Energy) and TransCanada Pipelines Ltd. It is a successor in interest to one of the original partners that sponsored the Alaska Northwest Natural Gas Transportation Co. proposal selected by the U.S and Canadian governments in 1977 to transport North Slope gas to market. TransCanada, one of Foothills' co-owners, was also one of the 16 original partners. Foothills is in the process of reconstituting the Alaska Northwest Natural Gas Transportation Co., as evidenced by memoranda of understanding that was executed in 2001 with the original ANGTS partners that had withdrawn from the 1970s' partnership. The withdrawn partners are subsidiaries of Duke, El Paso Corp., Enron, NiSource, Pacific Gas & Electric Corp., Sempra Energy and Williams Cos.

The ANGTS project jointly approved by the U.S. and Canadian governments in 1977 included a 4,800-mile international pipeline system from the North Slope to California and Midwest markets. While passing through Alaska, the pipeline would distribute gas for in-state use. The 1,700-mile northern portion of ANGTS would follow the Alcan Highway Route to central Alberta. From there, the southern portion of ANGTS (known as the "prebuild section")—a network of pipe in southern Alberta, British Columbia and across the Lower 48—would distribute Alaska and Canadian gas to U.S. markets.

The southern portion of ANGTS was completed in 1982 and currently carries Canadian gas to Lower 48 markets. The northern portion of ANGTS, as it was originally proposed, is still being pursued by Foothills and the reconstituted partnership.

**Foothills' (ANGTS) Alcan Highway Route Proposal**

- Volume: 4.0 bcf per day of North Slope gas.
- Project cost: $11.2 billion, not including the cost of a North Slope gas conditioning plant or the cost of building new take-away capacity from the project's Alberta terminal.

The ANGTS project approved in 1977 included a lateral pipeline from Canada's Mackenzie Delta along the Dempster and Klondike highways to the Alaska Highway near Whitehorse in the Yukon Territory. Foothills is not currently promoting this lateral. However, the 1977 U.S.-Canada agreement (see Regulatory History, Section 6) requires the owners of the Alcan Highway Pipeline to help pay the Dempster Lateral if Canada requests its construction. It is unknown whether the Canadian government would make such a request under today's conditions.

## 3) Alaska Gasline Port Authority

The Alaska Gasline Port Authority was formed in 1999 under the provisions of Alaska Statute 29.35 by the City of Valdez, the Fairbanks North Star Borough and the North Slope Borough. The Port Authority has proposed several different project configurations, both in terms of routes and volumes. The most recent proposal is a combination of the Alcan Highway Route and the All-Alaska Route in order to access multiple markets.

**Port Authority's Combined Alcan Highway and All-Alaska Project**

- Volume: 3.0 bcf per day of North Slope gas down the Alcan and 3.0 bcf per day of North Slope gas to an LNG plant at Valdez.
- Project cost: $18 billion for the pipelines only in Alaska (the Port Authority proposal includes no pipe beyond the Canadian border); a gas conditioning plant on the North Slope; and the liquefaction plant and LNG terminal at Valdez. The necessary pipe from the Canadian border into Alberta and beyond could add several billion dollars more to the total cost of serving the market.

## 4) Arctic Resources Company (ARC)

Arctic Resources Company is a Houston-based corporation formed in 1999 that, together with its Canadian affiliate ArctiGas Resources Ltd. Partnership, proposes to construct a pipeline using the Over-the-Top Route to transport North Slope and Mackenzie Delta gas to market. The company has announced it plans to place ownership of the project in the hands of Alaska municipalities and Canadian First Nation groups. ARC believes this ownership structure would make the project exempt from corporate income taxes in both countries. ARC favors the Over-the-Top Route for economic reasons—the company believes a pipeline using this route could bring gas to market at a lower cost. However, in a bow to Alaska politics, the company proposes using project revenue to finance development of a gas supply to Fairbanks through extraction and distribution of propane from the TAPS crude oil stream.

**ARC's Over-the-Top Project**

- Volume: 4.0 bcf per day of North Slope gas and 1.2 bcf per day of Mackenzie Delta gas.
- Project cost: $7.8 billion, not including the cost of a North Slope gas conditioning plant or the cost of building new take-away capacity from the project's Alberta terminal.

## 5) Alaska Natural Gas Development Authority

If the All-Alaska Gasline Initiative that would establish the authority passes in November, the authority will have the responsibility to promote a project using the All-Alaska Route together with a spur line from Glennallen to Sutton. The project would include a gas conditioning plant on the North Slope and an LNG plant on Prince William Sound. The authority would be responsible for arranging to finance and build the project, and for buying, transporting and marketing the gas.

## Collateral Infrastructure

With the substantial volume of new gas supply flowing to Alberta through the Alcan Route, new take-away pipeline capacity would be needed to transport gas out of Alberta and into U.S. and Canadian markets. This would be necessary because the existing pipeline capacity from Alberta is expected to be fully utilized by the time an Alaska line is completed. It is uncertain exactly how this new capacity would be added, although it likely would include capacity upgrades on existing pipelines as well as construction of new pipelines. For planning purposes, one sponsor has estimated the cost of a single new so-called "bullet" pipeline from Alberta to Chicago at $5.3 billion.

All projects would require construction of a gas conditioning plant to prepare North Slope gas for transport by pipeline. The North Slope oil producers have estimated the cost of a 4 bcf per day plant at about $2.6 billion. The Alaska Gasline Port Authority has estimated the cost of a 6 bcf per day plant at $4.2 billion.

In addition, natural gas liquids extraction facilities would be needed for each route. The North Slope oil producers estimate the cost of these facilities to be about $300 million for either the Over-the-Top or the Alcan Highway Route. The Alaska Gasline Port Authority estimates the cost at about $400 million for a plant at Valdez.

The All-Alaska Route would require investment in LNG facilities in Valdez, as well as expansion of marine shipping facilities. The Alaska Gasline Port Authority has estimated the construction cost of the LNG facility at about $4.1 billion, including a liquids extraction plant.

### Mackenzie Delta Stand-Alone Project

This project would not carry any Alaska North Slope gas. Canadian sponsors, a consortium of Canadian gas producers including Imperial Oil, ExxonMobil, Shell and Conoco, are proposing a stand-alone pipeline that would transport Mackenzie Delta gas along the Mackenzie River Valley route to the existing pipeline grid in Alberta (see Figure 3-1). In January 2002, the sponsors announced major expenditures to obtain necessary regulatory approvals to build this pipeline. Since the Over-the-Top Route would transport North Slope and Mackenzie gas, the Mackenzie Delta Project, if constructed first, could eventually become part of an Over-the-Top project.

## Citizen and Industry Views of State Participation in the Pipeline Project

State participation in the development or financing of the Alaska Gas Pipeline presents a long list of issues that must be addressed. One objective of this report is to identify as many of those concerns as possible. The Department of Revenue and its consultants interviewed 30 people, including members of the legislature and general public, as well as representatives of pipeline sponsors, to help identify these issues. Among other things, these discussions provided insights as to whether state financial participation would help or hinder the project.

Without exception, the Alaskans interviewed want to see a gasline built to create jobs in Alaska, generate tax revenues to pay for public services, and promote economic activity that would result from such a large construction project. Industry representatives were interested in seeing the gasline built for similar reasons, and also as a way to monetize the significant natural gas investments they have already made or will make in the future. However, there is one significant difference between the two groups. Although Alaskans generally believe it would be a good idea for the state to participate in the project through equity or financing, the industry group was unanimously opposed.

## Citizen Comments

Alaska is not short of natural gas, nor is it lacking in opinions on how the state should get involved in a project to bring that gas to market. In starting on this report, we interviewed 20 Alaskans for their views on whether the state should participate in owning or financing a gasline project and why, and what the state could hope to gain from its participation. The interviewees included business owners and managers, current and former legislators, retired public officials, economists, and project and environmental advocates.

The specifics were mixed but the theme was strong among a majority of those interviewed:

**1)** The pipeline probably would be a good investment for the state, in that the oil and gas industry would not go ahead with the pipeline unless it was profitable. No one said they expect glowing profits from a gasline, but most said the risk of losing money was minimal. Similarly, most of those who favor state participation said they do so not to make a profit but to help spur development of the project.

Most interviewees seemed to favor taking some money from the Permanent Fund for the state investment or borrowing the money by issuing bonds. One person suggested a mix of both options: The state could issue debt to raise cash for its investment in the project, and then the Permanent Fund could buy the state's bonds.

There was no support for state ownership of 100 percent of the project, and most referred to the state's 12.5 percent royalty stake in North Slope natural gas as a logical starting point for a possible state ownership interest in the project.

Investment is one thing, but running the company is an entirely different issue. Most stated very clearly that investing was a good idea but that taking control of the business would be a bad idea.

And, yes, most people said, Alaska is already heavily dependent on the oil and gas industry for most of its economic activity and state revenues. And, yes, state investment in a gasline would add to that dependence, but the reality is that oil and gas is the big money-maker in Alaska and, like it or not, "Alaska has and always will be a resource state." As someone said, "You put your eggs in one basket, and watch your basket."

**2)** The state should invest to protect its financial interests and control its own destiny. This category can perhaps best be described as taking steps to ensure that Alaska benefits as much as possible from the project, and to ensure that the state treasury receives all of the money it should from the sale of North Slope natural gas.

Many of the opinions centered on the value of a "seat at the table." Most people believe the state needs to have a seat at whatever table pipeline owners sit at as they discuss costs, management decisions, flows, operations, maintenance needs and whatever else partners talk about. Most of those interviewed cited years of contentious disputes between the state and the Trans-Alaska Pipeline System owners over transportation tariffs for moving crude oil from the North Slope to Valdez as something they would prefer to avoid in an Alaska Gas Pipeline. Many believe the state has not received as much tax and royalty revenue as it might have from North Slope oil because of excessive pipeline tariffs, and they are convinced a seat at the table of gasline owners would prevent a repeat of those problems. The tariffs are important because the state's royalty and production tax revenues are calculated after transportation costs are deducted from the sales price for the oil or gas.

In addition to knowing what the pipeline owners are spending and how it might affect the tariffs, many interviewees said signing on as a project partner could put the state in a better position to influence several key decisions: pipeline route, Alaska-hire provisions for construction and operation of the line, and provisions for in-state use of some of the gas. Of those who want to push for in-state spur lines and off-take provisions for local use of the gas, most acknowledged that even as a partner the state could not require any business to build or operate an unprofitable venture. They said any in-state project would have to stand on its own financial feet.

Interestingly, although there has been much interest in stripping the gas liquids to develop a petrochemical industry in Alaska, the interviewees were split on whether that made economic sense. Several were strong in their words that they did not want to see a "Petrochemical Gulch," as they called the Houston, Texas, area, developed in Alaska.

And while most everyone said they favor the Alaska Highway Route for a gasline, those same people said the major players probably would have made that decision long before the state signed on as an investor.

Regarding state involvement in control and oversight of project decisions, the group was about evenly split on whether acting as a business partner would be a conflict of interest for the state in its main role as a taxing authority, environmental and job safety regulator.

**3)** Many said state participation could help make the project more viable—simply put, moving it along so that it gets built sooner rather than later. Everyone interviewed said they would like to see an Alaska Gas Pipeline built for the money it would bring to the state treasury, for the construction jobs it would create, and for the economic boost a new industry and potentially cheaper energy would bring to Alaska. The dilemma for many was how state participation could move along the start date for construction. Certainly, state financial participation could help if the State of Alaska could find a way to lower the cost of the project, but all but a few acknowledged that would be difficult to manage.

Some thought the sheer political will of Alaska and a strong voice at partner meetings, perhaps even some delicate pushing, could get the project off the planning boards and into the groundbreaking stage. One referred to state participation as the "jump start" to the project by sending a positive signal to gas producers, pipeline companies and potential investors. However, others admitted they are skeptical that state participation as a project partner could have any immediate effect on whether the project gets built.

Some, however, cautiously warned that state involvement in the project, coupled with Alaskans' perception that natural gas would create new industries in the state, could lead state officials to push for uneconomical restrictions or side projects to the pipeline—"skew the decision making," as one person said. Or, as another said, emotions of the day can stampede government into making bad decisions. The other side said having the state participate as a partner could be a good learning experience, in that Alaskans could see from others that some dreams are unprofitable—in effect saving us from our own mistakes.

## Industry Consensus

The list of interviewees from industry included representatives of:

- ExxonMobil
- Phillips
- BP
- Anadarko
- Alberta Energy
- Duke Energy
- Williams Companies
- TransCanada
- Westcoast Energy
- El Paso Energy

The natural gas industry representatives were very aware of the economic benefits the project represented. However, they viewed the gasline as a private-industry project and not one that required or was logical for state participation. Their rationale is as follows:

- The companies believe the state does not need a "seat at the table" to ensure that it has access to the all the information it requires. The state can gather most of the information it needs regarding pre-construction activities by active participation in the Federal Energy Regulatory Commission (FERC) and Canada's National Energy Board (NEB) process. The state also would be actively involved through its own regulatory oversight process. After construction, the state would continue to have access to the information it needs through state and federal public filings and private discussions with the gasline owners.

- Several companies believe the state is not necessarily adept at making rational business judgments. The open marketplace will dictate where gas development projects can and will be developed within the state. The state, however, may want its joint-venture partners to pursue gas development projects that are politically popular, but uneconomic.

- Industry believes that if the state were a member of the joint-venture governing board, the joint-venture might not be able to move quickly enough when key decisions are needed.

And, again, the state's decisions might not be made on the basis of economics, but for political reasons. Management of any major joint venture is difficult, and industry believes that government participation at the table would only magnify these management difficulties. Given the size of the project, the financial consequences of any delay can be significant.

- Although several companies acknowledge that state participation might ease or expedite the issuance of state permits, it is not believed that the state would be useful in the federal or Canadian permit process. The companies have significant, relevant experience in handling these issues.
- Many companies thought the state might be in a natural conflict-of-interest position as both an equity holder and as a regulator. This might create tension on the joint-venture management committee because the private company members might question the motives of controversial state decisions. Some companies questioned how the state could properly balance its legal and moral obligations to its citizens with its fiduciary obligations to its joint-venture partners.
- Industry believes that if the Alaska Gas Pipeline is economically viable, the sponsors would have access to more than adequate capital from existing financial markets, likely at better terms than the state could offer. In fact, state participation might make financing more problematic due to the nature of the sources of the state's equity or debt funding and requirements the state might impose to safeguard its investment.
- Some companies believe that proponents of state ownership are motivated by the prospect of a high direct rate of return on the pipeline investment, and that this motivation would be much less if they understood that the returns would be regulated.
- Industry is of the opinion that the amount of money the state probably would be able to invest—and the amount of equity participation percentage the sponsors likely would wish to sell—would allow the state to obtain only a small, minority position restricted in terms of management participation and access to day-to-day information.

- In at least some proposed organizational structures, the same joint venture would own and operate the entire pipeline from Alaska to Canada. In that situation, it might be inappropriate or politically unfeasible for the state to own an interest in foreign assets.

More importantly, industry does not believe that state equity participation would materially advance the construction of the gasline, assist its operation or enhance its profitability. Several companies believe state participation would actually *hinder* the project. Today's situation is not at all like the early 1970s, when state participation was actively sought by many of these same proposed developers. Industry now believes it has adequate resources to ensure the success of the project without state involvement. As many companies stated, this is a private project, not a public one.

Although industry has acknowledged the state could force its way into the joint venture, it appears unlikely any of the competing sponsor groups would welcome the state's attempt to become a partner.

SECTION 4

# Ownership and Financial Participation Options and Evaluation Criteria

As noted in the Introduction, this study was mandated by passage of Senate Bill 158 in the spring of 2001. The bill is provided in Appendix A.

The legislative purpose was to obtain analysis and recommendations regarding State of Alaska options "to participate in commercial development of the state's natural gas resources through ownership of or provision of financing for a gas pipeline project." Further, the bill directs the Commissioner of Revenue to consider specific ownership and financing options and to evaluate these options according to specific criteria.

## Ownership and Financing Options

SB 158 gives five directives for this report. Three relate to ownership and financing options, and two relate to evaluation criteria. The state ownership and financing options are:

- Participate by taking an equity position in a gas pipeline project by owning all or a portion of the project, or establishing a state-owned public corporation or authority to construct and operate the project.
- Participate in financing the project, which could include issuing general obligation bonds or revenue bonds of a state-owned public corporation or authority, or in another appropriate form such as guaranteeing debt. The review should include what terms the state, or its public corporation or authority, should require as conditions for providing financial support for the project.
- Participate by establishing a private corporation that would be comprised of Alaska residents who wish to become shareholders of a new corporation that would own a portion of the project or assist in the construction and operation of the project.

In addition to these directives, the Commissioner of Revenue has given consideration to whether the state should participate in commercial development of the Alaska Gas Pipeline by purchasing capacity rights from pipeline owners.

# Evaluation Criteria

The two evaluation directives require use of the following criteria in considering the state's ownership and financing options for participation in the Alaska Gas Pipeline:

What is the effect of participation on the state's cash flow, its continuing ability to pay for essential public services, and financial integrity and creditworthiness.

Would state participation create additional risks for the completion and operation of the project; cause the project to be completed and to operate successfully; and help or hinder other parties participating with the state or its public corporation or authority in the completion and operation of the project.

Based on ideas offered by during interviews for this report, the Commissioner of Revenue added the following additional evaluation criteria:

- Whether ownership in the pipeline would provide additional information that would be helpful to the state in maximizing its royalty share of gas production or other state revenue.

- Whether there would be a conflict between (1) state ownership in the Alaska Gas Pipeline and the associated motive to maximize returns, and (2) the state's role and responsibility to regulate pipeline construction and operations

Each of the identified ownership and financing options is evaluated against these criteria in Sections 5 through 8. Conclusions are summarized in Section 10.

SECTION 5

# Evaluation of Financing and Ownership Options

The state has numerous options for financial participation in the project, including:

- Contributing capital as an equity investment for all or part of the project cost.
- Making capital available through or as a debt investment for all or a portion of the project cost.
- Guaranteeing debt.
- Making in-kind contributions.
- Combining one or more of the above options.

This section reviews and analyzes each of these options in detail and discusses the financial benefits and drawbacks to each.

## Financial Participation Options and Analysis

The source of funding is a key factor in determining whether the state should participate by taking an equity position in the Alaska Gas Pipeline. The funds must be available when needed and, of equal importance, must be legally authorized for use as such an equity investment. Use of any of the state's pools of money will have opportunity costs to the state.

The state has a variety of sources for providing capital, including using money on hand or borrowing it. Potential sources of cash include the state general fund, Constitutional Budget Reserve Fund, Permanent Fund and Earnings Reserve Account of the Permanent Fund. Sources of debt include the proceeds of general obligation or revenue bonds or certificates of participation. At a minimum, legislative authorization would be required to tap any of these funding sources and, as discussed below, some of these sources are more plausible than others.

## Timing of Capital Calls

Evaluating whether to invest a particular fund in a gasline project involves practical considerations such as the anticipated timing of the project and volatility of the cash stream from a natural gas pipeline of a project size never before constructed in this country. Regulatory approvals for the project would require a minimum of two to three years, with construction expected to take an additional two to three years. Thus, the earliest the project could be moving gas to market would be late this decade, perhaps seven years after the decision is made to go ahead with the project. The analysis in Section 7 is based on the assumption that the Alaska Gas Pipeline would be operational in 2009.

The state's cash requirements for the project would commence almost immediately and increase in size and frequency as work progresses. Initially, any investment would likely require that the state make an immediate, initial contribution to the existing partners to "buy in" to the project (we assume not on a "promoted" basis, where the state would be required to pay a premium over a pro-rata share of the actual investment). It is difficult to predict the size of this initial investment. However, assuming the project sponsors have spent $200 million before the state joins the venture, and the state were able to take a 12.5 percent equity position in the partnership, the initial equity contribution would be $25 million.

For the first few years, the joint venture's capital calls likely would be relatively small, considering the size of the project as a whole. However, once construction begins, the number and size of capital contributions would increase dramatically (ranging up to an annual contribution of nearly $300 million (2001 dollars) for a 12.5 percent stake). Further, depending upon the skill of the project's budget forecasters and the ability to minimize cost overruns, the size of ongoing funding requirements would be difficult to plan for.[11] Another concern would be whether the line started flowing on schedule—particularly if the state needed the revenue to cover the debt it had issued for its investment in the project.

The point is that in order to participate in this project, the state would be required to make significant calls upon its available funding sources and credit for a number of years before the gasline would turn a positive cash flow. Even the first year or so of the of pipeline's

[11] Another complicating factor will be whether and how the project is financed.

commercial life, which may or may not begin as forecasted, likely would not show strong or even positive cash flow due to the typical start-up issues all new pipelines face.

Thus, the source of the state's project funding would need to fit the following profile:

1) It must be immediately available.
2) It must be capable of making large capital contributions without delay and without any expectation of repayment for at least seven years, assuming the project is completed on schedule.
3) It must have the flexibility to timely meet significant and sometimes unpredictable capital calls.

It is also important for the state to keep its risk exposure to a minimum because a state government does not maintain a net worth to absorb serious losses. In this respect, it is unlike the corporate participants in the project. Losses sustained by the state would eventually have to be paid for through reduced services or higher taxes upon the citizens. Losses also could lower the state's bond rating, which would drive up the cost of borrowing for all kinds of public projects, including local schools.

## Sources of Equity Funding

As discussed below, the legislature could consider a number of existing state funds as sources of funding for an Alaska Gas Pipeline.

### The General Fund

In theory, the state could decide to appropriate unrestricted funds directly from its general fund to pay for its investment in the Alaska Gas Pipeline. Although it is ultimately a political question, there are practical problems with this approach. The general fund currently operates at a deficit and this status is not expected to change within the next few years. The state already has numerous calls on the limited money available within the general fund and it would be difficult, therefore, for the state to impose new taxes or cut public services to the extent necessary to make money available for an equity contribution to the project.

**Permanent Fund Direct Investment**

There are several ways the Permanent Fund might be able to invest in the gasline project. As a passive investor it might, under the proper conditions: (1) invest in the stock of a company or companies owning the gasline; (2) invest in the bonds used to finance the project; or (3) participate in a private equity limited partnership that finances some portion of the project. However, if the proposed investment were structured so that the Permanent Fund became actively involved in the gasline business, it lacks the legal authority to make such an investment.

The Permanent Fund, the state's major savings account, was created in 1976 by constitutional amendment. A specified portion (at least 25 percent) of the state's mineral lease rentals, royalties, bonuses and federal mineral revenue-sharing payments are dedicated to the principal of the fund.

The constitutional amendment establishing the fund placed one restriction on how the fund was to be invested: It must be invested in income-producing assets specifically designated by law as eligible for Permanent Fund investments. The legislature passed comprehensive legislation in 1980 specifying a list of permitted investments and establishing the Alaska Permanent Fund Corporation as an independent state agency to manage the fund's assets. This legislation declared the Permanent Fund to be an inviolate trust to be managed by the Board of Trustees according to a version of the Prudent Investor Rule often referred to as the Prudent Expert Rule.[12]

The legal list governing permitted investments has been amended several times, and allowable investments include mortgages, real estate investments, certificates of deposit, term deposits or bankers' acceptances, and interests in domestic and non-domestic companies.[13] There are other limitations, too. This statutory list also places a 5 percent limit

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12 The Prudent Investor Rule as applied to investments of the fund means that in making investments the board of trustees shall "exercise the judgement and care under the circumstances then prevailing that an institutional investor of ordinary prudence, discretion, and intelligence exercises in the management of large investments entrusted to it not in regard to speculation but in regard to he permanent disposition of funds, considering probable safety of capital as well as probable income." AS 37.13 120 (a).

13 AS 37.13.120

on the amount of voting stock the fund may own of a single corporation. And, domestic stocks owned by the fund, with some exceptions, must be listed at the date of purchase on an exchange registered with the federal Securities and Exchange Commission.[14]

Another requirement in statute is that the board must favor in-state investments if the risk and return are equal to the alternative investment opportunities.[15]

The legislature also adopted a 5 percent "basket clause," which allows the trustees to invest up to 5 percent of the fund's total assets in "other types of investments not specifically listed," so long as the Prudent Expert Rule is satisfied.[16]

Considering all of the above limitations in statute, could the state use the investment authority of the Permanent Fund to go into the gas pipeline business as a partial or 100 percent owner of the project? Without a change in the laws governing the investment authority of the Permanent Fund, the answer is "no." Although the Permanent Fund currently lacks the authority to invest as an active participant in a North Slope gasline business, the legislature could amend the statute and specifically direct the Permanent Fund to make such an investment.

It would be different, however, if the Permanent Fund were simply buying stock or investing in bonds issued by a corporation or corporations that own the gasline. The Prudent Expert Rule requires the trustees to weigh risk and reward and consider investments within the context of the fund's overall asset allocation, while avoiding the concentration of investments in single entities. To comply with the rule, the trustees follow a detailed decision-making process that includes adopting an annual asset-allocation policy and selecting specialized managers to achieve a balanced, diversified portfolio. Under the available investment authority and the constraints of the Prudent Expert Rule, the trustees might well be able to make limited investments in either the equity or the debt of a North Slope gasline enterprise.

Finally, legal question exists as to whether a gas pipeline project that would not produce income for a period of years would qualify as an income-producing investment under the law

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[14] AS 37.13.120(l)

[15] AS 37.13.120(l)

[16] AS 37.13.120 (k) (1).

and whether the constitutional limitation would permit such an investment. We understand that the trustees believe this specific limitation would not preclude this kind of equity investment in a gasline project, but there is no specific legal ruling on the income-producing issue.

**Earnings Reserve Account of the Permanent Fund**

If the legislature decided it would be in the Alaska's best interests for the state or an independent state corporation to enter the North Slope gasline business, it could appropriate money from the Permanent Fund's Earnings Reserve Account (ERA) to a state agency for that purpose.

Income earned on Permanent Fund investments is credited to the ERA and, on June 30 each year, appropriations are made from the ERA first for dividends to residents of the state and then for inflation proofing of the Permanent Fund's principal. Any undistributed income remaining in the ERA is available to cover future dividend or inflation-proofing needs. The legislature also may appropriate money from the Earnings Reserve Account at any time for any purpose. To date, however, it has never appropriated the money for anything other than dividends, inflation proofing or to increase the principal of the fund.

The Department of Revenue anticipates that the amount of surplus earnings available from the Permanent Fund each year over the next decade will average about $250 million. However, the actual amount available in any one year will vary enormously—ranging from $0 to more than $500 million, depending on the performance of the financial markets and the mechanics of how the surplus is determined.

However, one must remember that the only vehicle the Permanent Fund has to absorb volatility in its investment income is the ERA. Committing the Earnings Reserve to the gas project might jeopardize the Permanent Fund's ability to pay dividends and inflation proofing. And, considering Alaska's general fund deficits, bond rating agencies might view such a commitment unfavorably.

In summary, appropriations from the ERA could be a source of funding for the project. This course of action, however, presents a number of obvious economic and political risks.

Actual and projected Permanent Fund principal and Earnings Reserve Account balances are shown in Figures 5-1 to 5-3, as are the month-to-month fluctuations in the ERA balance.

**Figure 5-1**

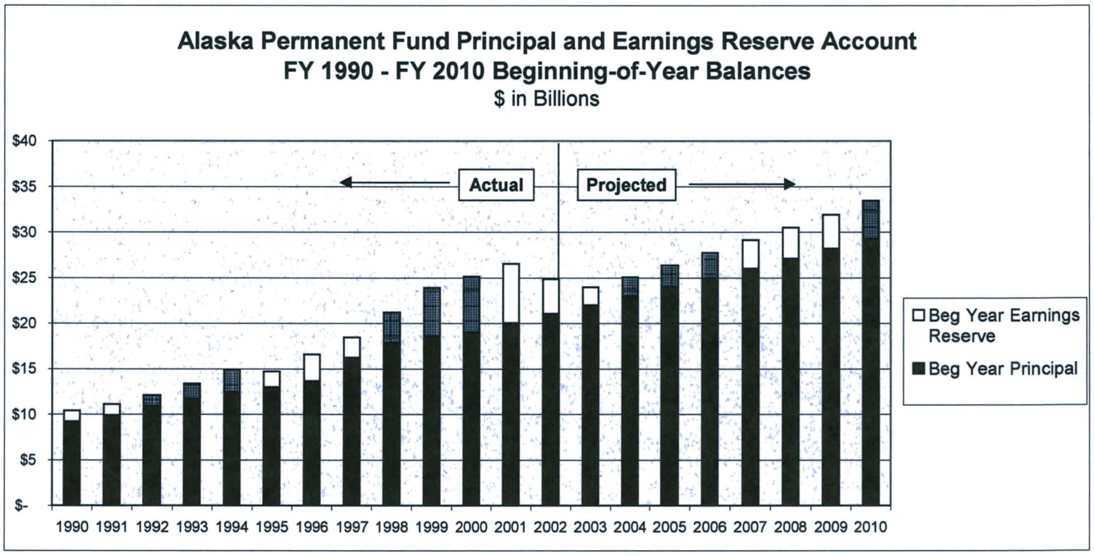



**Figure 5-2**

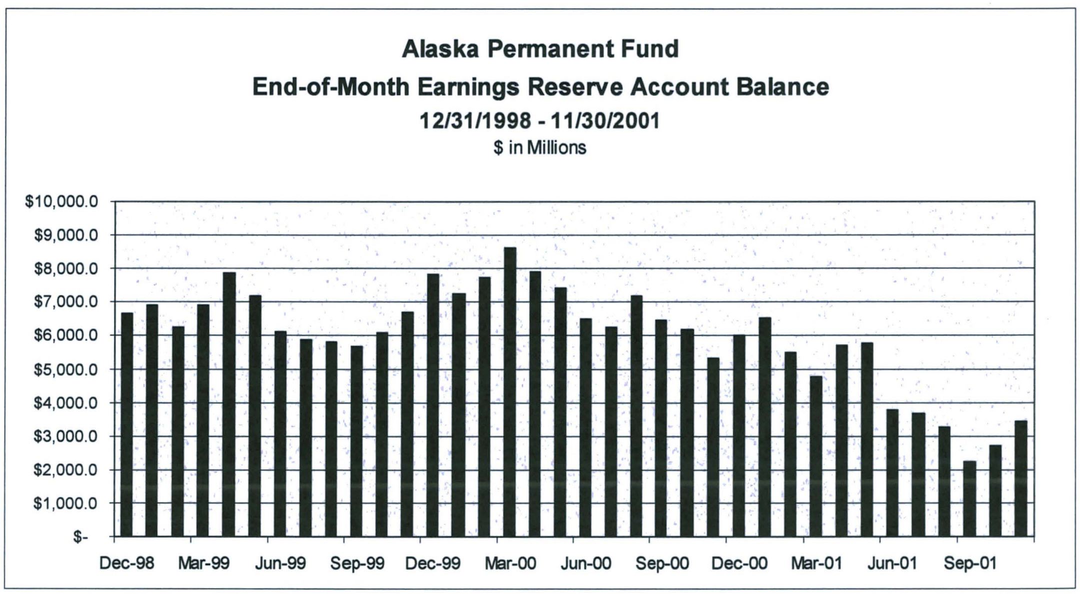
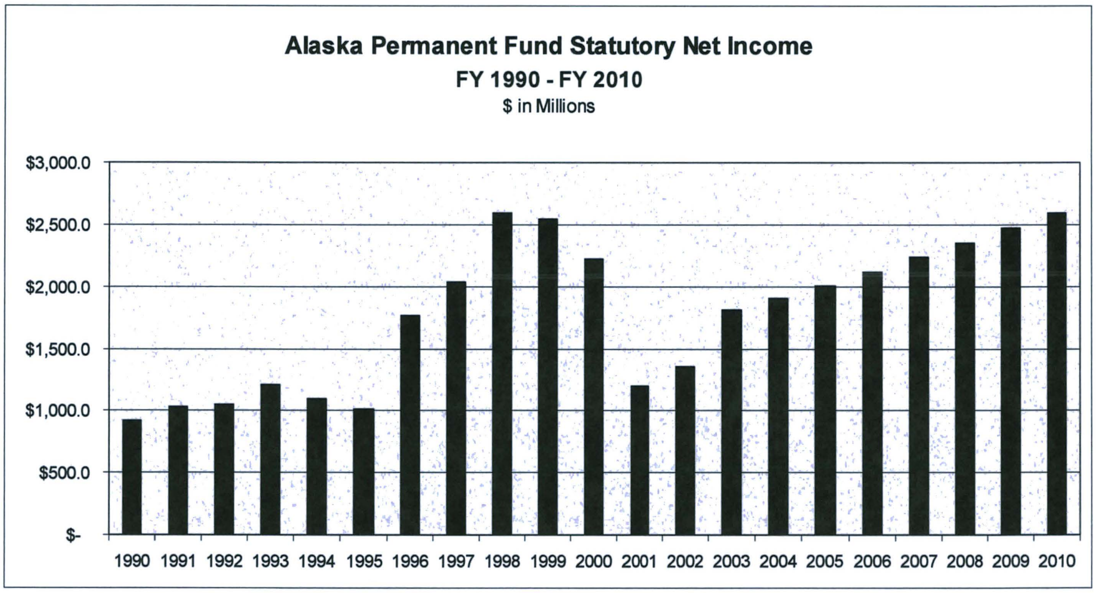


**Figure 5-3**

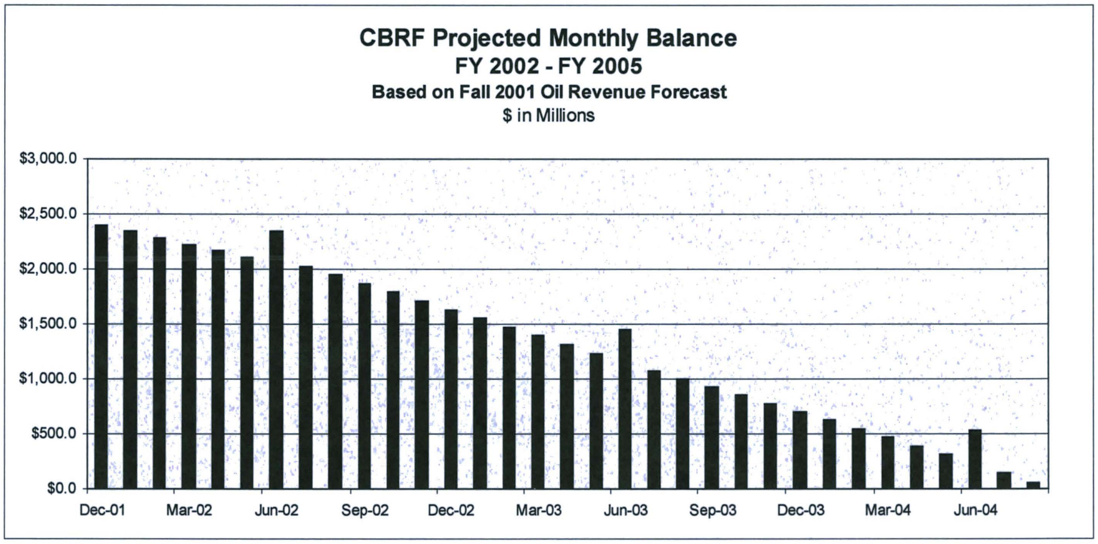



## Constitutional Budget Reserve Fund

Created by the voters in 1990, the Constitutional Budget Reserve Fund (CBRF) holds the proceeds from settlements of oil and gas tax and royalty disputes since July 1, 1990. It generally requires a three-quarters majority vote of each chamber of the legislature to withdraw money from the account. For all but two years since 1991, the state has relied on the CBRF to fill the difference between unrestricted general purpose revenue and the annual state budget. Over the past 10 years the state has deposited about $5.5 billion into the CBRF, earned about $1.5 billion from investments, and withdrawn more than $4.3 billion to pay for public services—leaving a balance of $2.65 billion on January 1, 2002.

The projected declining balance of the CBRF is illustrated in Figure 5-4.

**Figure 5-4**




Note: The $300 million peaks in June are caused by repayment of the beginning year draw.

A fundamental problem with using the CBRF as a potential source for equity investment in the project is that the Department of Revenue forecasts the CBRF is likely to be depleted by late summer 2004 due to declines in unrestricted general fund revenue.

Given the uncertainty of any remaining balance in the CBRF after Fiscal 2004, and the potential negative reaction by bond rating agencies to using this fund for purposes other than covering annual general fund deficits, the CBRF is not a viable source of equity funding for the project.

### In-Kind Contributions

Some have suggested that another source of equity for state investment in the Alaska Gas Pipeline could be in-kind contributions from income-generating items like right-of-way lease payments or advance sales of state royalty income. Even if the state was willing to forego the steady revenue benefit of such income, there is a significant problem with the in-kind concept. Using these funds this way likely would violate the dedicated-funds prohibition in

Alaska's Constitution.[17] As a result of this constitutional limitation, the proceeds of state taxes and licenses generally are prohibited from being deposited anywhere but the general fund and the Permanent Fund.[18] If the legislature wished to pursue this alternative further, review by the Attorney General's office would be appropriate.

In any event, with respect to right-of-way lease payments only, it is not expected that the payments would produce enough income to support a "trade" for equity. Although approximately 700 miles of the Alaska Highway Route would be in Alaska and the majority of the route would cross state lands, the state's earnings from right-of-way lease payments would be modest. In Fiscal 2001, for example, the state received only $730,000 from lease rental payments for the 800-mile Trans-Alaska Pipeline System. Annual lease payments from the gasline likely would be similar.

## Sources of State Debt Funding

Although an outright appropriation from one of the above sources of state funds does not appear practicable, it is possible the state could structure some type of bond issuance to obtain funds for an investment in the project. The different bonding alternatives are discussed below. The intricacies of coordinating private debt obtained by project sponsors and public debt of the state would be complex and would require further analysis after the gasline funding plan is known. It should be noted, however, that the state would face formidable legal and practical hurdles to financing a significant portion of the project with tax-exempt debt.

There are several types of debt that could be issued, depending on the state's level of commitment. Debt instruments include general obligation bonds, lease-purchase obligations and revenue bonds (with or without state "moral obligation" guarantee). State-guaranteed

[17] "DEDICATED FUNDS. The proceeds of any state tax or license shall not be dedicated to any special purpose, except as provided in section 15 of this article [establishing the Permanent Fund] or when required by the federal government for state participation in federal programs. This provision shall not prohibit the continuance of any dedication for special purposes existing upon the date of ratification of this section by the people of Alaska." Alaska Const. art. IX, Sec 7.

[18] Lengthy discussions of the dedicated funds prohibition in the context of natural resources revenues, including royalties and bonuses, are found at 1982 Alaska Op. Atty. Gen 13 (November 30, 1982) and 1975 Alaska Op. Atty. Gen (May 2, 1975). Presently, right-of-way revenue is deposited to the general fund. Of royalty and bonus income, 25 percent is allocated to the Permanent Fund, 0.5 percent to the state school fund, and the remainder to the general fund.

bonds are not considered feasible because they would require an amendment to the Alaska Constitution.[19]

The combination of state debt (e.g., general obligation bonds and revenue anticipation notes) and state-supported debt (a portion of University of Alaska debt, lease-purchase financings, and a share of municipal general obligation bonds for school construction) are the measure of Alaska's debt burden used by Moody's, Standard & Poor's and Fitch in assigning a credit rating to state debt obligations. As discussed below, the state's current bonding ability is limited unless the state is willing to accept lower credit ratings.

Today the state maintains favorable credit ratings for its various debt instruments. Its most recent credit ratings were Aa2 by Moody's, AA by Standard & Poor's and AA by Fitch, which are in the high end of debt rating scheduled. However, all general obligation bonds of the state have since been retired (the last in Fiscal 1999). The state's debt rating history is set forth in Table 5-1.

**TABLE 5-1**
State of Alaska Credit Rating History
*(ratings as of date shown)*

| **Moody's Investor Services** | | **Standard and Poor's** | | **Fitch Investor Services** | |
|---|---|---|---|---|---|
| July 13, 1961 | Baa | June 4, 1971 | A | May 3, 1994 | AA |
| September 12, 1969 | Baa1 | January 23, 1975 | A+ | | |
| August 29, 1974 | A1 | June 14, 1980 | AA- | | |
| June 13, 1980 | Aa | August 5, 1992 forward* | AA | | |
| November 26, 1998 forward | Aa2 | | | | |

* Standard and Poor's has withdrawn its rating of the State of Alaska, as all general obligation debt of the state has been repaid. The state expects to obtain ratings from the three rating agencies in 2002.

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19 Alaska Const. art. IX, sec. 8. The voters did, however, amend the constitution in 1982 to permit the state guarantee of housing loans for veterans issued by the Alaska Housing and Finance Corporation.

### General Obligation Bonds

The legislature could authorize the issuance of general obligation bonds to fund a state contribution to the Alaska Gas Pipeline. General obligation bonds, as debts of the state, are backed by the state's full faith and credit. General obligation bonds are the most secure of debt instruments and, therefore, bear the lowest rate of interest. However, general obligation bonds must be ratified by the voters and approved by the State Bond Committee.[20] The state has no general obligation bonds outstanding today (the last were paid off in 1999).

The state has issued general obligation bonds 49 times since statehood, raising almost $1.4 billion. Although there is no statutory limit on the amount of such bonds, the size of a general obligation bond issuance to support this project could be the largest in state history. The largest to date was $200 million issued in 1982. We estimate that a 12.5 percent share of the Alaska Gas Pipeline could require an investment in the range of $1.5 billion, unless project financing is available.

There are legal issues and at least one practical issue associated with the issuance of such bonds in support of an investment in the project. First, the state is precluded constitutionally from lending its credit directly to benefit a private entity.[21] The proceeds of general obligation bonds, thus, could be available to purchase a state equity investment in a pipeline (assuming appropriate statutory declaration of public purpose). The proceeds of such bonds, however, could not be used to make a loan to private investors.

Second, the issuance of general obligation debt to make an equity investment in a joint venture appears to be unconstitutional. The Alaska Constitution states that such bonds may only issued for capital improvements.[22] Issuance of debt to support an investment in a joint venture that would own a natural gas pipeline would not be a permitted use of general obligation bond proceeds because it would not be a capital improvement for public use, but rather an investment in an ownership entity. The proceeds of any general obligation bond issue, therefore, would need to be used solely to acquire an undivided interest in an asset, the

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20 Alaska Const. art. IX, sec. 8; A.S. 37.15.

21 Alaska Const. art. IX, sec. 9.

22 Alaska Const. art. IX, sec 9.

pipeline. This may not be a practical method of structuring the relationship of the other parties participating in the project.

Third, the state's borrowing capacity may be too insignificant to be of any practical assistance to support the investment. The state's borrowing capacity can be measured using generally accepted ratios (as discussed in Section 8 of this report). These ratios represent acceptable norms for issuing debt. It has been state policy to stay within the range of committing 8 percent of unrestricted general fund revenue to debt service, in order to maintain the state's historical AA credit rating. [23] At a limit of 8 percent of the general fund's unrestricted revenue, the state's available maximum general obligation bond capacity ranges from about $210 million of 10-year bonds to approximately $300 million in 15-year bonds.

However, investors have recognized the shift over time from when most state revenues were unrestricted to today, when a significant portion of revenues are restricted by the state's direction. That is, the state has segregated money into various funds that create restricted revenues rather than unrestricted—the largest of which is the Permanent Fund. If we add Permanent Fund earnings (after inflation proofing) to the state's unrestricted revenue and take 8 percent of that, the state's available debt capacity would jump dramatically—about $1.2 billion of 10-year bonds to $1.7 billion in 15-year bonds.

Nevertheless, any new issuance of state debt (especially if it relies on restricted revenues for debt capacity purposes) would be carefully reviewed by the rating agencies due to the state's uncertain fiscal situation. A proposal by the state to exceed its current debt service thresholds would need to be carefully reviewed for presentation to the rating agencies in order to avoid a downgrade.

**State-Supported Debt**

State-supported debt is debt for which the ultimate source of payment is, or may include, appropriations from the state general fund. The state's full faith and credit is not pledged

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[23] Debt service, for determining debt capacity, includes debt service on general obligation bonds, University of Alaska bonds that are state supported, state reimbursement of municipal school debt, and lease payments on lease purchase financing.

[24] Since 1996, the largest taxable general obligation bond issuance was by the City of New York for general purposes and public improvements in the principal amount of $434.1 million. Source: Thomson Financial.

against the debt, and state-supported debt is not considered state-guaranteed debt for purposes of the Alaska Constitution because the state's payments on the debt, even if the subject of a contractual commitment, are contingent on annual legislative appropriation. As a result, citizen approval of such debt is not required—although legislative approval is required in almost all instances.

The form of state-supported debt that might be useful in this project is lease-purchase financing obligations consisting of certificates of participation (COPs) issued by lessors of facilities used by the state. In such situations, generally the debt is secured by the lease payments on the leased facilities.

The limitations inherent in this type of financing are similar to those associated with general obligation bonds, except that no public vote is necessary. This debt also would not be tax-exempt, and the state has limited capacity without jeopardizing its credit rating. Further, the complexity inherent in structuring a financing of this magnitude as a lease is substantial. The state probably would lack sufficient debt capacity to lease the entirety of the pipeline to the project sponsors.

**Revenue Bonds**

Probably the more likely source of debt financing would be through the issuance of some form of revenue bonds. These most probably would take the form of bonds issued by a state agency and secured by revenues generated from the use of the pipeline, such as ship-or-pay contracts for moving gas through the line. In the most customary form of revenue bonds, the project and its revenues constitute the sole source of repayment of the revenue bonds. Private corporate guarantees and letters of credit also could provide additional security.

In a separate type of revenue bond, additional security would be obtained from a reserve fund that includes a discretionary capital reserve provision. A typical capital reserve fund is approximately equal in size to the maximum amount of debt service required in any year. If the reserve fund falls below its required level and if a moral obligation concept were applied, the legislature may, but is not legally required to, appropriate funds sufficient to restore the capital reserve fund (in other words, the state has a "moral obligation"). The authority to issue moral obligation revenue bonds is contained in the enabling legislation of several state agencies such as the Alaska Energy Authority and the Alaska Industrial Development and Export Authority.

The revenue bond concept is not new to this project. Authority for revenue bonds was approved for the Alaska Pipeline Financing Authority in 1978. In its enabling legislation, the Financing Authority was authorized as a conduit to issue revenue bonds up to the principal amount of $1 billion, inclusive of amounts required for capital reserves, for the purpose of purchasing or otherwise acquiring any obligation issued with respect to the ANGTS project—provided that the payment on that obligation was fixed and certain as to terms of repayment. Debt service on the bonds was to be paid from the income and receipts derived from the project. The bonds were expressly not debt of the state or any political subdivision, and were to be paid exclusively from the project income. The state pledged that it would not limit or alter the rights and powers vested in the Financing Authority to fulfill the terms of any contract made with the bondholders or in any way impair the rights and remedies of those holders unless the bonds were fully paid and discharged.[25]

Revenue bonds are not a general obligation of the state, nor does the state provide security for the debt in any other manner except in the case of "moral obligation" pledges. Depending upon the other available security, a "moral obligation" could provide additional credit enhancement and lower interest rates to traditional revenue bonds.

### Alaska Gasline Port Authority Financing Proposal

As described in Section 3, the Alaska Gasline Port Authority has proposed an innovative plan to finance a pipeline from the North Slope and an LNG facility at Valdez, along with an additional line branching away at Delta Junction to carry natural gas to the Canadian border to connect with the Lower 48 grid. The Port Authority proposes to finance 100 percent of the costs with a combination of tax-exempt and taxable revenue bonds. Based upon legal and financial analysis and an IRS letter, the authority believes its *income* would be tax-exempt.[26] Since the letter application to the Internal Revenue Service is not available, it is not clear whether the ruling is based upon all of the relevant facts.

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[25] AS 44.82.150, repealed 1994.

[26] Private Ruling 200017018 (January 27, 2000).

First, according to the IRS response, the Port Authority represented that the authority's revenues would be derived primarily from the sale of natural gas to municipalities within the state and to other purchasers expected to include governmental and private enterprises. But the vast majority of the authority's revenues would, in fact, be derived from sales of natural gas outside the state.

If the underlying facts have not been fully or accurately described in the letter to the IRS, the IRS is not bound by the ruling and it may not be relied upon.

Second, there may be an issue regarding the fact that the Alaska Constitution does not specifically authorize port authorities to exist as political subdivisions of the state, and only the state or a political subdivision may issue tax-exempt bonds.

It is generally more expensive to borrow money without any equity commitment because 100 percent debt financing—the absence of any owner contribution whatsoever, such as buying a house with no down payment or other collateral—increases the risk to creditors of not recovering the entire debt. Thus, 100 percent debt financing for the project, if it is available at all, could come at a relatively high cost. This high financing cost could negate all or a portion of the relatively limited benefits attributable to the port authority structure.

The Port Authority claims that it would be exempt from federal income taxes for the amount of income it retained for itself (estimated by the Port Authority at $37 million per year) and the amount it remitted to the state and other municipalities (estimated at $333 million per year). This income would come from the "profit" earned by the Port Authority on the difference between what it paid the producers for the gas and what it was able to earn by selling the gas and LNG on the world market. This income tax savings could be seen as a benefit to the project. The foregone tax would be about $130 million per year, according to Department of Revenue estimates.

A few comments on the practical considerations of the Port Authority plan also should be made. The Department of Revenue and its consultants are unaware of any LNG terminal facility, gasification facility or natural gas pipeline in the world that has obtained 100 percent debt financing. LNG facilities with up to 75 percent debt have been constructed, but they are the exception—something in the range of 60 percent to 70 percent is more common. The hurdles to obtain even this level of financing is high, with lenders generally requiring the following to be in place just for a "conventional" project financing of a LNG terminal:

- A long-term LNG sales agreement with creditworthy purchasers for a minimum base load.
- Long-term natural gas supply agreements with creditworthy suppliers for a minimum volume.
- Acceptable quality and quantity of proven gas reserves.
- Liquefaction capacity sufficient to meet the project's sales obligations.
- Fixed-price or minimal determinable price contracts.
- Long-term transportation agreements with sufficient capacity to meet delivery schedules.
- Capped marine freight price.
- An experienced shipbuilder if transportation is via a new tanker.
- Experienced vessel owners and operators.
- Proven technology.
- Fixed-price, date-certain engineering, procurement and construction contracts with experienced, creditworthy contractors.
- An appropriate framework among creditors to harmonize force majeure provisions and other potential contractual issues.
- A cash-flow allocation to allow each project access to appropriate payment stream.
- Adequate payment security mechanisms such as escrow accounts and letters of credit.

The prerequisites for financing a natural gas pipeline are similar. Some of the requirements listed above for an LNG facility can be met by the Port Authority, but it still faces formidable challenges to satisfy others. For example, obtaining gas supply commitments from North Slope producers and suitable off-take agreements from purchasers seems unlikely for a variety of reasons, including:

- Their lack of interest in LNG exports from Alaska.
- Their involvement with gasline proposals they believe are more commercially viable than LNG.
- The question of what happens when the Port Authority gasline gets to the Canadian border.
- Their concerns about doing business with an entity controlled by municipalities.

## Other Financial Participation by the State

### State Loans to Project Sponsors

If funds are available, loaning money to the project may be a more desirable alternative for Alaska than equity participation due to a stronger claim on revenues, lower construction and operation risks, and fewer conflicts of policy interests. There are practical limitations on the state's participation, however.

- First, Alaska would need to have funds available to lend to the project. The source of such funds may affect the ability of the state to meet other governmental needs.
- Second, any financial return to the state would be delayed at least until after 2010.
- Third, the debt structure easily could put the state in a minority or subordinate position with little control over the project or its operation.
- Finally, and most importantly, the state's debt likely is not needed by the project developers.

During the interviews, the potential project developers generally indicated they only would have an interest in state financial participation if the state could somehow issue tax-exempt securities. As discussed above, this alternative would probably require an exception to federal tax law. Most of the potential project developers have credit ratings and overall financial resources equal to or more substantial than that of the state (Table 5-2). They likely would be able to obtain attractive interest rates and terms and, accordingly, state taxable debt is not particularly attractive as an alternative. As shown in the following chart describing common credit measurement factors as of January 15, 2002, the creditworthiness of the potential gasline project sponsors is good to excellent. Further, even though this project is of enormous magnitude, there appears to be adequate debt capacity in world capital markets today to fund it.

**TABLE 5-2**

Corporate Debt Rating of Potential Project Developers

| Company | Senior Debt (SP/Moody) | Debt + Pfd / Bk Cap | Fixed Charge Coverage | Debt + Pfd / EBITDX | Debt + Pfd / DsCF |
|---|---|---|---|---|---|
| ExxonMobil | AAA/Aaa | 15% | 92.6 | 0.3 | 0.4 |
| BP | AA+/Aa1 | 24% | N/A | 1.5 | 2.4 |
| Phillips | BBB+/A3 | 47% | 14.1 | 0.9 | 1.4 |
| Duke | A+/A1 | 49% | 7.3 | 2.9 | 5.2 |
| TransCanada | A-/A2 | 72% | 2.3 | 5.1 | 9.2 |
| WestCoast | A-/ n/a | 72% | 2.6 | 7.0 | 11.3 |
| El Paso | BBB+/Baa2 | 58% | 3.9 | 3.5 | 3.9 |
| Williams | BBB+/Baa2 | 55% | 2.3 | 3.5 | 9.3 |

EBITDX = Earnings before Interest, Taxes, DD&A, and Exploration Exp.

DsCF = Discretionary Cash Flow = Net Income + DD&A + Def. Taxes + Exploration Exp. + Other Non-Cash Items

Debt + Pfd / Bk Cap = (Total Debt + Preferrred Stock) / Total Book Capitalization

Fixed Charge Coverage = EBITDX / (Interest Expense + Pre-Tax Preferred Dividend)

## Direct Guarantees

Even though the creditworthiness of the known project sponsors is high, if there is a shortfall in that respect perhaps the companies might have an interest in the state lending credit support through forms of state guarantees. Generally, the use of a guarantee would be of significant benefit only if the guarantor has a credit rating higher than the rating on any debt issued by the pipeline investors—which does not appear to be the case with the state.

In contrast to direct funding through an equity investment or debt, debt support would not require the outlay of state funds. The guarantee could be provided by either (a) the state directly guaranteeing debt issued by the sponsors, (b) a state authority guaranteeing debt issued by the sponsors, or (c) the state guaranteeing debt issued by the authority, the proceeds of which would then be lent to the sponsors. The state's obligation, in all cases, would be limited and contingent upon various events as the state could negotiate, such as expiration date, subordination rights, amount, guarantee payment terms, equity conversion rights, etc.

The structures referred to in (a) and (b), however, may require voter action. Further, the Alaska Constitution prohibits the state from directly guaranteeing private debt.[27,28]

Assuming the two hurdles mentioned above could be overcome, there are various forms that an appropriate state guarantee could take. A direct, full-faith and credit guarantee by the state obviously would constitute the strongest credit support the state could make, but this also would be the riskiest for the state. There is the possibility that a guarantee could be structured in a form that is constitutionally permissible. The legislature may be able to set aside a specific category of reserve funds within the general fund or Earnings Reserve Account of the Permanent Fund, for example, upon which to base a limited guarantee. However, this would require further analysis of the Attorney General and, even if legally permissible, would be removing flexibility to meet future fiscal requirements of the state.

**Moral Obligation Guarantees**

The state may also be able to lend its credit support through pledging its moral obligation in some form of financing structure. Such a moral obligation would not constitute the legal indebtedness of the state and would not, therefore, require action by the voters. Such a structure has won credibility with investors in other contexts where it has been employed because of the perception of rating agencies and investors that the state undertaking such a moral obligation would, if necessary, honor its moral obligation by appropriating funds to meet debt service shortfalls. The failure to do so would be regarded as a derogation of the state's credit and hurt the state's ability to sell its securities.

The moral obligation commitment could be strengthened by earmarking a single revenue source as security for the moral undertaking. Such a structure would involve the legislature appropriating existing revenue to a state authority and then enacting legislation to appropriate

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[27] Alaska Const. art. IX, sec. 8.

[28] In 1982 the voters approved a constitutional amendment that permits the state to guarantee unconditionally as a general obligation of the state the payment of principal and interest on revenue bonds issued by the Alaska Housing Finance

a revenue stream to the authority in future years, subject to the right of future legislatures to reverse such appropriation. Because the legislature is not legally required to appropriate such revenues in any year, such action should not constitute a legal dedication of revenues in contravention of the constitutional prohibition previously discussed. The authority would, in turn, issue debt secured by a pledge by the authority of such revenues and then lend the debt proceeds to the project sponsors. The revenue stream so pledged would not be utilized to pay debt service unless the sponsors defaulted on the loan agreement and, to the extent not utilized for debt payments, the revenue stream would be available in any year for any other purpose designated by the legislature.

### Compensation to Alaska for Loan Guarantees

In the event that Alaska decides to extend a limited and contingent guarantee, the state would be entitled to compensation for its undertaking. There are a number of ways such ways such values could be determined in an arms-length negotiation with the sponsors. However, these alternatives are beyond the scope of this report.

## Tax Issues

Under existing federal tax law, states may issue tax-exempt municipal bonds for public projects, such as schools. Without an exception to the existing Internal Revenue Code, however, bonds—whether general obligation, revenue or other type—issued to finance a project such as the Alaska Gas Pipeline are likely to be almost all taxable. This debt would be considered "private-activity bonds," and the interest on private-activity bonds, except for those that finance certain exempt facilities and nonprofit enterprises, is taxable.

Debt is classified as a private-activity if it meets certain tests, established under the regulations promulgated under Section 141 of the Internal Revenue Code. The debt must meet both the private-use and private-payments tests. In addition, if the debt proceeds are deemed to have been used to make "private loans," the debt is considered to be private-activity bonds.

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Corporation for the purpose of purchasing mortgage loans made for residences of qualifying veterans. This is the only purpose for which state-guaranteed bonds may be issued.

Certain categories of facilities, however, may be eligible for tax-exempt financing. It is possible, though not certain, that certain aspects of this project could qualify for tax-exempt financing as "dock and wharf" facilities, such as a marine LNG terminal.[29] The eligible portion would likely only be a fraction of the entire cost and, therefore, use of this exception would still mean that all or substantially all of the project could be financed only on a taxable basis.

Another exception under federal law is the private-activities cap. Under this cap, each state is allowed to issue tax-exempt bonds for private activities up to certain limits. In the case of Alaska, the limit is currently $187.5 million per year. However, this amount already is fully subscribed each year for debt issuances of the Alaska Industrial Development and Export Authority, Alaska Housing Finance Corporation, Alaska Student Loan Corporation, municipalities and other purposes. The State Bond Committee allocates the annual allowance.

The tax treatment of the debt does not change depending upon the identity of the issuer. Thus, debt issued by a conduit or other state agency is not any more likely to be exempt. In addition, the type of debt also does not necessarily affect its tax status. Tax status depends upon the use of the proceeds and the sources of repayment of the debt.

There is a market for taxable bonds. However, the market for this debt is untested since there have been no comparable issues by other states in the past.[30]

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[29] There has been at least one successful tax-exempt funding of a marine terminal in Alaska. When the state refused in 1974 to support state tax-exempt financing for TAPS, the City of Valdez was considered as a potential issuer for at least the marine terminal facilities. In that year, the voters of Valdez authorized a bond issue of up to $2 billion for financing the marine terminal facility. In 1977, after receipt of an IRS ruling recognizing the tax-exempt treatment of the bonds, the City of Valdez, on behalf of ARCO and with utilization of ARCO's credit capacity, issued $265 million in Terminal Revenue Bonds. These bonds, as all successor terminal bond issuances, were secured solely by the project revenues and the company's credit. The credit of Valdez was not required. The city received a 1 percent impact fee from the financing and began to accumulate the funds in a permanent fund. Subsequently, in 1977, SOHIO undertook the same financing, and by the end of 1978 a total of $1.265 billion of Terminal Revenue Bonds had been issued for each of the various owners of the marine terminal. Since the initial issuance of the bonds, there have been numerous refundings with extensions of bond maturities up to 2037 in some cases. Almost all of the original debt amount still is outstanding.

[30] For example, since 1996 the largest taxable municipal general obligation bond issuance appears to have been by the City of New York for general purposes and public improvements in the principal amount of $434.1 million. Source: Thompson Financial.

Because the state's private-activity cap already is fully utilized—and insufficient to finance much of a state investment in the gasline—and because only a fraction of the project could qualify as a dock or wharf facility, the analysis in this report is based on the reasonable assumption that almost all debt issued by the state for this project would be taxable. Under this assumption, debt participation by the state does not appear economically attractive, because the state probably could not obtain substantially better interest rates than private parties. The state could obtain better interest rates only if it could issue tax-exempt municipal bonds for the project under a special exception to federal law. This option is discussed below.

### Tax-Exempt Financing

As discussed above, the state would need a special exception to federal law in order to issue tax-exempt bonds to finance the Alaska Gas Pipeline.[31] Although rare, such special exceptions do occur. Here, a special exception would be predicated on the fact that the pipeline is a unique transportation project that could provide a stable domestic source of energy. Given that the project would serve the important national interest of making the country less dependent on foreign energy, the possibility of tax-exempt financing is worth considering.

If tax-exempt financing were available, what would it look like?

First, we assume the state would issue some form of revenue bond, not a general obligation bond, because a general obligation bond would put an intolerable amount of financial risk on the state.

Second, as required under federal law, the state would be the owner of at least as much of the project as it financed through tax-exempt bonds.

Third, most likely a gasline revenue bond would be in the form of an industrial development bond issued through a state authority such as AIDEA or other special-purpose entity that the legislature might create. The bond would be issued by the authority to finance facilities that are then leased to the private-entity user at a rent equal to debt service on the bonds and for a

[31] The advantage of the gasline qualifying as a permitted private activity is that the private-activity monetary cap does not apply.

term equal to the maturity of the securities. Alternatively, the issuer might be able to loan the proceeds of the industrial development bond directly to the private-entity user on repayment terms equal to the terms on the bonds. In either form, the responsibility for construction and operation of the project would remain with the private developers.

Fourth, security for payment of the debt would be revenues from the project itself, likely supported by ship-or-pay contracts with the producer/shippers.

Fifth, the financial markets likely would finance no more than 70 percent of the project with this kind of debt. The remaining 30 percent would have to be an equity contribution. Options for the equity financing would be direct state contribution (which could be $3.5 billion to $4 billion on a $12 billion to $14 billion project cost), or a similar contribution from some other party—for example, the producers could be asked to contribute the 30 percent equity share under contract as a prepaid tariff.

If the state were able to provide tax-exempt financing, would it make the Alaska Gas Pipeline more attractive to the private parties whose participation is necessary to get this project off the ground? This question is difficult to answer. Even though there almost certainly would be an economic benefit from tax-exempt financing, whether the resulting structure is attractive to the producers or pipeline companies is an open question.

A financial analysis of the benefits of tax-exempt financing would have to consider many variables. One of the most important of these is the spread between tax-exempt interest rates and taxable rates. Usually this spread will be around 25 percent (such as 8 percent for taxable bonds and 6 percent for tax-exempt), but it can vary with market conditions and may be different for a project like this.

A second consideration is the value that a private owner gives up when the state takes over ownership of the project. Primary among these foregone benefits is the right to depreciate the asset. The value of this benefit over time to a company will depend on the company's tax rate and its discount rate—i.e., the value it places on having money today rather than in the future. If the producers owned the pipeline, the tax law would allow them to claim accelerated depreciation, under which they would be able to deduct the cost of the pipeline from their taxable income over 16 years, with larger deductions occurring in the first six years.[32] In addition, they could deduct their interest payments. If the state owned the pipeline, the producers could only deduct the cost of their lease payments to the state. Over time, they would deduct roughly the same total that they would have deducted had they owned the project, but it would take much longer to realize the economic benefit of the deduction without the use of accelerated depreciation.

Because of the time value of money, the accelerated depreciation payments allowed under a private-ownership scenario would reduce the economic benefit of tax-exempt financing. In the early years of the project, a private owner would be better off with taxable financing. One attempt to model the cost advantage of tax-exempt financing for a typical producer shows that, under one set of reasonable assumptions, tax-exempt financing is economically advantageous, but it would take 13 years for an owner to realize a cost advantage from tax-exempt financing.

In sum, unlike the other options discussed in this report, tax-exempt financing might make feasible a project that otherwise would be uneconomic. Alternatively, the state might be able to extract an additional state benefit if it were to provide tax-exempt financing to lower the costs for an already profitable project. Since tax-exempt financing does offer financial benefits, the state may consider supporting a federal effort to obtain a tax-exemption for state debt for the project.

Even if tax-exempt financing were an option, however, it is not certain that the sponsors of the Alaska Gas Pipeline would prefer that option. That would depend on the resulting ownership structure and actual savings to the sponsors over their own costs of capital and foregone benefits such as depreciation.[33]

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[32] 26 U.S.C. § 168.

[33] If any portion of the state's equity funds originated from proceeds of a tax-exempt bond, this structure could jeopardize the use of accelerated depreciation by the private entities for the entire project. Under a worst-case scenario, the entire project would be required to use 125 percent of useful-life and straight-line depreciation.

# Ownership Alternatives

SB 158 requires the Department of Revenue to consider specific forms of equity investment in the project. There are two major alternatives: direct state ownership or establishment of a public authority such as the Alaska Industrial and Export Development Authority (AIDEA). The bill also requires the department to consider the merits of a private corporation comprised of Alaska residents who wish to invest in the project. This corporation would own a portion of the project and/or assist in its construction and operation. These alternatives are discussed below.

## Direct State Ownership

The state owns and has financed a variety of public facilities. Although there is no direct constitutional impediment in Alaska to a public/private joint venture, the use of public/private partnerships historically has not been an ownership mechanism for state facilities. However, it is an option for non-public facilities, as occurred in December 2000 when AIDEA took an initial equity stake in Alaska Seafoods International, an Anchorage seafood processing company. AIDEA obtained a larger equity stake in the corporation the next year after the state authority helped restructure the business, which faced a severe cash shortage. Although we are not aware of any situations where the state itself—rather than AIDEA or another agency—directly owns a part interest in a private venture, we also are unaware of any specific legal prohibitions to such a structure.

However, as mentioned in the discussion above, it is important to note that the state is precluded, by the Alaska Constitution, from "lending its credit directly to benefit a private entity." We do not believe that would necessarily prevent the state from taking a stake in a private partnership, as long as the state could show it was not lending its credit to the private entity.

## Public Authority

Funneling the state's investment through a public authority would avoid some of the problems of direct state ownership. A public authority would provide a one-step removal from direct involvement of state government with a private company. With an independent board of directors and executive director (albeit possibly appointed by the governor and even confirmed by the legislature), and statutory provisions that provided the authority with a degree of management independence, an independent authority could act and react more like a private business entity.

The creating legislative enactment could provide an authority with independent corporate powers, bond issuance and credit guarantee capacities, and the ability to engage independently in federal programs. A separate legal authority also could maintain a degree of separation from the customary political process associated with state government and establish a clearly dividing line for liability. The assets delivered and pledged to the authority could be the only public assets available to satisfy claims against the project, possibly shielding the state from any potential damages.

## Private Corporation of Alaska Citizens

Alaska could participate in the ownership, construction or operation of a gas project by creating a private corporation expressly for that purpose. It may be possible, moreover, to devise strategies that leave most of the shares of the corporation in the hands of state government and its citizens. The approach nevertheless raises a number of questions that should be addressed before it is seriously considered.

This concept was proposed in a report prepared for the state in 1978 by Dillon, Read & Co. It was modeled upon the structure of the Alberta Energy Corporation (AEC), which at that time was owned in part by the government of the Canadian Province of Alberta. AEC was capitalized initially by the provincial government with an investment of $75 million. Subsequently, in 1975, Alberta offered shares worth an additional $75 million publicly. Provincial residents, however, were given a priority during the first three weeks of the offering. All of the shares were sold during the priority period, so afterward AEC had a total capitalization of $150 million, with 50 percent of the corporation owned by Alberta residents and the other 50 percent owned by the province.

The Dillon, Read report suggested this model as a possible approach for Alaska, based on the assumption that funds used for the state's initial equity investment in the corporation could be obtained by issuing tax-exempt general obligation or revenue bonds. Under existing law, a private (non-governmental) corporation may not issue tax-exempt bonds, except in compliance with certain Internal Revenue procedures for non-profit corporations.

Several things have changed since the Dillon, Read report was issued. Over the years, the Alberta government has extricated itself from its ownership of AEC. The province divested the last of its shares in 1993. And, more noteworthy, U.S. tax laws changed dramatically in 1986. As a consequence, bonds used to raise funds to capitalize a private corporation would, almost certainly, not qualify as tax-exempt.

This approach of a private corporation raises a number of issues. For example, attempting to limit shareholders exclusively to Alaska citizens may present practical problems and perhaps even legal ones. As a practical matter, a residency requirement for shareholders may be difficult to monitor and enforce. It almost certainly would diminish the market value of the corporation's shares. And, as far as the U.S. legal system is concerned, this concept may be unprecedented. We are not aware of any state forming a private corporation, whose shareholders are limited to state residents, in order to advance a development project in the state. Legal challenges to this approach are therefore possible. Among other things, the validity of the residents-only shareholder's rule might be challenged as lacking a legitimate public purpose. The restriction also might be challenged under the Privileges and Immunities Clause of the U.S. Constitution[34]—which essentially guarantees equal treatment among citizens by state governments—notwithstanding the "private" nature of the corporation. Before following this approach, a thorough analysis of questions like these would be advisable.

More significantly, this approach fails to offer any tax or financial advantage over the development of a project by existing private corporations. As previously mentioned, the tax code underwent significant revision in 1986, and Dillon, Read's assumption in 1978—that the state could issue tax-exempt bonds to raise funds for the initial capitalization of the corporation—is no longer valid.

[34] ..."No state shall make or enforce any law which shall abridge the privileges or immunities of citizens of the United States"... U.S. Const., Amend. XIV, sec. 1.

It is also difficult to see what advantages this approach provides over other, more readily available, alternatives. Providing Alaskans the opportunity to hold shares in the project, by itself, would appear to be an insufficient justification, because Alaska and its citizens already can hold shares in the corporations with an interest in developing North Slope gas. A new, state-sponsored corporation is highly unlikely to offer a "smarter" option for development, because existing corporations with experience building and operating large gas pipeline projects are likely to build and operate the North Slope project better, for less.

The potential upside from participating in this project is not extraordinary, because the earnings on the corporation's gas pipeline investment would be regulated by FERC.

And participating in order to influence the pipeline route is unnecessary, since Alaska law already forecloses the Over-the-Top Route.

Due to the size and scope of this idea, if the legislature wishes to pursue it further we recommend that special tax, securities and investment banking advisers be retained.

The preceding concerns, of course, are not exhaustive. Using state revenues to form a gas pipeline corporation would further concentrate the state's—and, therefore, its citizens'—investments toward oil- and gas-related activities, while diversification away from such activities may be a more prudent investment strategy for a state already so dependent on oil and gas.

In addition, the new corporation presumably would borrow most of the funds necessary to build the project or its share of the project. But lenders would require long-term, ship-or-pay commitments from the major North Slope gas owners before they would be willing to risk their funds. These gas owners, however, would not enter long-term, ship-or-pay commitments in support of a project (other than one they themselves sponsor) unless (1) they conclude that the project as a whole is economic, and (2) they believe the project sponsor can build the project and operate it reliably at a lower cost.

SECTION 6

# Investment Setting

This section discusses several factors affecting potential risks and returns for a state investment in the Alaska Gas Pipeline. The discussion considers both pipeline ownership and acquisition of pipeline capacity rights. The key factors discussed are future gas market conditions, governmental regulation, permit requirements and project costs.

## Future Gas Market Conditions

A key factor to the feasibility of the Alaska Gas Pipeline is future conditions in national and global natural gas markets. This section reviews the outlook for market supply and demand, and provides information on price trends, uncertainties and forecasts.[35]

### Market Supply and Demand

North America's natural gas industry is at a crossroads. Consumption in the United States increased at an average of 1.3 percent per year in the 10 years from 1989 through 1999, based primarily on growth in power generation and industrial markets. Residential and commercial consumption remained essentially constant during the period. Key future growth opportunities come from increasing natural gas use in power generation and refocusing national policy toward domestic and environmentally sound energy production and use.

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[35] Much of the basic information in this section was assembled from two recent research reports on North American natural gas:

- INGAA Foundation, Inc. *Future Natural Gas Supplies from the Alaskan and Canadian Frontier*. Prepared by Houston Energy Group, LLC, and URS Corporation. July 2001.
- Cambridge Energy Research Associates (CERA). *Toward New Frontiers: The Future of Gas Supply in North America*. A CERA Multiclient Study. Final Report. Winter 2001.

Forecasts of U.S. gas supply and demand generally project increases in the growth rate of industrial uses of natural gas. As shown in Table 6-1, forecasts available from eight sources call for growth ranging from 1.7 percent to 2.7 percent per year in the period between 1999 and 2015.

**TABLE 6-1**
Projection of US Natural Gas Market Parameters, 2015
(TCF unless otherwise noted)

| | | 2015 Projections | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Cambridge Energy Research Associates | | | | | | | | | |
| | 1999 | Low | Medium | High | INGAA Foundation | Canadian Energy Research Institute | Energy Information Adminis-tration | Gas Research Institute | Data Research Institute | American Gas Association | National Petroleum Council |
| **Demand** | | | | | | | | | | | |
| Residential | 4.7 | 5.5 | 4.8 | 4.9 | 5.8 | | 5.7 | 5.7 | 5.6 | 5.9 | 6.0 |
| Commercial | 3.1 | 3.6 | 3.7 | 4.0 | 4.0 | | 4.2 | 4.1 | 3.5 | 4.0 | 4.0 |
| Industrial | 6.9 | 6.6 | 6.8 | 8.1 | 9.1 | | 9.8 | 11.0 | 8.4 | 10.7 | 10.7 |
| Power | 4.9 | 10.2 | 11.1 | 12.5 | 7.7 | | 8.9 | 8.7 | 9.3 | 7.1 | 7.7 |
| Other | 1.9 | 2.2 | 2.3 | 2.5 | 3.3 | | 2.9 | 3.3 | 2.9 | 3.2 | 3.1 |
| Total | 21.5 | 28.1 | 28.7 | 32.1 | 29.9 | 28.9 | 31.5 | 32.8 | 29.7 | 30.9 | 31.5 |
| **Supply** | | | | | | | | | | | |
| Domestic Production | 18.2 | 21.3 | 20.9 | 23.7 | 23.1 | 24.6 | 26.3 | 28.8 | 24.0 | 26.7 | 26.8 |
| Imports | 3.3 | 6.9 | 7.7 | 8.4 | 6.8 | 4.3 | 5.2 | 4.0 | 5.7 | 4.2 | 4.7 |
| Total | 21.5 | 28.2 | 28.7 | 32.1 | 29.9 | 28.9 | 31.5 | 32.8 | 29.7 | 30.9 | 31.5 |
| Price per MMBtu, Chicago Hub (1999$) | $ 2.29 | $ 2.60 | $ 3.07 | $ 3.18 | $ 3.50 * | | | | | | |

| | Growth Rate, 1999-2015 | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Cambridge Energy Research Associates | | | | | | | | | |
| | Low | Medium | High | INGAA Foundation | Canadian Energy Research Institute | Energy Information Adminis-tration | Gas Research Institute | Data Research Institute | American Gas Association | National Petroleum Council |
| **Demand** | | | | | | | | | | |
| Residential | 1.0% | 0.1% | 0.3% | 1.3% | | 1.2% | 1.2% | 1.1% | 1.4% | 1.5% |
| Commercial | 0.9% | 1.1% | 1.6% | 1.6% | | 1.9% | 1.8% | 0.8% | 1.6% | 1.6% |
| Industrial | -0.3% | -0.1% | 1.0% | 1.7% | | 2.2% | 3.0% | 1.2% | 2.8% | 2.8% |
| Power | 4.7% | 5.2% | 6.0% | 2.9% | | 3.8% | 3.7% | 4.1% | 2.3% | 2.9% |
| Other | 0.9% | 1.2% | 1.7% | 3.5% | | 2.7% | 3.5% | 2.7% | 3.3% | 3.1% |
| Total | 1.7% | 1.8% | 2.5% | 2.1% | 1.9% | 2.4% | 2.7% | 2.0% | 2.3% | 2.4% |
| **Supply** | | | | | | | | | | |
| Domestic Production | 1.0% | 0.9% | 1.7% | 1.5% | 1.9% | 2.3% | 2.9% | 1.7% | 2.4% | 2.4% |
| Imports | 4.7% | 5.4% | 6.0% | 4.6% | 1.7% | 2.9% | 1.2% | 3.5% | 1.5% | 2.2% |
| Total | 1.7% | 1.8% | 2.5% | 2.1% | 1.9% | 2.4% | 2.7% | 2.0% | 2.3% | 2.4% |
| Price per MMBtu, Chicago Hub (1999$) | 0.8% | 1.8% | 2.1% | 2.7% | | | | | | |

* Average of projected range of $3.00 to $4.00 per MMBtu

While the forecasts are for growth, there is significant uncertainty about how the gas markets will in fact develop. Factors contributing to this uncertainty are as follows:

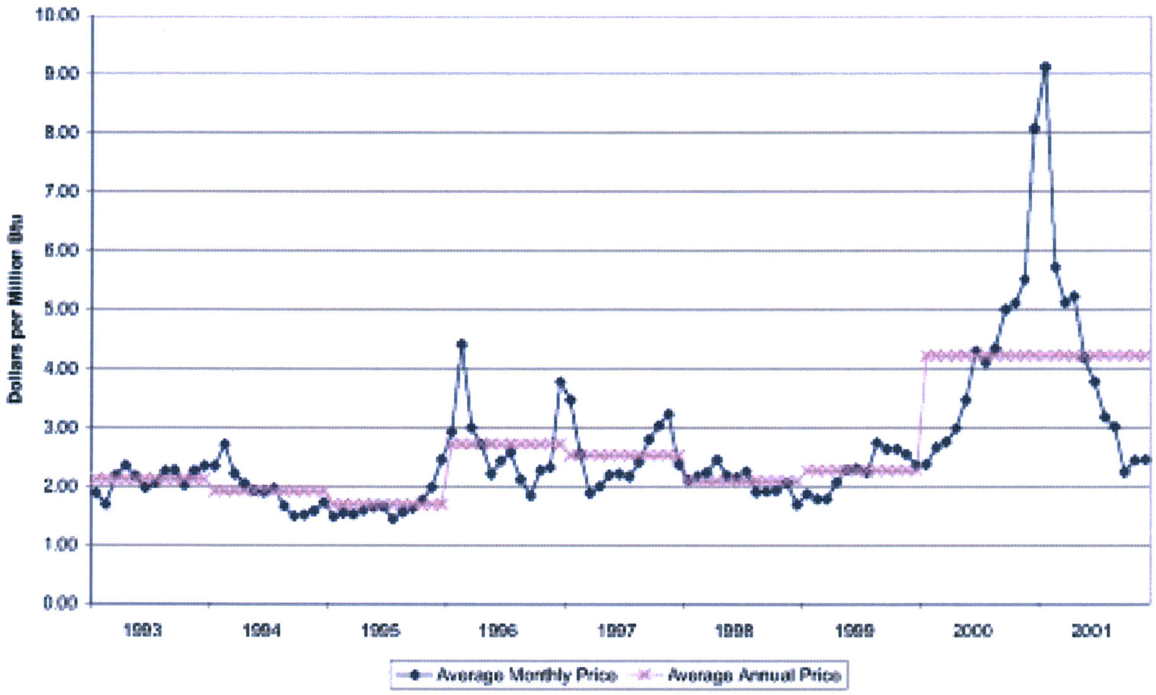
- Projected sources of new supply vary widely. Depending on the forecast, imports from Canada and LNG are projected to supply from 6 percent to 60 percent of the market growth between 1999 and 2015. Projects that can respond quickly to market opportunities will have a competitive advantage.

- The boom-and-bust character of the market will continue. This will result from the inability to time incremental growth in supply and demand. For example, new supply sources such as from the North Slope, deepwater Gulf of Mexico and LNG sources can immediately introduce large volumes of gas to the market without similar increases in demand.
- Although significant growth in power generation markets seems likely, some forecasts are for moderate growth. For example, the Interstate Natural Gas Association of America (INGAA) projects only a 2.9 percent annual growth in natural gas use by power plants.
- Forecasts of relatively rapid growth in power generation are based on the environmental advantages of natural gas and its low cost relative to other fuel alternatives. If natural gas prices were to increase to levels above competing fuels, the growth rate in gas-fired power generation would moderate or even become negative if the price differential resulted in fuel substitution.
- Growth in other sectors is less certain. Higher than traditional price levels could cause the residential and commercial sectors to remain at historic levels as they have over the past 10 years. Energy efficiency advances continue to dampen demands in these sectors.
- Industrial usage is partially a function of manufacturing facilities being located in the United States and Canada as opposed to other countries. The ongoing trend toward a global economy and export of manufacturing jobs from the United States and Canada translates into uncertainty about long-term energy demands by the manufacturing sector in North America.

## Prices

Wholesale gas prices reflect the volatile nature of natural gas market supply and demand in North America and therefore vary widely. Spot market prices for gas traded at Henry Hub are indicative of national price trends. As shown in Figure 6-1, these prices can vary sharply. Between full market deregulation in 1993 and the end of the decade, average monthly prices ranged from a low of $1.44 per million Btu in July 1995 to a high of $4.41 seven months later in February 1996. Serious national shortages in 2000 and 2001 sent the average monthly price as high as $9.13 in January 2001. Since then, shortages have given way to surpluses and the price fell to $2.24 in September 2001. Prices held around $2.10 to $2.30 throughout most of January 2002.

**Figure 6-1**
**Average Natural Gas Prices at Henry Hub**




Average annual prices, also shown in Figure 6-1, naturally show more limited volatility than the monthly data. Although price changes from year to year can be dramatic, there has not been a long-term trend toward significantly changed prices. While prices in 2000 and 2001 were substantially higher than historic levels, prices in 2002 are projected to be in line with historic long-term trends.

Although spot prices will continue to vary, consideration of prices for gas produced at the North Slope should focus more on the long-term average market price. Long-term price projections are for price levels to increase in real terms (i.e. more rapidly than general inflation). As shown in Table 6-1, Cambridge Energy Research Associates (CERA) forecasts

2015 prices to range between $2.60 and $3.18 per million Btu, while INGAA forecasts a price range of $3 to $4 with an average of about $3.50 (in 1999 dollars).

At price levels of over $4.00 per million Btu, market forces would be at work to reduce prices. These forces would likely include greater development of clean-coal technology, delays in nuclear plant retirements, coal gasification, increased LNG imports, fuel substitution at some industrial and power plants, greater deepwater gas supply development, and arctic frontier (North Slope/Mackenzie Delta) gas development. Natural gas prices less than about $2.25 would likely result in increases in demand and upward price pressure as consumers substitute gas for alternative energy sources.

North America market demand would not immediately grow to fully accept the incremental arctic frontier supply (assumed to be 2.5 bcf/d initially and 4 to 6 bcf/d soon after) upon completion of a gasline. The result would be a short-term production surplus that would drive down prices in the North America market during the surplus period. It is anticipated, however, that the long-term overall effect of arctic frontier gas would be to stabilize prices because of the magnitude of the resource.

The price of LNG supplies entering the North American gas grid is estimated by INGAA and CERA to range from $2.50 to $4 per million Btu, a value consistent with the long-term price range estimated for conventional natural gas in this market.

# Commercial Regulation

Building a new pipeline today requires resolution of numerous jurisdictional, contracting, operation and construction issues. To reach a point at which financing is concluded, and construction and ultimate operation can commence, all these facets of a pipeline must be meshed together into a workable package. A natural gas pipeline through Alaska has experienced all these issues in the past. In some situations, specific solutions have been approved by various governmental authorities and regulatory bodies.

However, since the time the original pipeline approvals were given, the natural gas market and its regulation have changed significantly. Pipelines have become fee-for-service carriers with open access, and transportation services have been unbundled. As a result, pipelines no longer buy gas in the production field and sell it downstream as a bundled gas service. Gas producers and end-users now directly enter into contracts, with pipelines simply providing transportation services.

This section reviews issues and trends in the natural gas market and its regulation. The review covers the regulatory environment that was in place when Alaska gas pipeline regulations were previously developed, as well as the regulatory environment that exists today. This section also identifies complications and uncertainties that exist in applying the previously derived solutions to today's market dynamics and regulatory environment. Finally, this section provides perspective on regulatory risks that are implicit to ownership of an Alaska gas pipeline.

## Regulatory History

### Legislation and Market Conditions in the 1970s

During consideration of natural gas pipeline construction from Alaska to the Lower 48 states in the 1960s and 1970s, much preparatory work was done on routing, government approvals and tariffs. This work was incorporated in the Alaska Natural Gas Transportation Act of 1976 (ANGTA) in the United States, and in the Northern Pipeline Act of 1978 in Canada. ANGTA was enacted to expedite the certification process that otherwise would have been conducted for natural gas pipeline approval under the federal Natural Gas Act. Following enactment of ANGTA, the President selected the Alaska Highway route and the Alaska Natural Gas Transportation System (ANGTS) in his *Decision and Report to Congress on the Alaska Natural Gas Transportation System* (President's Decision). In 1977 the United States and Canada signed the Agreement Applicable to a Northern Natural Gas Pipeline (U.S./Canada Agreement). This treaty selected the route, chose the companies that would build and operate the system, established tariff principles, and set the terms and principles to be followed in facilitating the construction and operation of ANGTS.

ANGTA and the U.S./Canada Agreement are very comprehensive and, had they been used as the basis for construction of the gas pipeline in the 1970s, they would have addressed most issues necessary to achieve construction and ongoing commercial operation of the Alaska pipeline network. They were a well-crafted compromise, meeting the needs of the parties involved in the development of gas production facilities, gas transportation facilities, and markets *at that time*.

During the 1970s, the North American natural gas marketplace was very different from what it is today. In the United States, domestic production of natural gas was conducted through long-term contracts under long-term price arrangements. Under the U.S. Supreme Court decision in the Phillips case in 1954, commodity prices in the United States were controlled. Special terms and conditions were entered into between producers and pipelines that generally defined the costs of delivery of natural gas service to a city-gate, usually a regulated gas distribution company. Gas pipeline companies built facilities to match the gas supply arrangements they entered into with producers. They would ordinarily resell this gas through contracts, and tariff terms would match the contract and tariff term they had in their own gas supply contracts. Cost of service was the basis used to determine tariffs. Rates were calculated to recover costs associated with the development of the gas supply and facilities necessary to bring the gas supplies to the ultimate market.

These tariff provisions usually covered the cost of the commodity, expenses associated with its delivery, and depreciation, return and taxes on the facilities necessary to deliver it. These tariffs were synchronized to create financial terms acceptable to owners and lenders of parties that built and owned the physical assets. Because of the scale of the investment involved, incentive return features were sometimes built into the tariff and approved as part of the overall package of approvals.

In the 1970s, the expected gas market for Alaska gas was the Lower 48 states. Traditional gas supplies in North America were in steep decline, and Alaska gas was expected to fill a large portion of the decline in the traditional U.S. supply. In anticipation of this decline, major U.S. buyers of gas (primarily gas distribution companies and/or electric companies with gas-fired power generation) were prepared to enter into long-term contracts to purchase gas from Alaska. For this to occur, a complete set of contractual services from the wellhead to the burner tip would be necessary. Several parties eagerly stepped forward to fill this role.

Legal and regulatory complications emerged involving facilities and contracts in multiple jurisdictions in two sovereign nations. Many years of discussion and debate concluded in the passage of ANGTA. From a commercial standpoint, what emerged was a set of agreements that would assist the financing of the transportation systems necessary to deliver natural gas to the U.S. markets. These agreements were an attempt to balance the risk of construction costs and construction timing with the assurance of delivered commodity cost recovery and equity returns to investors. They were an effective set of compromises for the political, marketing and regulatory world of the time.

**Regulatory Evolution, 1980s to 1990s**

North America's natural gas markets changed dramatically during the 1980s and 1990s. Gas supply was short during the early 1980s, and its use as a boiler fuel was effectively eliminated under the U.S. Fuel Use Act. The Canadian government tested several approaches to pricing of gas for export to the U.S., culminating in a $4.94/mcf uniform border price tied to the cost of alternative fuel. These types of cartel-like situations stimulated congressional action and led to partial decontrol of gas prices under the Natural Gas Policy Act (NGPA) of 1978.

This became the initial stimulus for a series of regulatory investigations that led to Federal Energy Regulatory Commission (FERC) Order 436 (Open Access), Order 500 (Take or Pay), and Order 636 (Unbundled Transportation). The NGPA and these orders effectively deregulated commodity prices and opened the national pipeline grid to a new paradigm of competition.

These orders completely restructured the North America gas market. Effectively, gas prices became completely decontrolled at the wellhead; gas supply contracts between pipelines and gas producers were bought out; gas transportation moved toward fee-for-service carriage status (pipeline service became transportation only); and end-users, marketers, brokers and producers all became active purchasers, transporters and sales agents of gas supply. At the city-gate, a variety of state or provincial programs were approved at the distribution company level to allow full or partial direct sales of gas supply to end-users.

By the end of the 1990s, producers and brokers directly sold natural gas into any market they elected at negotiated prices. Vertical integration of the industry became completely fragmented. To move gas to market, one needed to buy the gas at some point in the delivery chain, obtain transportation service to a market, and deliver and bill for the ultimate gas delivery and associated costs. Each function of the previously integrated system (production, transportation and distribution) was substantially restructured into unbundled, independent activities.

In tandem with the deregulation of gas markets, the process for building new pipeline infrastructure changed as well. Building pipe from new supply areas or even expanding existing pipe to accommodate increased volumes on existing pipeline systems was no longer an arrangement generally negotiated by a pipeline backed by its gas supply contracts and sales arrangements to gas distribution customers.

Today, all parties have equal opportunity to participate in this process at each stage. Indeed, the regulatory policy has been to encourage open, multiple-party access to gas transportation and sales opportunities to stimulate competition and offer choices and alternatives to consumers of natural gas. This also created new businesses and entities all with a stake in an unbundled, deregulated commodity gas world. This guaranteed that the regulatory and business process would have more players and become more fragmented and complex. The net result is an increased degree of difficulty in moving major infrastructure projects through the regulatory process. It takes consensus or settlement to avoid litigation. Litigation means that ultimate resolution of authorization to build and construct could take years. To move a major infrastructure project forward in today's regulatory world is a formidable effort involving many parties with differing interests and objectives.

**North Slope Gas and ANGTA in 2002**

As it pertains to development of North Slope gas, the net result of the regulatory structure revolution is to call into question the current applicability of ANGTA. How does, or can, it fit into a changed regulatory environment? At the request of the U.S. Senate Committee on Energy and Natural Resources, FERC recently issued a report assessing the application of ANGTA to the current gas pipeline proposals (FERC, 2001). The results of the report can be summarized in the following opinions that were offered by the FERC chairman in his letter transmitting the report:

- Although ANGTA is still valid, there are questions as to the extent ANGTA provisions can reasonably be applied. Economic and technological changes in the past 25 years make it certain that the sponsor would need to revise the ANGTS option from the approved proposal. In addition, FERC "is likely to be required to conduct additional environmental analysis." ANGTA gives FERC "broad authority to amend" the certificate if it does not result in change in "the basic nature and general route of the approved transportation system." Although FERC is unlikely to adhere strictly to conditions that are no longer practical or technologically optimal, it is not clear how much latitude either the project sponsor or FERC has to revise the ANGTS without further congressional action.

- There appears to be nothing in ANGTA that prevents FERC from considering, under the Natural Gas Act, other proposals filed by other sponsors or routes different from the ANGTS route. However, limitations placed by the ANGTA on such FERC considerations are unclear and might also require clarification from Congress.

## Major Regulatory Issues for Transporting Alaska Gas—2002 and Beyond

### Open Access

U.S. pipelines are built when their sponsors obtain and accept a Certificate of Public Convenience and Necessity from FERC under Section 7 of the Natural Gas Act. Canadian pipelines need similar certificate authority, usually from the National Energy Board (NEB). To move gas from Alaska, multiple jurisdictions would exercise regulatory authority, however, the primary regulatory authorities would probably be FERC jurisdiction within Alaska, NEB jurisdiction within Canada, and FERC jurisdiction again downstream to ultimate markets in the United States.

To construct a multi-jurisdictional pipeline and get it financed in a timely manner requires regulatory approvals, a known and agreed-upon tariff structure, an approved pipeline route and set of initial rates, and transportation agreements that have a term and volume to allow financing and that mirror each other by jurisdiction and in receipt and delivery point. Each section of an integrated, multi-jurisdictional pipeline needs to have understood contract terms that match adjoining upstream and downstream facilities. This includes transportation volumes (size of pipe), gas quality standards (type of gas), known tariff structure (the cost to move the gas from Point A to Point B), and simultaneous service. Each piece of the pipe must be operational concurrently, must physically be capable of moving the volumes nominated by its shippers or upstream pipeline, and be able to deliver like volumes into downstream pipelines or to downstream customers. The contract volumes, terms, and titles need to match. As noted above, under ANGTA, these issues were largely negotiated as part of the supply arrangements assumed by the pipelines. In today's world, this might not work.

**Open Season Processes**

In a world after FERC Order 636, pipelines need to use a nondiscriminatory process to solicit contracts for transportation service. This is true both for a new pipeline and for expansion of an existing pipeline. Typically this is done through a so-called "open season" solicitation. The open season announces the intention of a pipeline company to build new facilities based upon an expression of interest by parties willing to contract for service on those new facilities.

The open season can be done in a variety of ways, but generally it leads to a process yielding binding transportation agreements of a term and volume adequate for regulatory approval of a certificate to construct and for ultimate financing approval. This means that all parties are given simultaneous equal opportunity to "bid" for pipeline space under a clearly defined set of time frames and rules. Ordinarily bidders must meet minimum standards (including demonstration of credit support) to be awarded transportation space.

For a multi-jurisdictional pipeline such as an Alaska pipeline project , the combined project would need to "perfect" contract support for each leg of the pipeline (i.e. Alaska, Canada, Lower 48 states) to allow a complete, coincident contract path for the cumulative volumes. ANGTA did not contemplate an open season process or a Section 7 NGA filing, because the filing authority was ANGTA itself. It is not evident how these issues would be resolved. The manner by which firm capacity would be obtained for the Alaska pipeline and its alignment with existing downstream pipeline firm capacity is unclear. This might be the most significant issue surrounding the economic and commercial viability of building these pipeline facilities.

**Tariff**

ANGTA contemplated a cost-of-service tariff, common in the period leading up to the ANGTA negotiations. Under this type of tariff, the cost of gas and the cost of owning and operating a pipeline is computed monthly and billed to customers of the pipeline. All costs including return are periodically reviewed for reasonableness, and cost of capital and capital structure are reviewed in periodic rate proceedings, as prescribed in Section 4 of the Natural Gas Act. Within ANGTA, an incentive rate-of-return feature was included to recognize the risk and cost of the formidable undertaking involved in a project to move large quantities of Alaska natural gas such a great distance to market. The concept involved a 50-basis-point risk premium on the equity return.

This type of cost-of-service tariff is now used less and less frequently both in the United States and Canada. Within the United States, tariff design has moved toward a straight fixed variable (SFV) rate design. This tariff approach does not have monthly cost adjustments. There is no longer a requirement for periodic rate filings under Section 4, and rate proceedings are generally the prerogative of pipeline owners or can be initiated by other parties under Section 5 of the NGA. Because most costs are fixed, the primary basis for cost recovery is a fixed-demand charge rather than in a commodity charge.[36]

A similar tariff approach has evolved within Canada for NEB-regulated pipelines. An SFV rate design is matched with a periodic review of rate levels and an incentive type of rate design that allows pipeline companies to share expense and capital cost savings with shippers between periodic rate reviews.

Another change is that ANGTA provided full cost-of-service rate recovery for all costs. This would have included the actual costs of construction if those costs exceeded the estimated costs filed with the certificate application. Today's pipeline rate regulation has moved toward putting the pipeline owners at risk for cost overruns or increases. Initial operating rates are established based upon estimated costs to complete a project. Pipeline owners today have a tremendous incentive to control project costs because initial rates usually are based upon

[36] FERC has expressed a willingness to consider alternative forms of rate design, and this has occurred when a pipeline and its customers can structure a rate design with sufficient support to be filed as a settlement offer with FERC.

estimated costs to completion. Should actual costs exceed these costs, they have the opportunity to try to recover them in a rate proceeding (and indeed, the burden of proof to demonstrate prudence of costs falls on parties making those arguments). However, rate proceedings are costly and inherently uncertain as to outcome. Hence, they are not the recourse pipeline owners are prone to seek. Pipeline owners have a real incentive to contain construction costs to certificated levels.

A major tariff issue in today's regulatory environment is the issue of rolled-in vs. incremental rates for service. This is particularly of concern for major new pipeline investments that integrate with downstream existing pipelines. New facilities under ANGTA were, of necessity, incrementally priced. There were no existing facilities to roll the costs into. Although the Canadian ANTGS prebuild in 1983 was incrementally tolled, incremental vs. rolled-in tolling has continued to be an issue for every major expansion of the prebuild portions of the ANGTS system since that time. The NEB has continued to support a rolled-in standard for Canadian mainline pipelines, primarily on TransCanada.

A pipeline from the North Slope to Alberta would constitute a new transportation route, so service on the pipeline would be incrementally priced. However, capacity on pipelines and routes out of Alberta would necessarily be expanded and therefore be subject to the incremental vs. rolled-in pricing controversy.

Other major issues in the current integrated North America gas market are common tariffs and electronic access to information. Today's market is an open market. Gas is a true commodity and is interchanged both financially and physically through a variety of contract forms and terms. These terms necessitate common or like language in tariffs defining everything from gas quality to nomination standards and uniform multisystem transportation agreements. None of these issues were contemplated within ANGTA. A variety of modern issues ranging from gas quality to contract terminology were not contemplated or built into ANGTA.

The Alliance Pipeline Project from Northern British Columbia to Chicago is an example of a new major pipeline project where all these issues had to be anticipated and built into the project design, and ultimately into the project approvals and financing. This is a bullet high-pressure system that takes gas from the start of the project in the north and moves it unprocessed directly through the gas market areas in Alberta and the northern tier of the United States into the Chicago marketplace. In Chicago, it is processed and then mixed with the rest of the North America pipeline system for delivery to market. The Alliance Pipeline has one major receipt point and one major delivery point. It operates with unique tariffs in Canada and in the United States. It was designed, certificated and built with all these provisions in conformity.

An Alaska pipeline system probably would be more complex if it had receipt and delivery capability at multiple points along the pipeline. Ultimately, it would commingle gas with other gas supplies in existing Canadian and United States pipeline systems. As a result, the tariffs and operational nature of these systems would need to integrate in the tariffs, contracts, electronic bulletin boards and nomenclature of the existing pipeline infrastructure. ANGTA did not consider these complexities.

**Implications for State Ownership**

The Alaska gas pipeline would be regulated by FERC in the United States and the NEB in Canada. The tariff would likely be negotiated between the pipeline owners and customers that reserve capacity rights on the system through an open season process. These capacity reservations would essentially be a purchase of rights in that they would be in the form of a contractual obligation to ship or pay for a specified capacity on the pipeline for a long term (likely to be 15 to 25 years). FERC and the NEB would have ultimate approval of the tariff and the return to the pipeline owners. The approved Alliance Pipeline tariff had a 70/30 debt/equity ratio with a 12 percent return to equity. Because of cost overruns, the return to equity was reduced to about 10.5 percent.

If the state were to invest in the Alaska gas pipeline, the state could expect to also have its rate of return established through a open season negotiation and FERC/NEB approval process. Similar to the Alliance project, there would be risks of lower than FERC/NEB-approved returns. At the same time, incentives could be built into the tariff that would allow pipeline owners to earn a higher return. Ownership risks and returns are discussed further in Section 7.

An important aspect of pipeline ownership is that it would not automatically provide the state with capacity to move gas to market. That capacity must be separately reserved. This is typically done through the open season process described above.

Alternatively, or in addition to pipeline ownership, the state might seek to purchase a share of pipeline capacity rights during the open season process. The purpose of such a purchase would be to provide a pathway for the state to transport its gas to market if it were to choose to take its 12.5 percent royalty share of gas production in-kind. Such a capacity purchase might also be established to provide a pathway to market for gas discovered by others parties in the future. This is also further discussed in Section 7.

## Environmental Regulation

Construction authority for pipelines in Canada and the United States requires review under the U.S. National Environmental Policy Act and the Canadian Environmental Protection Act. The U.S. process for approving a certificate of convenience and necessity involves a dual path for review. One track looks solely at environmental issues, and the other path looks at commercial issues. Typically this path converges with independent reports on both, which are packaged together into a final decision rendering or denying a certificate.

For the ANGTS, this process was streamlined. Much of the environmental review process either has been approved previously or has identified expedited processes for approval. The FERC staff recognizes the unique nature of the ANGTS approvals, but point out that environmental laws and issues have evolved substantially since ANGTS was approved.

Today's pipeline construction procedures are tied to specific mitigation plans to protect and preserve threatened habitat, species, archeological sites and wetlands. It would be difficult to have the ANGTS approvals withstand the rigorous scrutiny that would surely emerge from multiple parties, given the scope of the ANGTS project. It seems reasonable to conclude that significant augmentation of the existing ANGTS environmental findings and processes would be necessary to lead to new or final certificates for timely construction.

# Permits

An Alaska gas pipeline would require numerous U.S. and Canadian permits. All of the current pipeline options are in varying stages of permit acquisition, but the most advanced is the ANGTS. There is considerable interest and uncertainty about the significance of existing permits currently held by Foothills Pipe Line Ltd. for the ANGTS option. As mentioned above, FERC in 1977 issued conditional certificates of public convenience and necessity to the sponsors of the Alaska portion of the ANGTS. The FERC order expressly noted the need for further data before it could take final action. In 1978 the Canadian Parliament enacted the Northern Pipeline Act, which incorporated the terms of the U.S./Canada Agreement and issued a Canadian Certificate of Public Convenience and Necessity to the sponsor of the Canadian portion of the ANGTS. Foothills is now the holder of both the U.S. and the Canadian certificates. Application of all of these existing ANGTS permits is subject to the questions raised in Commercial Regulation, above.

Foothills also holds several other ANGTS permits that are still valid in the United States and Canada. Other U.S. permits that have been issued at the federal level include a right-of-way grant issued by the U.S. Bureau of Land Management and Clean Water Act wetlands permits from the U.S. Army Corps of Engineers. Permits at the state level include certificates of reasonable assurance pursuant to Section 401 of the Clean Water Act and a determination of consistency with the Coastal Zone Management Act. A Canadian permit that has been granted in addition to the Certificate of Public Convenience and Necessity is the Yukon right of way. This is an easement that has been signed by federal and provincial governments as well as by the Yukon First Nations.

# Project Costs

As described in Section 3, there are several pipeline routes under consideration for transporting and marketing natural gas from Alaska's North Slope. Project sponsors are continuing to evaluate the costs associated with each of the alternatives. These costs are important to the determination of project feasibility.

Although this report includes analysis of potential returns to investment in the Alaska gas pipeline, it does not attempt to determine the economics of one project alternative against another. Because the state government has designated its preference for the Alaska Highway Route, it has been chosen as the benchmark in this report for state investment analysis.

Data from two sources are available on the cost of the Alaska Highway Route from the North Slope to Alberta: Foothills and the North Slope producers group. Construction costs for only the pipeline, with 4 bcf/d capacity, have been estimated at $9 billion to $10 billion (2001 dollars). As discussed in Section 7, total investment costs, including capitalized financial costs, would be higher. Sponsor estimates of annual operating costs range from $100 million to $200 million.

As discussed in Section 3, other infrastructure would need to be developed to transport North Slope Gas to market. In addition to the Alaska gas pipeline investment (from the North Slope to Alberta), a gas treatment plant at the North Slope and pipeline capacity to transport gas from Alberta to market would be needed. The producers estimate the gas treatment plant to cost about $2.6 billion (2001 dollars). Additional capacity additions from Alberta have not yet been determined. For analysis purposes only, the producers have estimated the cost of a bullet pipeline from Alberta to Chicago to be $5.3 billion. So, while the Alaska gas pipeline is estimated to cost between $9 and $10 billion, the total construction cost to develop and send North Slope gas to market is estimated to be in the range of $17 billion to $18 billion.

There are a number of risks that could cause construction cost overruns. Risks associated with the Alaska gas pipeline are discussed in Section 7.

SECTION 7

# Potential Returns from Pipeline Investment

As described in Section 6, the state could choose to pursue either or both of two ownership options associated with the Alaska Gas Pipeline. These two options are ownership in the pipeline and ownership of capacity rights purchased from the pipeline owner through the open-season process. This section evaluates risks and reviews potential returns associated with each of these two options. Additionally, potential effects on the state's cash flow are discussed.

## Pipeline Ownership

State ownership in the pipeline could conceivably range from partial to full ownership. Given the planning and development investment that private sponsors have already made in the pipeline, the substantial further investment still required, and the fact that the state does not have adequate expertise to lead pipeline development, we do not believe full ownership is a practical option. Accordingly, state ownership would very likely be limited to partial ownership. The state's partial ownership share is usually discussed as being the same ratio as the state's royalty rights to gas produced on the North Slope, or 12.5 percent. However, the state could take ownership at levels above or below this share.

### Ownership Risks

As discussed in Section 6, project ownership would allow the state, as part of the ownership structure, to participate in selling pipeline capacity. But in order to use capacity for its own gas, the state would need to purchase capacity rights under the same open-season rules as any other customer—ownership does not bestow any capacity rights or privileges.

The Alaska Gas Pipeline would be regulated by FERC in the United States and the NEB in Canada. Construction of the project would not begin until long-term contracts are in place to reserve all or most of the system capacity. Tariffs and the return on the investment in the pipeline would be established based on negotiations between pipeline owners and customers that buy capacity rights on the system. Returns on equity investment in the system would be in the range of 12 percent to 13 percent if negotiations and regulatory approval were to follow those that occurred with the Alliance Pipeline Project. There might be incentives that could increase returns above this level.

Although the investment would earn a regulated return, there would be risks of earning a lower return than that established in the negotiation and regulatory approval process. These risks include risk of construction cost overruns, project abandonment or mothballing, inadequate capacity subscription or customer default, operating problems, regulatory setbacks, insurance inadequacies and easement conflicts. Each of these risks is discussed below.

**Construction Cost Overruns**

As described in Section 6, construction of the Alaska Gas Pipeline alone could cost upward of $10 billion in 2001 dollars—a gas conditioning plant on the North Slope and expanded pipeline capacity out of Alberta would be billions more. Although contingencies are included in the sponsor's cost estimates, actual costs could well grow above those estimates. There are a number of developments that could cause cost overruns. These include the following:

- Problems with new technology or approaches associated with the project
- Construction productivity problems in the arctic conditions
- Inadequate skilled labor and other resources to construct the project efficiently
- Construction delays. These could occur from more adverse weather conditions than planned, interruption in delivery of pipeline or other materials, labor disputes, accidents and safety problems, technology difficulties, unplanned environmental occurrences (including archeological finds) and political developments
- Demand for pipe to meet project needs pushing pipe prices above budgeted levels
- Enhanced security in response to terrorist threats
- Mismanagement, particularly of developments that could cause cost overruns

Typically in a regulated environment, however, construction cost overruns are largely recoverable as long as they can be defended as being prudent. For example, cost increases due to project delays because of abnormal weather would be viewed as unavoidable and therefore likely would be added to the owner's rate base. Although other parties, such as pipeline customers or FERC or NEB staff, might resist such adjustments, they would typically have to prove imprudence in order to exclude cost overruns from a revised tariff. If the owner were not able to find ways to contain unavoidable costs through cost reductions elsewhere, FERC or NEB might award it a lower than anticipated rate of return, but this would not likely be a substantial adjustment. So, the pipeline owner's risks from cost overruns are practically limited to imprudent costs, regulatory delays before rate relief is granted for unavoidable cost increases, and a potential for FERC and NEB to allow a lower than planned rate of return due to lower than expected performance in cost management.

**Project Abandonment or Mothballing**

Although contracts signed for pipeline capacity should reduce much of the risk that the Alaska gas pipeline would be abandoned or mothballed (indefinitely delayed), such a risk does exist. It is not unusual for a major energy project to be delayed or abandoned. In fact, ANGTS has already been delayed once. Many investments made in its planning process during the late 1970s and early 1980s are likely to be lost. There have been numerous other smaller energy projects in Alaska that have not been constructed. On a larger scale, during the 1980s, numerous nuclear power projects in the United States were abandoned or mothballed before construction was completed.

Unless the pipeline is not completed at the request of pipeline capacity owners, funds invested in an abandoned project could not be recovered and would be lost to project investors. Similarly, mothballing could result in lost investment or substantially reduced returns on investment made prior to mothballing.

**Inadequate Capacity Subscription or Customer Default**

The pipeline is planned to be full in a few years time and operate at a 95 percent capacity factor. There is some risk that the pipeline would not carry this load level or be subscribed under ship-or-pay contracts through its entire project life. Also, it is possible for a party that has contracted for pipeline capacity to default on payments. Further, if gas prices are down at the time a contract for pipeline capacity expires, it is possible that the capacity would not be resubscribed and could remain idle for some time. As a result, some costs could go unrecovered.

### Operating Outages

The pipeline owner would be responsible for providing usable pipeline capacity with limited outages for maintenance and limited system failures. Outages due to "force majeure" (acts of God) would likely require customers to continue to pay for their capacity reservation despite the temporary interruption. Nonetheless, to the extent that the pipeline operation outages exceed the negotiated terms for allowable outages, revenues could be lost and returns negatively affected. System outages can occur from a variety of causes. These include equipment failure or lower than expected performance; management, information or process failure; labor or contract disputes; and catastrophic events. Extended outages could significantly lower revenues and returns for the pipeline owner.

### Regulatory Setbacks

The pipeline would be operated under the regulatory oversight and approval of FERC, NEB and numerous other national, state, provincial and local regulators. Through the associated regulatory process, decisions could be made that negatively affect the owner's ability to earn its authorized return. Risks of lower returns could result from decisions made within the existing regulatory framework, changes in regulatory requirements, and tariff and procedural interventions by third parties.

### Insurance Inadequacies

Because the Alaska Gas Pipeline would be so capital intensive, it is vital that it carry customary levels of property and liability insurance. However, there is no assurance that this insurance would be available, at least at affordable rates in the future. Inadequate insurance coverage could result in significant losses for the pipeline owner.

### Easement Conflicts

The pipeline would require that easement rights be acquired from thousands of landowners. In addition, it might have to acquire rights from First Nations groups in Canada. Even if easements and rights of way are obtained through standard legal processes, the risk would exist for legal conflicts and claims arising out of construction or operation of the pipeline.

## Projected Returns from State Investment in Pipeline

Financing of the Alaska Gas Pipeline is assumed to include a debt/equity ratio of about 70/30. The two sponsor groups evaluating pipelines from the North Slope to Alberta are projecting this capital structure, and the Alliance pipeline had this structure. With the 70/30 debt/equity ratio for the Alaska Gas Pipeline, debt cost is assumed to be 8 percent and the regulated return on equity is assumed to be 12 percent.

However, actual returns on equity could vary from planned levels. There is risk of lower return due to the risks outlined above. There is also a prospect of a higher return if the pipeline owner performs in a way necessary to achieve incentives that would likely be built into the tariff.

### Financial Model

To understand the range of possible returns from state ownership, a financial model was developed by the Department of Revenue's consultants. The primary focus of the model was to estimate the range of possible returns that could be earned from investment in the North Slope-to-Alberta pipeline given the various investment risks outlined above. The model also provides for analysis of variances in the tariff from different assumptions relating to taxes paid on returns to equity and debt components to invested capital.

However, the model was not developed to estimate the absolute tariff level. So, resulting tariff calculations should be considered as only general approximations. Further, no estimates were made of the cost to expand capacity out of Alberta to complete the transport of North Slope gas to final markets.

The model calculates annual revenue requirements and levelized tariffs necessary to meet those requirements over an assumed 25-year life of the pipeline. It then calculates the 25-year internal rate of return (IRR) based on application of the tariff and a range of projected actual operating results. The model also includes a tax component that calculates potential income tax benefits from state ownership.

The model estimates both rate base and a replacement cost new less depreciation (RCNLD) value of the pipeline for each year of the projected 25-year operating period. The rate base estimate is used to calculate annual return requirements based on the debt/equity ratio, debt costs and regulated equity returns discussed above. The RCNLD estimate is used to calculate annual property tax associated with the pipeline.

The model calculates revenue requirements in each year as the sum of operation and maintenance costs (including administration), depreciation, property tax, income tax and return on rate base (in terms of interest expense and return on equity). Capital, operation and maintenance costs were directly input based on estimates made by the sponsors evaluating the Alaska Highway Route. Depreciation was calculated based on straight-line, 25-year depreciation rate. Property taxes were calculated by applying an assumed tax rate of 2 percent (20 mills) to the RCNLD value of the pipeline in each year. Income taxes are discussed separately below.

In the model, the annual revenue requirement calculations are in turn used to calculate a levelized tariff per MMBtu. This tariff, when applied to the projected gas volumes, produces a cash flow that yields the same IRR as the projected 25-year revenue requirement. The tariff is calculated both in terms of nominal prices (including projected inflation) and in terms of real prices (2001 dollars). In the base case, it is assumed that federal income tax would be paid on all returns to invested capital. That is, it is assumed that interest paid on bonds issued to finance the project would be taxable and that the state's share of net income to the project would also be taxable. However, the model provides analysis of the degree to which the pipeline tariff would be lower with tax exemptions to these returns (see Income Tax Approach and Assumptions, below).

The model projects actual operating results under a number of different possible scenarios. These scenarios reflect both risks of achieving lower than regulated target returns and possibilities of higher than target returns from capitalizing on incentives assumed to be included in the tariff. Probabilities are assigned to a range of risk and incentive possibilities, and a set of Monte Carlo simulations of operating results are run. The results are compiled into an expected value and a risk profile (probabilistic range) of IRRs from ownership investment in the pipeline. The structure of the risk analysis is shown graphically in Appendix B.

### Income Tax Approach and Assumptions

If pipeline ownership is in the form of a single corporation with specific shares held by the individual owners, income taxes would be assessed before returns flow back to the owners. This would mean that return on the state's equity share would be taxed in the same way as that of the private owners. However, if ownership in the pipeline is in the form of a partnership or limited liability company, the possibility exists that the return to the state would not be taxed.

Income tax was calculated assuming that 50 percent of the pipeline investment and income generated from the investment would be within the United States (Alaska) and 50 percent would be within Canada. For the U.S. portion of the pipeline, a 9.4 percent state and a 35 percent federal income tax rate were assumed. Federal tax was calculated assuming a 1.5 times accelerated depreciation schedule over 15 years, with benefits of this tax treatment flowing through to the tariff. For returns generated in Canada, provincial tax rates were estimated to average 14 percent and the federal income tax rate was assumed to be 22 percent, based on official projections by the Canadian government. Canadian tax law recognizes depreciation costs as capital cost allowance (CCA). A 4 percent annual CCA is allowed on the declining value of pipelines. The CCA is 20 percent on general equipment and 30 percent on transportation and computer equipment. The weighted average for investment in the Alaska Gas Pipeline was estimated to be 5 percent for input to the financial model.

### Risk and Incentive Inputs

As outlined above, pipeline owners face risks and incentives that can affect returns on the owner's investment in the Alaska Gas Pipeline. Many of the risks were reflected in the financial model through the following inputs.

The risk of construction cost overruns was evaluated by assuming that there was a 40 percent chance of cost overruns. The size of overruns evaluated ranged from 15 to 30 percent. It is recognized that some of the cost overruns would be recoverable through a tariff adjustment; a range of 0 to 100 percent recovery was evaluated.

The chance of project abandonment or mothballing was assumed to be 3 percent.

Inadequate capacity subscription or customer default was addressed with three separate inputs. First, a 1 percent probability was input for the risk of a customer with reserved capacity being unable or unwilling to pay for his take-or-pay obligation because of contract disagreements or financial difficulty. The percent of pipeline capacity affected was evaluated at 5 to 30 percent. The number of years affected was evaluated at 1 to 6 years.

Second, the prospect of the pipeline not being fully subscribed by the time it begins operation was given a 5 percent chance. The percent of the pipeline capacity unsubscribed was assigned a 5 to 10 percent probability, and the number of years affected was evaluated at 1 to 5 years.

Third, insufficient demand for pipeline capacity when individual capacity reservation contracts expire was evaluated at a 5 percent probability. The expiration of contracts was evaluated at years 10 to 25, and the percent of capacity left unused as a result was evaluated at 10 to 25 percent.

Operating outages were evaluated for both chronic above-plan outage levels and for a one-time catastrophic event. Chronic outages were assumed to have a 10 percent chance, with uncompensated downtime running from 2.5 to 5 percent. The chance of a one-time catastrophic failure was evaluated at a 2 percent chance. The one-time event was given an equal chance of occurring in any of the 25 years in the analysis period.

It was assumed that the owner would have an incentive to share in the benefit of cost savings during construction. The owner realizing shared-savings was evaluated assuming there was at a 10 percent chance of a 10 percent cost underrun, and that the owner would share 25 percent of the savings.

## Estimated Returns

Applying the above assumption, the model shows that the expected IRR value for ownership investment in the Alaska Gas Pipeline is 8.1 percent to total capitalization and 10.1 to equity. For equity, this is 1.9 percentage points lower than the assumed regulated rate of return. The range of returns to total capitalization is from 7.1 percent at the 10th percentile to 8.8 percent at the 90th percentile, while the range of returns to equity is from 5.8 percent at the 10th percentile to 12.0 at the 90th percentile.

These ranges are shown in risk profiles presented in Figures 7-1 and 7-2, respectively. The risk profile shown in these figures is a graph of the probability that returns would be at or lower than the levels listed on the X-axis of the chart. Not reflected in these profiles is the chance that the state could actually lose money through the pipeline investment. This would happen if the state invested capital only to have the pipeline not be completed. The chances of such an occurrence are unknown. However, as noted above, this possibility was assigned a probability of 3 percent for the purposes of this analysis.

**Figure 7-1**
**Probabilistic Range of Returns to Total Capital Invested in the Alaska Gas Pipeline**

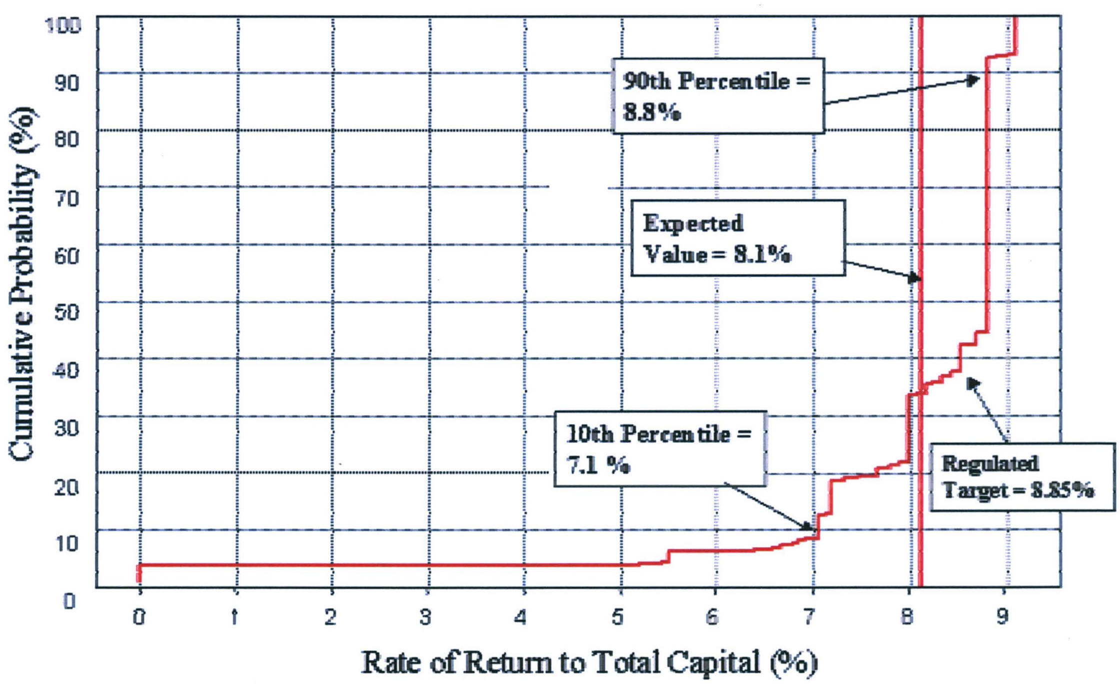
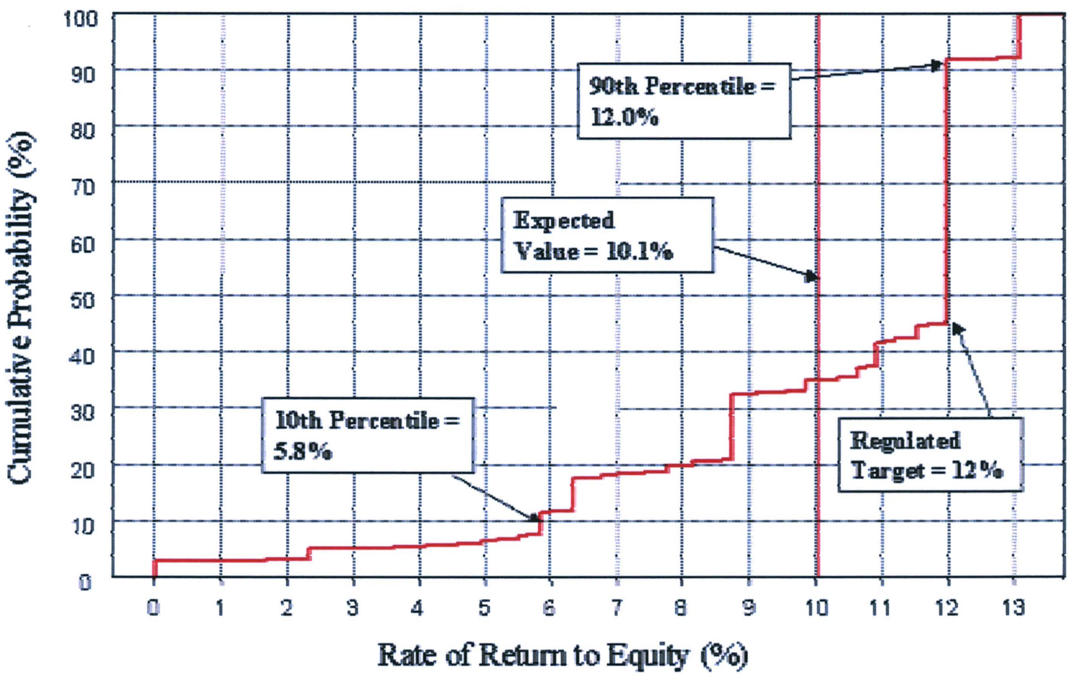


**Figure 7-2**
**Probabilistic Range of Returns to Equity Invested in the Alaska Gas Pipeline**




Possible returns on equity are presented for various levels of ownership participation and probabilities in Table 7-1. These estimates are based on a projected debt equity ratio of 70/30.

**TABLE 7-1**
Alaska Gas Pipeline
Probable Returns to Equity Investment

| | | | | Return to Equity | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Percent Return | | | Avg. Annual Return (Millions of 2001$) | | |
| Ownership Level | Capital Structure (Millions of 2001$) Debt | Equity | Total | Expected Value | 10th Percentile | 90th Percentile | Expected Value | 10th Percentile | 90th Percentile |
| 12.5% | 1,085 | 465 | 1,550 | 10.1% | 5.8% | 12.0% | 52 | 36 | 59 |
| 25.0% | 2,170 | 930 | 3,100 | 10.1% | 5.8% | 12.0% | 103 | 71 | 119 |
| 50.0% | 4,340 | 1,860 | 6,199 | 10.1% | 5.8% | 12.0% | 206 | 143 | 237 |
| 100.0% | 8,679 | 3,720 | 12,399 | 10.1% | 5.8% | 12.0% | 413 | 285 | 474 |

Base inputs to the model were developed on the assumption that all returns to invested capital would be subject to federal corporate income tax. However, in separate computer runs, the financial model was also used to calculate tariff reductions that could be achieved if project owners were 100 percent exempt from federal income tax. This included separate analyses for federal income tax on returns to equity (profit) and on interest associated with debt used to finance the pipeline. For that analysis, a 70/30 debt-equity ratio was assumed.

The analysis showed that tariffs would be about 8 percent lower if the project owner or owners were exempt from federal income taxes on 100 percent of the return to equity. If bonds issued to finance the debt portion also were tax exempt, it was assumed that the interest rate on the bonds would be 5.6 percent rather than the 7.5 percent in the base analysis for taxable debt. This analysis showed that tax-exempt bond financing would lower the pipeline tariff by an additional 10 percent. So, if the project were able to avoid federal income tax on its profits and was financed with tax-exempt debt, the pipeline tariff would be a combined 18 percent lower than under fully taxable ownership.

If the tax exemptions applied only to a 12.5 percent state ownership share of the pipeline, the overall effect on reducing the tariff would be just 2.2 percent.

Given the speculative nature of such cost savings and ownership arrangements, the method for allocating these cost saving (in a separate tariff for the state or as a reduction in the common tariff for all customers) was not considered in this report.

Sample printouts of model input and output are provided in Appendix C.

## Ownership of Pipeline Capacity Rights

In lieu of an equity investment in the Alaska Gas Pipeline, or in conjunction with an investment in the project, some proponents have asked whether the state should acquire pipeline capacity rights. The state could acquire capacity rights by making a contractual commitment for firm capacity. This commitment would likely consist of a long term (15 or 25 years) binding obligation to ship or pay for the capacity. The ship-or-pay obligation would probably be in the form of a fixed-demand charge for the obligated capacity. Because almost all of the owner's costs would be fixed, almost all of the revenues generated from the tariff would be through the fixed-demand charge. There would also likely be a nominal commodity charge per thousand cubic feet (mcf) of transported gas to cover the owner's variable costs (costs that vary according to volumes transported through the pipeline).

Although the process for allocating pipeline capacity rights under ANGTA is uncertain, it is assumed they would ultimately be sold through an open-season process. Because pipeline owners need early commitments to demonstrate project need to regulators and to manage their own risks and obtain any necessary project financing, the open season, and hence the state's commitment to pay for its capacity share, would occur before final planning and permitting activities and pipeline construction.

Once the pipeline is constructed and operating, the state could use its capacity in either or both of two ways. First, the state could use its capacity to move its own gas taken as in-kind royalty. It could sell the gas in Alberta or pay for other pipelines to further transport the gas to market in the Lower 48 or Canada. Second, the state could resell pipeline capacity rights to others that have gas to transport. The price for this service could vary above or below the tariff the state pays for the capacity rights.

## Risks of Capacity Ownership

Risks associated with state purchase of capacity rights on the Alaska Gas Pipeline are described below for each of the two potential uses of the capacity: transport of the state's gas if the state takes its royalty share on an in-kind basis, and resale of capacity rights for gas transportation by others.

### Transport of State Gas

The state has the option to take its royalty share on either a value[37] or in-kind basis; the state can shift between these two bases on six months' notice. If the state takes its royalty share on an in-kind basis, it may do so with the intent of realizing higher value than it would by simply taking its royalty share on a value basis. Purchasing capacity rights on the pipeline would be a logical first step to achieve this objective.[38] As noted above, obtaining such

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[37] Based on state law (AS 38.05.180) and lease agreements, the royalty gas value is based on the value of pipeline-quality gas ready for transport from the North Slope under the terms of some of the leases.

[38] Taking the state's royalty share in kind without proportionate reserved capacity on the pipeline might create undue risks that the state could either not get its gas to market or be forced to do so at a relatively high cost and resulting relatively low return. This is because there will be substantial gas production and treatment capability on the North Slope that will likely keep the pipeline filled; those without pipeline capacity rights would be shut out or forced to pay high rates to gain access. This risk is eliminated, of course, if the royalty-in-kind purchaser has its own reserved capacity.

capacity rights would require a long-term commitment (15 years or more) to take or pay for the reserved pipeline capacity. Taking royalty in-kind does not require the state to nominate capacity if the buyer nominates its own capacity or uses the gas on the North Slope.

While the intent would be to earn higher returns, taking its royalty share in-kind—together with purchase of pipeline capacity rights—creates additional costs and risks for the state relative to taking its royalty share in-value. These costs and risks include the following:

1. Costs incurred to market the gas.
2. The risk of absorbing losses from high costs or poor market conditions.
3. The risk of paying for capacity even during extended outages caused by force majeure.
4. The risk of not realizing as high market prices as the gas producers and therefore earning less than if the state were to take its royalty share on a value basis.

Each of these costs and risks is discussed in more detail below.

The primary benefit of taking the state's royalty share on an in-kind basis with purchase of pipeline capacity rights is that it could ensure that the state's proceeds are based on the true market value of the gas. That is, it avoids the risk that the royalty share, when taken on a value basis, could be calculated at an artificially low value.[39] Losses to the state from royalties calculated on an artificially low market price can easily exceed the extra costs and risks associated with taking the state's royalty share on an in-kind basis.

The following subsections discuss each of these four extra costs and the risks associated with taking the state's royalty share on an in-kind basis with purchase of pipeline capacity rights.

### *Gas Marketing Costs*

The state's costs to market the gas in a downstream market is an extra cost the state would bear with its royalty share taken in-kind. It would likely include the cost of establishing a

39 The general basis for the calculation of value when royalties are taken on a value basis will be the higher of value delivered to market or the proceeds received less transportation costs. Market value will likely be determined from sales prices at market hubs. This might be in Alberta (e.g., AECO) or closer to its actual end use, with prices at a number of hubs in the Lower 48 states and in Canada used to calculate market value. The transportation costs will, at a minimum, be the cost of delivering North Slope gas across the Alaska gas pipeline to Alberta. If market value is established closer to market, transportation in other pipelines will also be included in the calculation.

state agency or paying a third party to market the gas and include some administrative costs to oversee the operation.

Management of the marketing process from the wellhead to the burner-tip is a sophisticated process requiring quick decisions implementing a well-conceived marketing strategy. It requires, among other things, the use of short- and long-term positions, various derivative products, and strict adherence to marketing and trading policies. Although the state could contract for a marketing service or develop the expertise in-house, the learning curve is steep and seemingly trivial decisions can have substantial financial and legal consequences.

***Risk of Absorbing Losses from High Costs or Poor Market Conditions***

Owning pipeline capacity rights and taking royalty share in-kind creates a risk that the state could realize a negative net value for its gas—which could happen if the Alaska Gas Pipeline tariff were higher than the value of gas delivered to Alberta. This could occur due to high pipeline costs or poor gas market conditions. Higher-than-expected tariffs could result from pipeline cost overruns. As described above, such overruns would likely be rolled into the tariff as long as they were not shown to result from imprudent management decisions. Lower-than-expected gas prices could result from poor market conditions. If adequate pipeline capacity to ship gas out of Alberta does not develop, the resulting oversupply in Alberta and the limited access to downstream markets would drive prices for Alberta gas prices to abnormally low levels. Low prices could also occur if new gas supplies and/or low demand in North America at least temporarily drive prices to levels that are lower than the transportation costs to deliver gas to market.

This risk does not apply to the option of taking the state's royalty share on a value basis. If the same poor market conditions were to occur under this option, the netback value to the producers would be negative. However, the state would likely simply receive no royalties rather than a loss. It is our understanding that the state would not be liable for a negative royalty payment from the producers' losses. Rather, it is assumed that the royalty would be waived or set at zero.

***Force Majeure Risk***

As discussed above in the subsection on Pipeline Ownership Risks, owners of pipeline capacity rights may be required to continue to pay for their capacity reservation during periods of pipeline service interruption caused by acts of God. These could include interruptions due to events that are beyond the control of the pipeline owner (e.g., natural disasters, fires, explosions, terrorist acts, other sabotage and other catastrophes). If the state purchases capacity rights on the pipeline to market royalty gas, it runs the risk of continuing to pay during force majeure events. Such risks are avoided when royalty is taken on a value basis. (In any case, state royalty revenues would be interrupted if North Slope gas deliveries were interrupted—regardless whether gas were taken on a value or an in-kind basis.)

***Realized Market Price Risk***

Because gas producers have substantial expertise in marketing their products, they are likely to receive maximum value for their sales of North Slope gas. If the state were to take its gas on an in-kind basis and market it in downstream markets, it would probably have to establish a gas marketing agency and staff it with industry experts. Nonetheless, because marketing of wholesale petroleum products is not a core business of the state, there is some risk that it would not realize as high of a value in its sales as would the producers. All other things being equal, this would result in lower royalty value accruing to the state than if it were to take its royalty share on a value basis. On the other hand, there is a potentially significant opposite risk, that the calculated royalty share, when taken on a value basis, could be artificially low, possibly lower than the value achieved by taking the state's royalty on an in-kind basis.

**Resale of Pipeline Capacity Rights**

The state could take the risk of marketing its reserved capacity on the pipeline to others that have a need to transport gas to market. This could include existing oil and gas producers, as well as entities that might discover and produce gas in the future. To the extent that the state could sell, or release, its capacity rights for a higher price than the fixed charge it would be obligated to pay, plus its administrative costs, it would profit. In the opposite direction, the state would lose money if it could not cover these costs in its resale of capacity rights.

It has been suggested that the state might purchase capacity on the pipeline specifically to make capacity available so that future new production would have access to markets through the pipeline. The logic is that this would increase production and, with it, state royalty and tax revenues. However, to the extent that the pipeline would be full with production from existing wells, the state would already be benefiting from full production to fill the pipeline.

Once pipeline capacity opened up after production declines from existing wells, it would become available for new production. Therefore, the state does not have much to gain from risks associated with purchasing pipeline capacity rights for resale if it is indifferent to whose gas fills up the pipeline. This is not necessarily the case, however. There will be little exploration for gas for decades if those that would explore cannot get the gas they find into the pipeline. A diversified group of gas producers is desirable to the state, as is exploration and development in new areas in the state.

## Returns from Capacity Ownership

Purchase of capacity rights have higher risks and potential returns than investment in a share of the pipeline itself. Returns are much less certain than the regulated return from pipeline ownership. The North Slope gas producers recognize this higher risk in establishing a "hurdle rate" of return for their projected cost for treating and transporting their gas. In their feasibility studies, the producers will probably require a relatively high rate of return on all investments they make in treating and transporting gas through the Alaska gas pipeline. Most of this risk consists of the fixed commitment to pipeline capacity.

As noted above, returns from capacity purchases made to market state royalty gas need to be assessed in terms of the state's ability to realize higher value than that calculated under a royalty value formula. Any extra value obtained from use of the pipeline to market royalty gas must be sufficient to cover the cost to market the gas, the risks of absorbing losses during poor market conditions, improper management decisions and force majeure events, and the risk that the state cannot market gas as well as the producers.

The potential for added or reduced overall returns to the state from purchase of pipeline capacity rights cannot be estimated until:

1. The precise method is determined for calculating the value of the state's royalty share. It is entitled to the higher of market value or sales proceeds.
2. The cost to market gas taken on an in-kind basis is estimated.

3. The estimated Alaska Gas Pipeline tariff is known and assessed against the prospects for poor market conditions, particularly as they relate to North America market access from Alberta.

4. The state's ability to market gas supplies relative to the producers' ability is assessed. State officials acknowledge that the state should never expect to be as skilled in marketing gas as those in the business.

Once these uncertainties are clarified, the state would be better able to assess the potential return from investing in capacity rights and taking its royalty payment on an in-kind basis.

Purchase of pipeline capacity for resale would be a speculative venture. Returns from pipeline capacity purchase for resale would depend on the state's ability to resell the capacity at a higher price than its tariff cost, plus the cost of administering the resale program. As noted above, it is not likely that purchase of pipeline capacity to hold for others would increase gas production and thereby increase state royalties. Therefore, the direct return from a pipeline capacity purchase for resale would simply be a function of the state's ability to resell the capacity at a higher level than its costs.

# Effect on State Cash Flow

If the state were to purchase an ownership share in the pipeline equal to its royalty share of 12.5 percent, and assuming a debt/equity ratio of 70/30 and a $12.5 billion total project cost, the state's equity investment would be $465 million (2001 dollars). Equity contributions at higher ownership levels are shown in Table 7-1.

As noted above, with the risk assumptions made for this analysis, the expected rate of return on equity invested in the pipeline is projected to be 10.1 percent, with a 10 to 90 percentile range of 5.8 to 12.0 percent.

Investment of this capital in the pipeline would require a delay in realized returns. The state's obligation to advance cash for its equity investment would begin as soon as its purchase of an ownership share was complete. These payments would begin at relatively low levels as planning and engineering are completed, then increase to higher levels during actual pipeline construction. The pipeline would not start generating revenues until operations begin. We have assumed that the earliest pipeline operations could start is 2009. The state's return on the equity it invested during planning and construction would be capitalized and rolled into the overall project capital base as part of "allowance for funds used during construction" (AFUDC). AFUDC would become part of the investment upon which the state and other pipeline investors would earn their return. Accordingly, between 2002 and 2008, the Permanent Fund, Earnings Reserve Account or other state funding source would be drawn down by the state's investment in the pipeline. This would total an estimated $465 million (under the assumptions stated above), of which $338 million would be direct investment from a state funding source, and $127 million would be in the form of AFUDC.

If the Permanent Fund (including the Earnings Reserve Account) was the source of funds, the investment would reduce Permanent Fund dividends by an estimated cumulative total of perhaps $60 or so by 2010. This reduction would be repaid in future years through earnings on the AFUDC component of the state's investment.

Ownership of capacity rights on the pipeline would have little effect on state cash flow under normal operating conditions. This is because costs incurred from monthly take-or-pay payments would be directly offset from sales revenues. Assuming that the capacity rights were being used to transport Alaska royalty gas to market for sale, revenues produced from gas sales would cover the cost of capacity rights. The risks to this normal cash flow are discussed above. Under the worst of the risk scenarios a force majeure event could occur, interrupting pipeline operations while the state is required to continue making its capacity payments. Under those circumstances, 12.5 percent ownership of the pipeline would reduce the state's overall cash flow by an estimated $21 million per month.

SECTION 8

# Effect on State of Alaska from Pipeline Investment

This section evaluates the effects that financial participation in the Alaska Gas Pipeline would have on the state's financial integrity, creditworthiness and ability to pay for essential public services. Any damage to the state's financial integrity and creditworthiness would lessen its ability to finance projects for public services. This section also evaluates several non-financial issues, such as state involvement in pipeline management.

## Effect on the State's Financial Integrity and Creditworthiness

A factor the state should consider in determining the manner in which it may participate in the project is the effect its participation would have on its financial integrity and creditworthiness. The state's overall financial integrity and creditworthiness is best measured by the credit rating assigned to its general obligation debt by agencies that rate debt as part of the lending process for public bond offerings. Three prominent rating agencies are Moody's, Standard & Poor's and Fitch.

Having a solid credit rating is a valuable benefit to the state, especially in times of fiscal uncertainty. Further, the state's credit rating indirectly inures to the benefit of or detracts from the rates that Alaska municipalities have to pay on their own debt.

The state itself has no outstanding general obligation debt, so the credit rating agencies have not re-evaluated Alaska's full rating recently. However, Alaska's most recent general obligation bond sale was rated at the high end of the ratings scale.

If the state were to participate financially in the gasline project, the rating agencies—in setting new rates for State of Alaska debt—would take into account several factors, including: (1) the form of the state's participation; (2) the feasibility and economic viability of the project and the likelihood of its completion; (3) the estimated increase in state revenues generated by the project; (4) the effect of the project on the state's overall economy; and (5) the timing of the benefits and costs to the state.

As discussed in Section 4, a small amount of equity or debt currently could be made available to the gasline project without damage to the state's current credit ratings. However, a multibillion-dollar capital investment funded by state debt that would be sufficient to gain majority control or a major influence in the project would likely have an uncertain, if not immediately negative, effect on the state's credit ratings. This would be the case for several reasons, including the fact that the project is not a typical governmental investment (in public infrastructure, *e.g.,* highways, prisons, etc.).

In addition, the debt would represent a governmental investment of unprecedented concentration in resource extraction, an industry with a history of substantial price volatility. Unless major adjustments were made in the state's operations and anticipated capital expenditures, it is probable that such investment would have to be funded by a very substantial amount of new general obligation debt, revenue bonds or creative use of sources of equity. The result would be increasing the state's indebtedness with respect to standard yardsticks such as population, resources and economic indicators.

Finally, the returns to the state would be over the long term. And, particularly in the near term when the project is just starting operations, these returns would not be assured.

# Importance of the State's Credit Rating

The state has good reason to maintain a solid credit rating. A downgrade of the state's rating would have direct and indirect financial consequences and, although harder to quantify, would create political problems between the state and its municipalities.

A reduction in the state's credit rating would result directly in higher borrowing costs each time the state entered the credit markets. This is true both for certificates of participation and general obligation debt. Higher debt costs would reduce the amount of money the state could borrow for public service projects. That is, the more money that is paid out in higher interest rates, the less money the state could borrow for the actual projects. This potential effect is discussed below.

The various state corporate entities (Alaska Housing Finance Corporation, AIDEA, Alaska Municipal Bond Bank Authority, Alaska Student Loan Corporation) that enter the debt market would also likely face higher borrowing costs. For those entities that contract with banks for additional credit support, the costs of bank lines and letters of credit would be more expensive. Furthermore, the state's strong credit position, as well as its substantial cash reserves, indirectly enhance the credit of municipalities throughout the state.

The higher borrowing costs would be evident not only in higher interest rates but also higher costs of bond insurance, further reducing the state's ability to raise as much money as it may want for public service projects.

And although of lesser direct effect to the state, the holders of state debt would see the value of their investments in the state diminish in value because a lower debt rating would reduce the value of state debt in the hands of existing bondholders.

The cost of a full step downgrade of the state's credit from the strong AA level to a strong single A level—while difficult to estimate—would be significant. A downgrade of the state's rating would ripple through all of the governmental units of the state, likely resulting in across-the-board downgrades. Ultimately, this would affect all of the state's $6.5 billion in outstanding bond debt, particularly as bonds matured and new bonds were issued.

Over the past 10 years the difference or spread between AA and A rates have averaged 16 basis points. While this is a good starting point to determine how much the cost of capital would rise after a downgrade, there is a larger story to tell. Until the early '90s, the state historically paid an "Alaskan penalty" on its bonds that ranged from 15 to 50 basis points. The market assessed this excess cost because of the distance of the state from the financial markets, lack of information and the isolation of the state's economy. The current high ratings of the state are the result of consistent performance of the state and its economy, and the prevalent perception that Alaska has significant resources available. A downgrade, however, would be a major event that could very well bring back the penalty for Alaska issuers.

Finally, Alaska is a "non-specialty state," meaning there is a small population and no tax benefit to in-state investors of tax-exempt bonds because there is no state personal income tax. Therefore, the state relies very heavily on investors outside the state to purchase bonds, and a downgrade could hurt Alaska more heavily than it would a state with a larger population and state income tax.

In sum, the cumulative effect of these considerations if the state were downgraded from AA to A would likely be in the 25 to 40 basis points range. This increased cost of capital would result in an additional $250,000 to $400,000 in interest expense per year for every additional $100 million borrowed. Assuming a rolling level of debt at $6.5 billion, a downgrade could eventually cost between $16.25 million and $26 million annually.

## Balancing State Benefits and Costs

The financial analysis above leads the Department of Revenue to conclude that a monetary equity investment in the Alaska Gas Pipeline would likely provide the state with a positive return on investment over the long term. The sources of state funds are limited, however, and likely would need to be raised through the issuance of some form of debt—which would present its own set of financial problems as discussed in detail above.

However, just because the state *can* invest on some modest level does not mean that the state *should* invest. In addition to the strictly financial issues, there are numerous practical aspects to the investment discussed below.

- Of some importance to the state in contemplating an equity or debt investment is the substantial risk it would entail if the state invests in the project as a business partner. Unlike a major oil company or integrated natural gas pipeline, the state has little capability to monitor or control those risks and does not have the financial strength to absorb large capital or operating losses. It would be different, however, if the state were simply a shareholder in a corporation that owned the Alaska Gas Pipeline. As a shareholder, the state would be shielded from any liability. The only risk would then be the stock price.

- If Alaska were to become an active participant in the enterprise as an equity investor, it would be required to advance funds almost immediately to buy into a sponsor partnership to gain the same rights as other equity investors. Thereafter, the state would be required to meet continuing capital calls. Therefore, Alaska would need to have readily available funds for this purpose or make borrowing arrangements to make money available now and continuing for the next several years of construction. Both of these options would substantially infringe upon the state's flexibility to meet public service needs. Given the magnitude of the state's anticipated needs for public services, the policy and constitutional limits on the state's available funds, and the ongoing revenue shrinkage due to declining North Slope oil production, there would appear to be little room for such a financial commitment.

- Superficially, one might conclude that any equity ownership would give the state a degree of control over management of the Alaska Gas Pipeline system, including a control over major policy decisions—such as retention of gas or gas liquids for in-state use—which could not be obtained in other ways. However, it is highly unlikely that the existing ANGTS sponsors or producers group would be willing to make a significant amount of equity available to the state. We understand that various parties in one consortia already are seeking higher ownership percentages; other third parties are interested in joining the consortia; and many companies do not want the state as a business partner. Accordingly, there is a "sellers market." In this circumstance the sponsors would be dictating the terms of the state's investment, and the state would likely have very little negotiating leverage. Thus, as a partner, the state probably would become just a minority participant with limited, if any, management rights. The amount of information shared with the state probably also would be restricted. The state's interests are likely to differ in important respects from the sponsors, so that it frequently would be outvoted in the event of a dispute.

- As a participant in the Alaska Gas Pipeline, Alaska might magnify the conflict between its interest as a regulator of the project in its sovereign capacity and its already existing economic interest in the project as both a royalty holder and a taxing authority. There also would be a conflict between the state's duties to its citizens as a regulatory and taxing agency and the fiduciary obligations of the state as an equity partner to the other project partners. It has been suggested that the use of a separate state-established corporation or authority as an investment vehicle would mitigate this conflict. While the interposition of a separate governing board certainly would help to mitigate the conflict, ultimate authority and control over the participation of the state in the enterprise would remain with the legislature and the governor.

- There is precedent in times of national emergency and wartime conditions for governments to become involved in the development, construction and ownership of pipelines.[40] Absent such extraordinary circumstances, public sector investment in pipeline projects is not customary in the United States. The Department of Revenue and its consultants were unable to find a single material natural gas pipeline project in North America today where a state or federal government entity was a participant. There still remain a few examples associated with Canadian provinces, however the trend is for privatization of those investments. There is precedent internationally for such governmental investments, but usually those circumstances are dictated by tradition, national security issues, World Bank financing requirements, or the inability to get the project developed any other way. None of those situations are applicable to this project.

[40] The classic example is the federal government's involvement in the construction of the "Big Inch" oil pipeline from the Gulf Coast to the East Coast in World War II.

SECTION 9

# Effect of State Participation on Project Success

This section discusses examines whether state participation as an equity or debt holder might help or hinder completion and operation of the project. This obviously is an important consideration for the state. Anything done to improve or hinder gas royalty income would have a measurable effect on the state's cash flow.

## Interest of the Pipeline Sponsors

Among the issues discussed with the companies interviewed was how they viewed having the state as a partner and whether they saw the state as adding value to the project design, development, construction and operation process. As mentioned previously, for a variety of reasons the companies were not in favor of the state as a partner. At best, several of them thought the state would not materially aid implementation or operation of the project and, at worst, some thought the state's involvement would be a negative factor .

Those that believe the state's participation would impede progress of the pipeline said they were concerned about the state politicizing and slowing the multitude of decisions that must be expeditiously made—especially in route selection, marketing, procurement and selection of contractors. Although not critical of the quality of the state's personnel, the companies were concerned that the state simply lacked expertise in commercial enterprise activities and was not accustomed to making business decisions at the pace required by the project. Further, they were concerned that the state's presence in the project would needlessly interfere with or add layers of confusion to the complex financing program that would be required by some of the project sponsors. The requirements of the state and the requirements of the lenders vis-à-vis the state in the financing process might be incompatible and mutually burdensome.

# Critical Success Factors

Industry's concern is borne out by an examination of the important factors that would be critical to the success of the initial phase of the project. These include the requirements for:

- Shipper contracts
- Pipeline design
- Federal, state and provincial approvals
- Construction permits
- Right-of-way and land use permits
- Off-take agreements
- Engineering, procurement and construction contracts
- Financing

The state would have little effect on the successful outcome of these requirements, except in expediting state right-of-way approvals, obtaining state and local permits and, if it so chose, to contract for the shipment of its royalty gas. The execution of most of these critical success issues are solely within the province of the Alaska Gas Pipeline. Most of the potential sponsors have had substantial experience with addressing these issues in the development and construction of natural gas pipelines throughout the world.

The state would not have any effect on the two most critical factors to the success of the project over the long term: the market for the natural gas and construction costs. The size of the natural gas market in Alaska is very limited. The marketplace will be the Lower 48, an intricate energy market with which Alaska has no commercial experience. Further, there is little the state could do to assist in the gas pipeline engineering and construction decision and implementation process. This simply is not a core competency of the state.

Supplying $300 million to $500 million of state funding really would not significantly assist the potential project sponsors, given their sizes and capabilities. In fact, the size of probable state funding likely would not be much different that the size of the project contingency factors built into the potential sponsors' economic modeling. So, from a financial point of view, the state's participation would be immaterial.

As discussed in Section 6, the North American natural gas landscape has been significantly changed over the 25 years a North Slope natural gas pipeline has been under consideration. Although the pipeline companies involved in the late 1970s and early 1980s were large, they still needed to seek outside capital sources, such as the state, to help fund the project. Today, with the wave of mergers and consolidations sweeping the oil and gas producer and pipeline industries, the major players interested in developing the gasline are much larger and much more sophisticated. Of the 10 companies interviewed for this report, the smallest, Alberta Energy, had an enterprise value of $8.4 billion; the largest, ExxonMobil, about $266 billion. (And the mergers continue: Alberta Energy on January 25, 2002, confirmed reports it will merge with rival PanCanadian Energy Corporation to create what could be Canada's largest oil and natural gas company with a market capitalization of approximately $19 billion.)

Several of the companies interviewed are so large—as shown in Table 9-1—that they said they did not intend to borrow to finance their share of the $10 billion to $18 billion project cost, but merely intended to "write a check" off their balance sheet.

**TABLE 9-1**

Enterprise Value of Oil and Gas and Pipeline Companies

| Company | Enterprise Value ($MM) |
|---|---:|
| ExxonMobil | 265,706 |
| BP | 184,556 |
| Duke | 44,964 |
| El Paso | 40,808 |
| Williams | 23,523 |
| TransCanada | 22,505 |
| Phillips | 20,937 |
| Anadarko | 18,116 |
| WestCoast | 10,463 |
| Alberta Energy | 8,433 |

Enterprise Value = Market Value + Debt + Preferred Stock Value + Minority Interest - Net Working Capital

The size and sophistication of the industry and the size and complexity of the project give rise to several important realities Alaskans should consider in making the judgment whether to make an equity or other financial investment in a North Slope pipeline project.

If the state could provide a means for tax-exempt debt financing of the project, it might improve the economic feasibility of the project and therefore increase the chances the project is actually constructed.

SECTION 10

# Conclusions

Based on information developed in this report, the Department of Revenue's consultants offer the following conclusions about state financial participation in the Alaska Gas Pipeline:

**1)** Even if state ownership were restricted to just pipeline facilities, full ownership of the Alaska Highway Route pipeline would require $9 billion to $10 billion (2001 dollars) for construction. Deferred returns to capital invested during the estimated seven years before the project is likely to be completed would bring the total estimated pipeline investment to $13 billion to $14 billion. (These deferred returns are referred to as Allowance for Funds Used During Construction, discussed in Section 7 of this report.)

**2)** Without legislative action, the state does not have a ready source of cash for such a large investment. This is true even if the state were to limit its investment to 12.5 percent, an ownership equal to its royalty share of North Slope natural gas. Even at that reduced ownership level, the state's share of the total project investment could be as much as $1.75 billion (12.5 percent of $13 billion to $14 billion).

**3)** The state could make a significant investment if the legislature changed state law to direct the Permanent Fund to write a check. A 12.5 percent investment in the pipeline, assuming it was all equity and no debt, would take about 7 percent of the Permanent Fund. Even if the investment were 30 percent equity and 70 percent debt, the equity investment would still take more than 2 percent of the Permanent Fund's market value — making it the single largest holding of the fund. This large of an investment in a single entity, with the risks discussed in this report, might well violate the Prudent Expert Rule in state law governing Permanent Fund investment decisions. Additionally, about 80 percent of the state's unrestricted general purpose revenue currently is derived from oil and gas taxes and royalties. Permanent Fund investment in the pipeline would exacerbate the state's heavy reliance on one industry.

4) The legislature could appropriate money from the Earnings Reserve Account of the Permanent Fund to a state agency or other corporation to make the actual pipeline investment, thereby avoiding the issue of what is a permissible Permanent Fund investment. However, the Earnings Reserve Account is the Permanent Fund's sole method of absorbing market volatility, and any significant withdrawal from the account would jeopardize Permanent Fund dividends and inflation proofing.

5) The Alaska Constitution does not allow general obligation bonds to finance state participation in a joint business venture. This would limit the state to financing and owning 100 percent of the project. Further, such a major issuance of general obligation bonds or other state-supported debt would compromise the state's creditworthiness and, as a result, reduce its credit rating. At the state's current level of indebtedness, a downgrade from an AA to an A rating could increase the state's overall borrowing costs by an estimated $16 million or more per year. The state's ability to finance other public services also would be compromised. In addition, a reduction in the state's creditworthiness would likely have a negative, cascading effect on municipalities and other public agencies in Alaska.

6) The most plausible source of state participation through debt funding would be the issuance of taxable revenue bonds, secured for example by ship-or-pay contracts with the North Slope gas producers. However, the feasible size of such an issuance is uncertain. State issuance of bonds large enough to finance 70 percent of a 12.5 percent share of the pipeline (approximately $1.2 billion) would place the state in uncharted waters. Although ship-or-pay contracts with the producers should provide good security for the bonds, the large size of the debt relative to any previous State of Alaska revenue bond issuance, the manner and nature of the use of the bond proceeds, financial market pricing and repayment security requirements raise novel issues in the context of an Alaska gasline.

7) It theoretically would be possible for the state to sponsor a private corporation of Alaska investors to participate in the project. However, there are myriad practical, legal and public policy issues that need further review, including the source of investment funds, the qualifications for investors, tax implications, management of the entity,

constitutional matters and administration of the program. More importantly, it is difficult to understand how this proposal would provide any material improvement over any other available source of gasline investment capital. It appears to introduce yet another layer of complexity to an already difficult situation.

**8)** The largest risk associated with investment in the pipeline is that it would not be completed. In that case, the state's investment would be lost. Assuming the project would be completed, return on the state's investment would be regulated by the Federal Energy Regulatory Commission in the United States and the National Energy Board in Canada, and would likely result in a return consistent with or higher than state investment guidelines. Assuming a FERC/NEB-approved target return to equity of 12 percent, the state could expect to earn an average return to equity of about 10 percent. Probability analysis shows that average returns to equity over the life of the pipeline could range from 5.8 percent at the $10^{th}$ percentile to 12 percent at the $90^{th}$ percentile. Returns on the debt portion of the state's investment, however, would be limited only to the associated interest rate on that debt.

**9)** Pipeline ownership does not automatically provide the owner with capacity to ship gas on the pipeline. Capacity to transport gas would need to be separately purchased though an open-season process.

**10)** The state's need to purchase pipeline capacity rights to transport gas is dependent upon whether the state decides to take its 12.5 percent royalty share of North Slope gas on an in-value or in-kind basis. Pipeline capacity purchase might be prudent if the state decides to take its royalty share on an in-kind basis, in that it would assure the state of capacity to transport its gas to market. Otherwise, purchase of pipeline capacity would be speculative. Since the pipeline is likely to be full from its outset, purchase of capacity to provide a pathway for future discoveries would not increase total North Slope gas production or royalties paid to the state.

**11)** The primary benefits of establishing a state-owned public corporation or authority to construct and operate the pipeline are in the legal ability to assist state ownership and financing of the project. Such establishment could also reduce the conflicts of interest that might otherwise exist from direct state ownership. Separating the ownership into a semi-autonomous function could at least attempt to build a barrier between the state's responsibility to regulate the pipeline and its interest in maximizing return to its investment. However, it is unlikely that a state-owned corporation or authority would reduce pipeline costs. Without a specific exemption from the private-activity restrictions in federal tax laws, neither the state nor a state-owned corporation or authority would be able to issue tax-exempt debt to finance the pipeline.

**12)** It is unlikely that the state could provide any loan guarantees to other investors in the pipeline. The Alaska Constitution prohibits the state from "lending its credit directly to benefit a private entity." Regardless of the state's ability to do so, it appears there is little to no interest among prospective private pipeline sponsors for the state's participation in the project's financing, unless it could be tax-exempt. Therefore it appears that providing state loan guarantees or taxable debt would not aid project feasibility.

**13)** State ownership would not likely improve the feasibility of the project or be valued by private-sector project sponsors. There was a general consensus among industry representatives interviewed that a public/private ownership relationship with the state either would not help or would be a hindrance to the project. Reasons given include the following: State politics could impede and otherwise compromise the decision-making process; pipeline ownership and operation is not within the core mission or competencies of the state; state decisions would be complicated by its dual role as owner and regulator (even if mitigated by a state-owned, semi-autonomous entity); and general differences between public and private goals and cultures would detract from the decision-making process. These factors would create additional risk for pipeline investors and cause them to not favor the state as a partner in the project.

**14)** If the private sponsor groups welcomed the state as a partner, the state would receive some form of management participation based upon the level of its financial contribution. The state, however, would have a fiduciary responsibility to its partners to keep non-public data in confidence. The state may find itself, therefore, in an untenable legal and ethical position trying to balance the informational needs of the state government with its partnership responsibilities. In truth, since the gasline project will be subject to extensive regulation by various U.S. and Canadian governmental entities, much of the information pertinent to the partnership will be available through the regulatory process.

SECTION 11

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We would also like to recognize our consultants and thank them for their contributions. CH2M HILL's Dave Gray, Tom Rigert and Steve Reynolds prepared the analysis of the pipeline investment setting, regulatory constraints, risks and returns, and projected effect on the state's cash flow. They also created a financial model to simulate the state's investment and risk profiles. Bill Garner of Petrie Parkman & Company prepared the analysis of financing and ownership options, feasibility and the potential effects of state participation on the state's creditworthiness and potential project success.

# Appendix A
# SB 158

# HOUSE CS FOR CS FOR SENATE BILL NO. 158(FIN)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SECOND LEGISLATURE - FIRST SESSION

**BY THE HOUSE FINANCE COMMITTEE**

**Offered: 5/4/01**
**Referred: Rules**

**Sponsor(s): SENATE RESOURCES COMMITTEE**

## A BILL

## FOR AN ACT ENTITLED

**"An Act directing the commissioner of revenue to prepare a report to the legislature relating to the state's participation in owning or financing a gas pipeline project; and providing for an effective date."**

**BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

*** Section 1.** The uncodified law of the State of Alaska is amended by adding a new section to read:

REPORT OF THE COMMISSIONER OF REVENUE. (a) In furtherance of the public policy that the State of Alaska "encourage . . . the development of its resources by making them available for maximum use consistent with the public interest," and the obligation of the legislature to "provide for the utilization, development, and conservation of all natural resources belonging to the State . . . for the maximum benefit of its people," the commissioner of revenue shall, not later than January 31, 2002, provide to the governor and legislature a comprehensive report, with recommendations, addressing options for the state to participate in the commercial development of the state's natural gas resources through ownership of or provision of financing for a gas pipeline project. The report must consider whether

(1) the state should participate by taking an equity position in a gas pipeline project by

(A) owning all or a portion of the project; or

(B) establishing a state-owned public corporation or authority to construct and operate the project;

(2) the state should participate in financing the project and, if so,

(A) whether it should

(i) issue debt, in the form of its general obligation bonds or revenue bonds of a state-owned public corporation or authority or in another appropriate form; or

(ii) guarantee debt; and

(B) what terms it, or its public corporation or authority, should require as conditions for provision of financial support for the project;

(3) the state is able to participate under (1) or (2) of this subsection; the consideration given under this subsection must examine the effect of that participation on the state's cash flow, its continuing ability to pay for essential public services, and the effect of its participation on the state's financial integrity and creditworthiness;

(4) state participation under (1) or (2) of this subsection would

(A) create additional risks for the completion and operation of the project;

(B) more likely than not cause the project to be completed and to operate successfully; and

(C) accrue benefits or detriments for other parties participating with the state or its public corporation or authority in the completion and operation of the project; and

(5) the state should participate in a gas pipeline project by establishing a private corporation, which would be composed of Alaska residents who wish to become shareholders, that would own a portion of the project or assist in the construction and operation of the project.

(b) The commissioner of revenue shall

(1) contract with a qualified and suitable firm or person qualified by education or experience or of demonstrated competence for the performance of the requirements described in (a) of this section; the contract awarded under this paragraph is made for a purpose in which timely performance is essential that makes a procurement under AS 36.30 through competitive sealed bidding or competitive sealed proposals impracticable;

(2) require, as a term of the contract, that the person or one or more representatives of the firm with which the commissioner contracts under (1) of this subsection meet with the legislators who, during the Twenty-Second Alaska State Legislature, constitute the membership of the Joint Committee on Natural Gas Pipelines, for the purposes of allowing review of the data and providing information to those legislators or designees regarding the preparation and content of the report to be prepared under (a) of this section;

(3) provide progress reports regarding the preparation of the report to the chairs of the committees described in (2) of this subsection at intervals of no more than 60 days; and

(4) prepare and deliver a comprehensive report with final recommendations.

* **Sec. 2.** The uncodified law of the State of Alaska is amended by adding a new section to read:

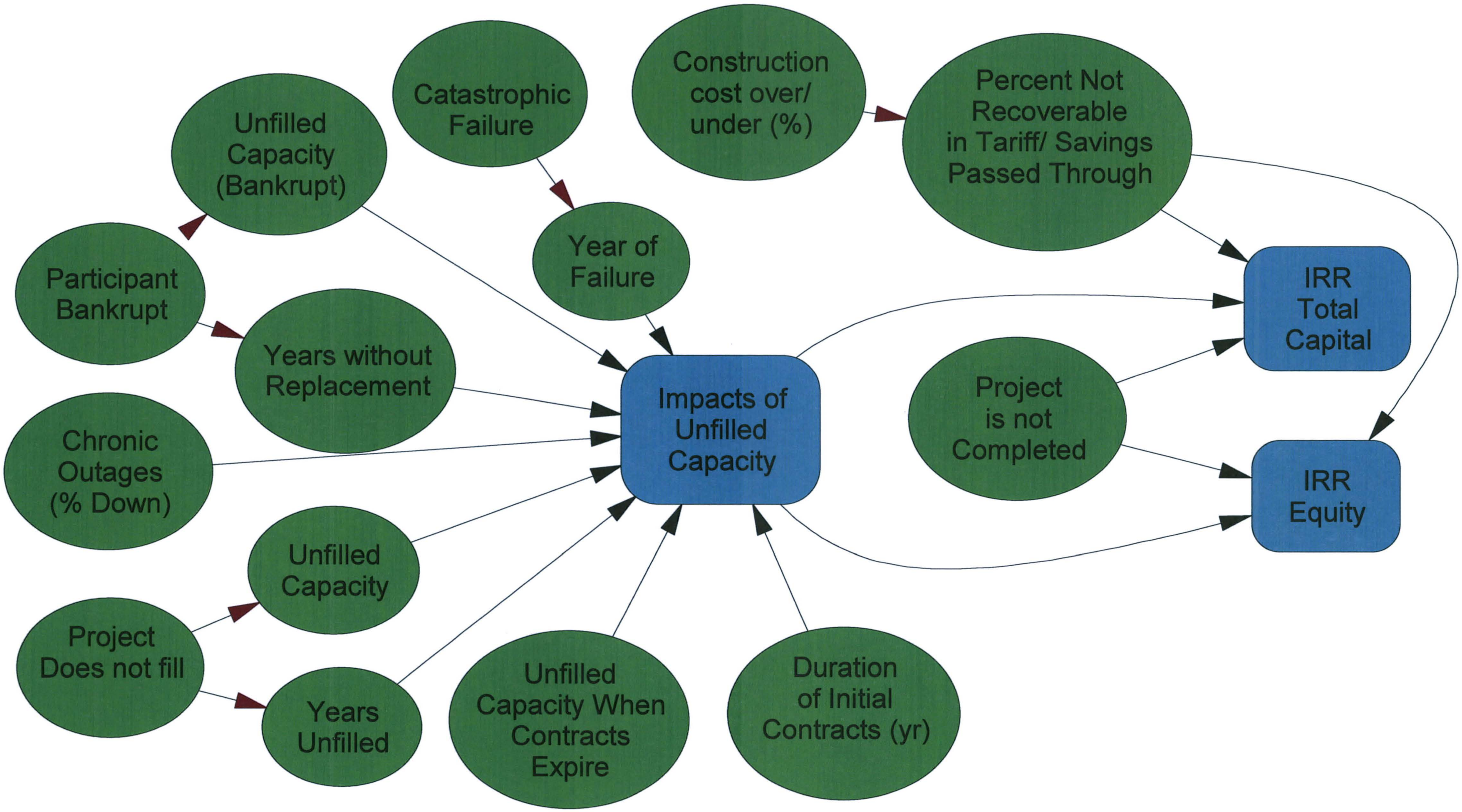
CONDITIONAL EFFECT. This Act takes effect only if the Twenty-Second Alaska State Legislature adopts a final version of Senate Concurrent Resolution 14, establishing the Joint Committee on Natural Gas Pipelines as a joint interim committee of the Alaska State Legislature.

* **Sec. 3.** If under sec. 2 of this Act this Act takes effect, it takes effect immediately under AS 01.10.070(c).

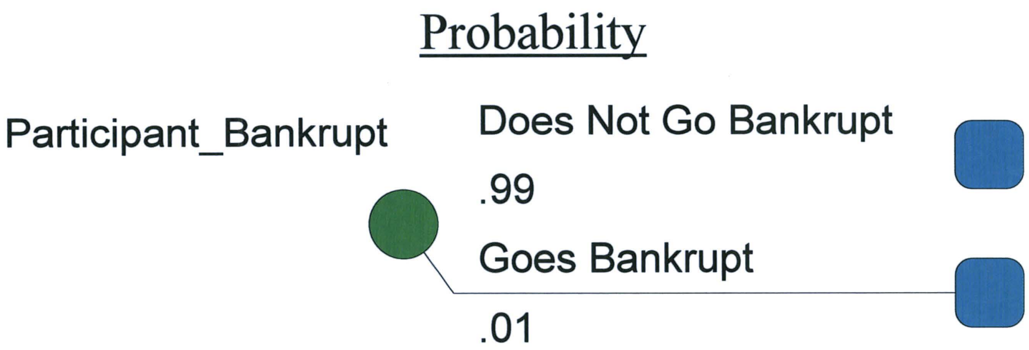
# Appendix B
# Risk Analysis Structure

# Cost Drivers and Uncertainties Effecting Returns on the Alaska Gas Pipeline

***Influence Diagrams illustrate conditional relationships between decisions, uncertainties, & outcomes***

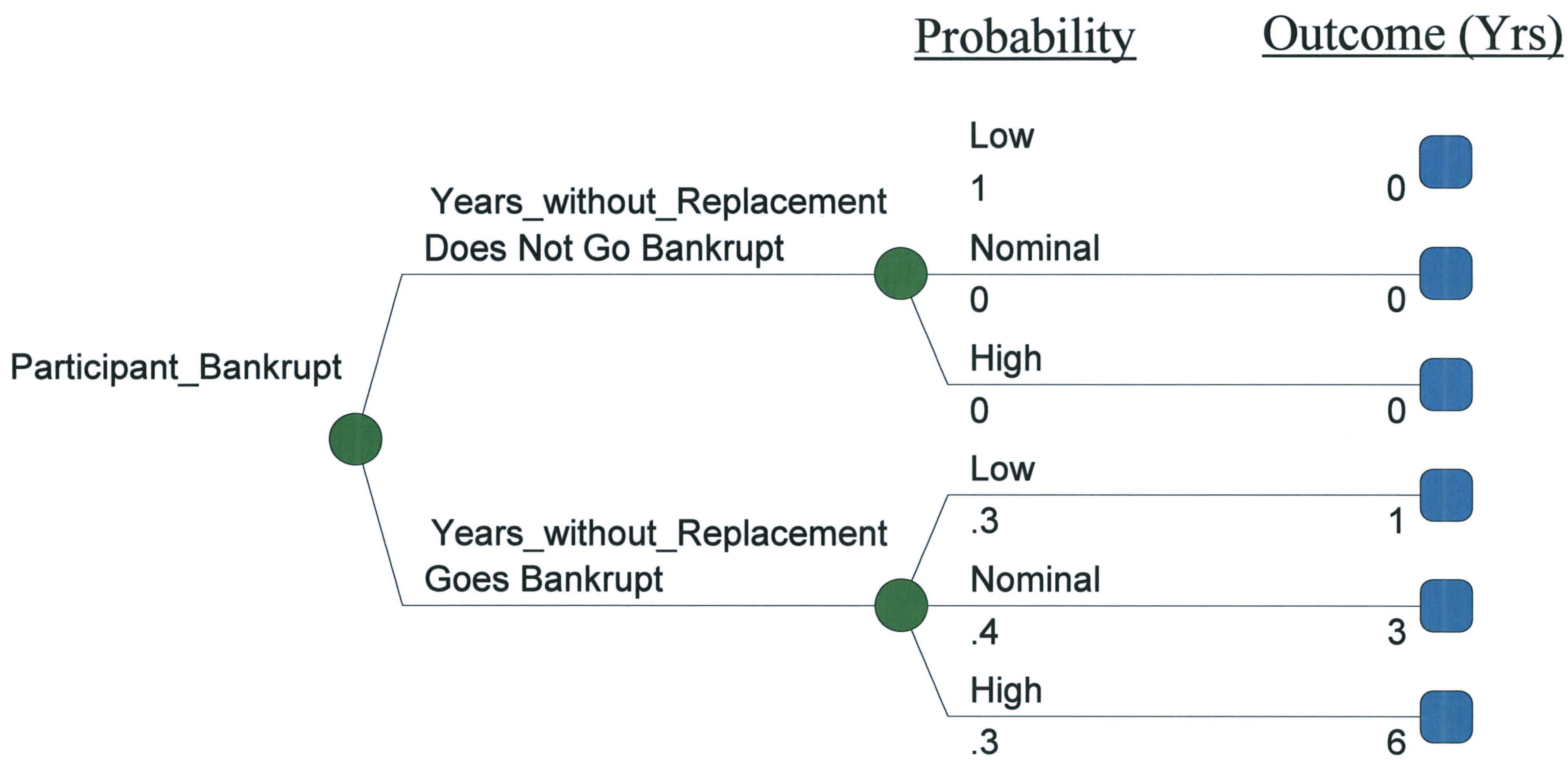


# Uncertainty Branch



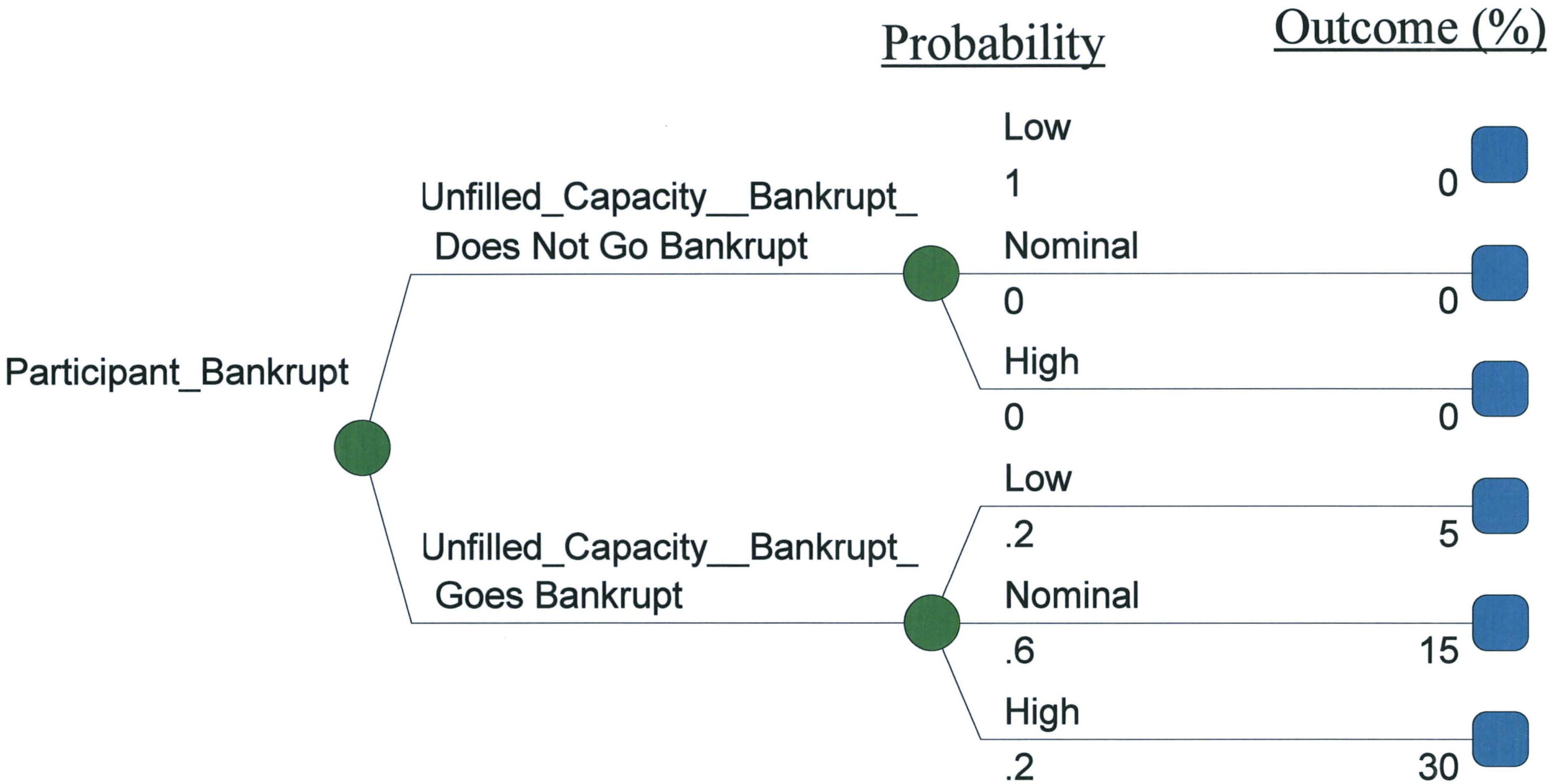

*Note:* Numbers on left represent branch probability.

# Uncertainty Branch



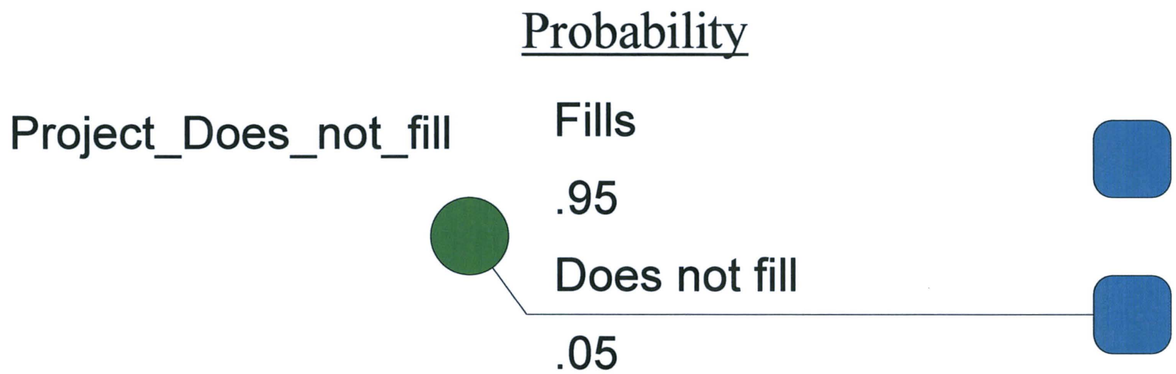

*Note:* Numbers on left represent branch probability.
Numbers on right represent value (years, $, %, etc…)

# Uncertainty Branch



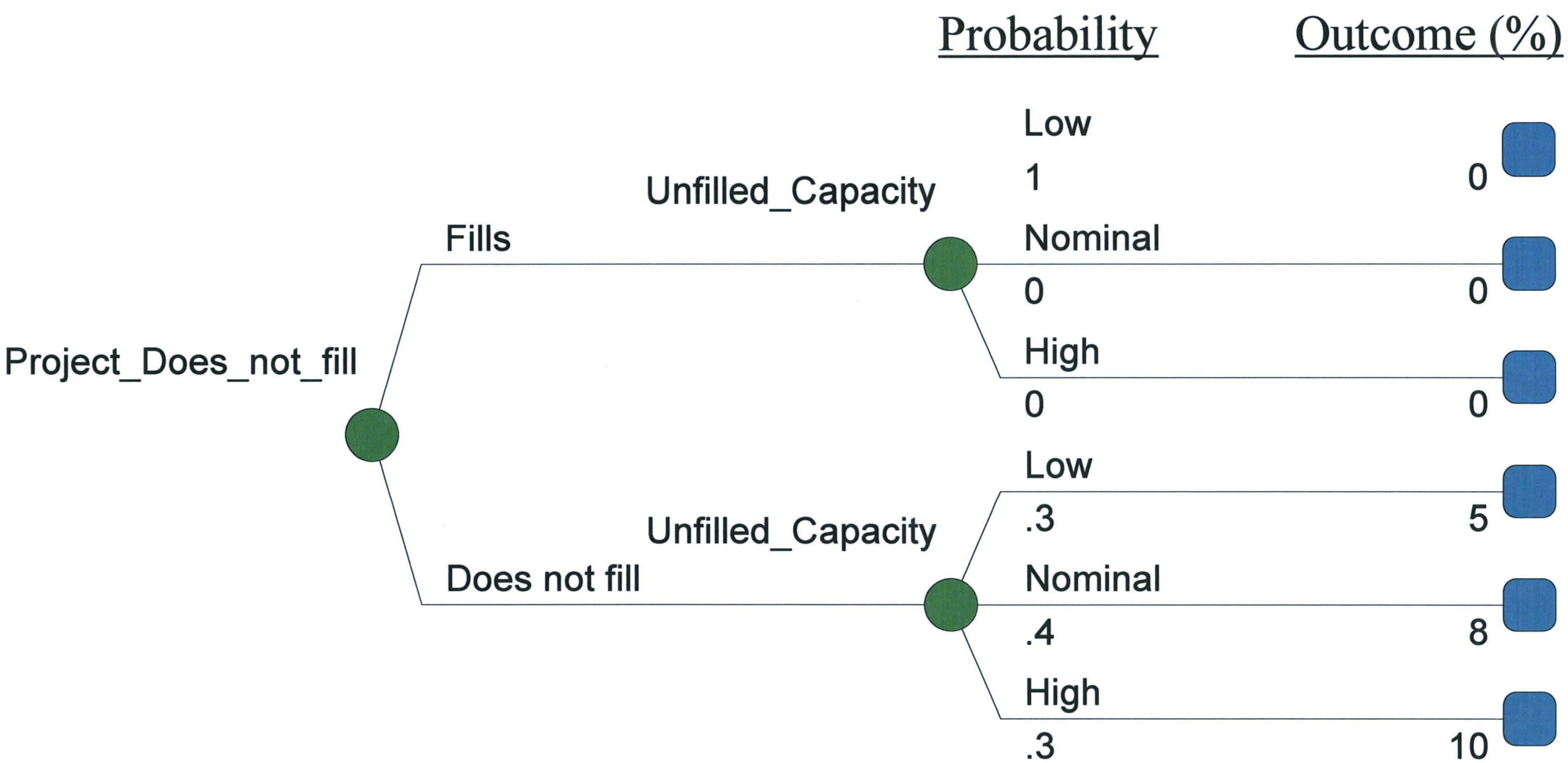

*Note:* Numbers on left represent branch probability.
Numbers on right represent value (years, $, %, etc…)

# Uncertainty Branch



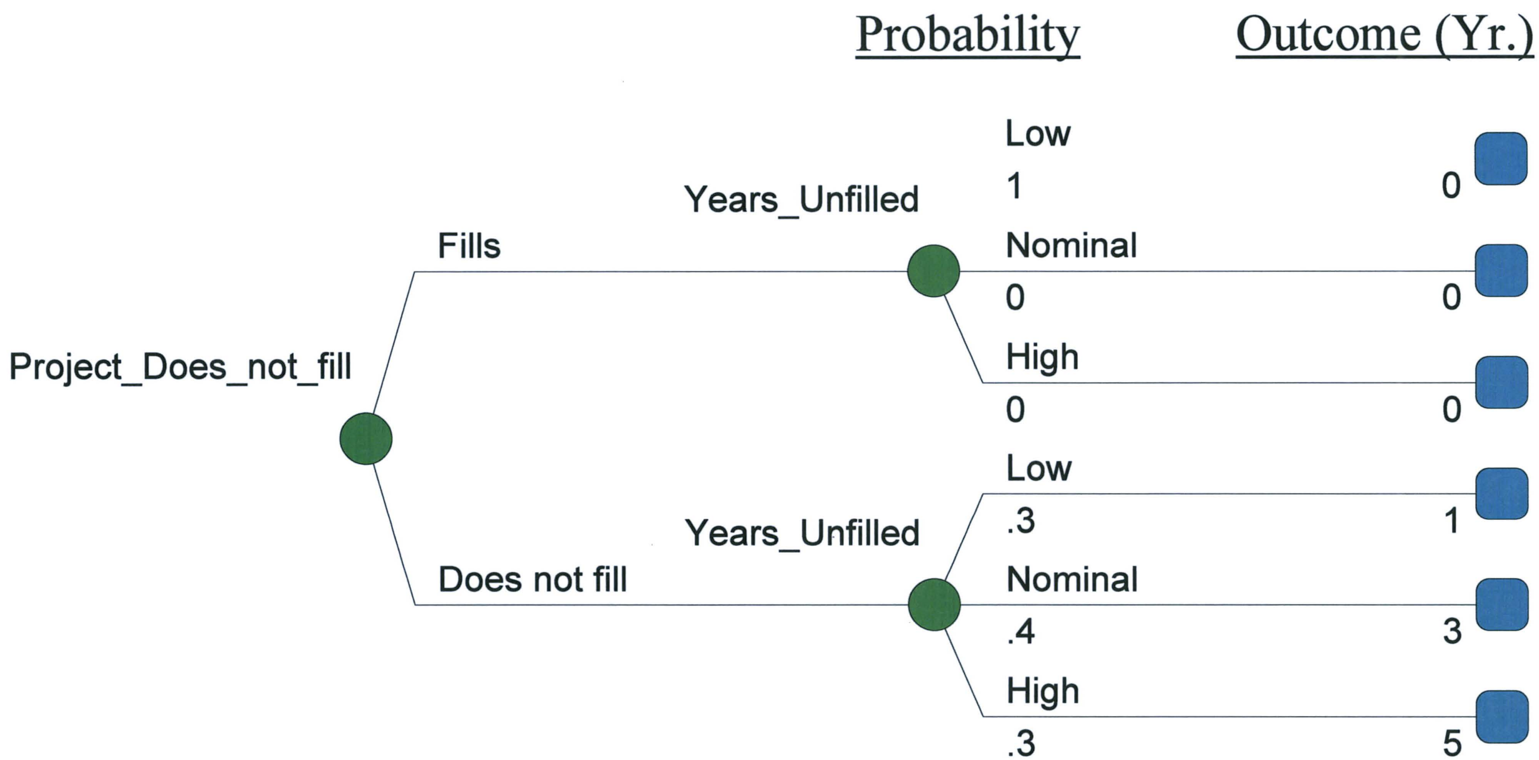

*Note:* Numbers on left represent branch probability.

# Uncertainty Branch



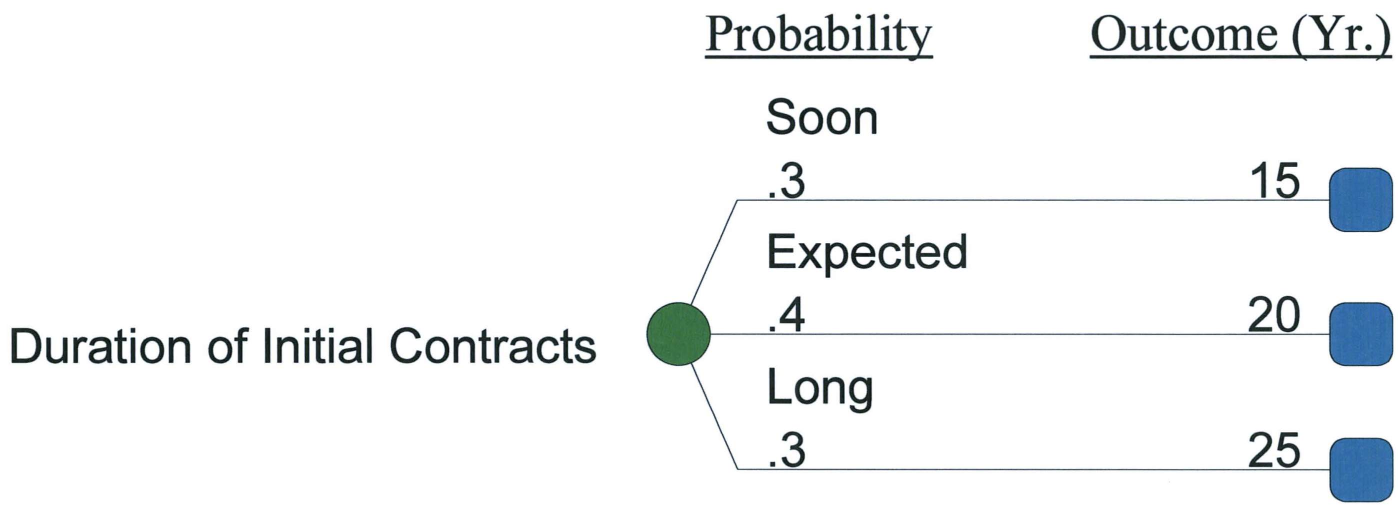

*Note:* Numbers on left represent branch probability.
Numbers on right represent value (years, $, %, etc…)

# Uncertainty Branch



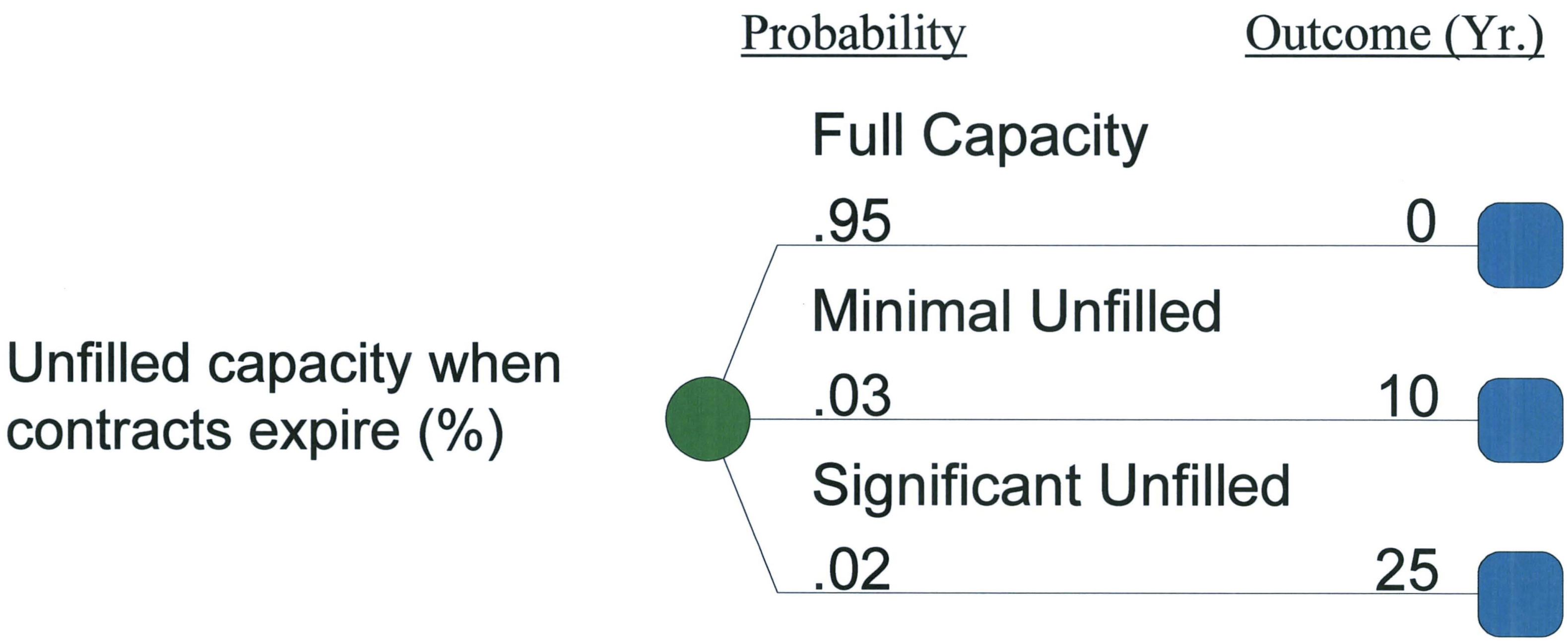

*Note:* Numbers on left represent branch probability.
Numbers on right represent value (years, $, %, etc…)

# Uncertainty Branch



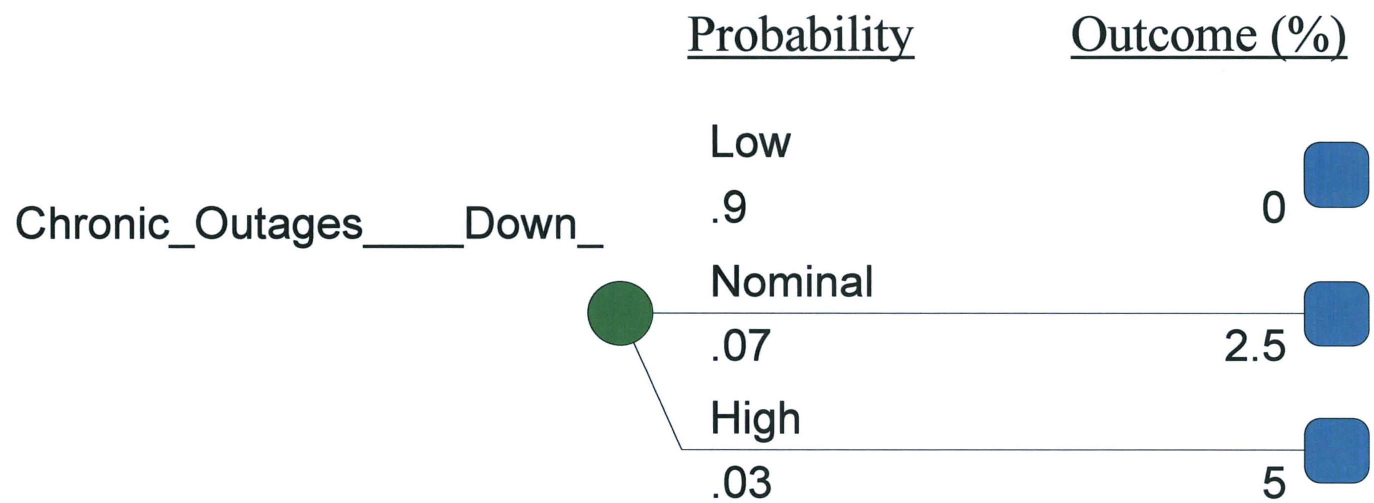

*Note:* Numbers on left represent branch probability.
Numbers on right represent value (years, $, %, etc…)

# Uncertainty Branch



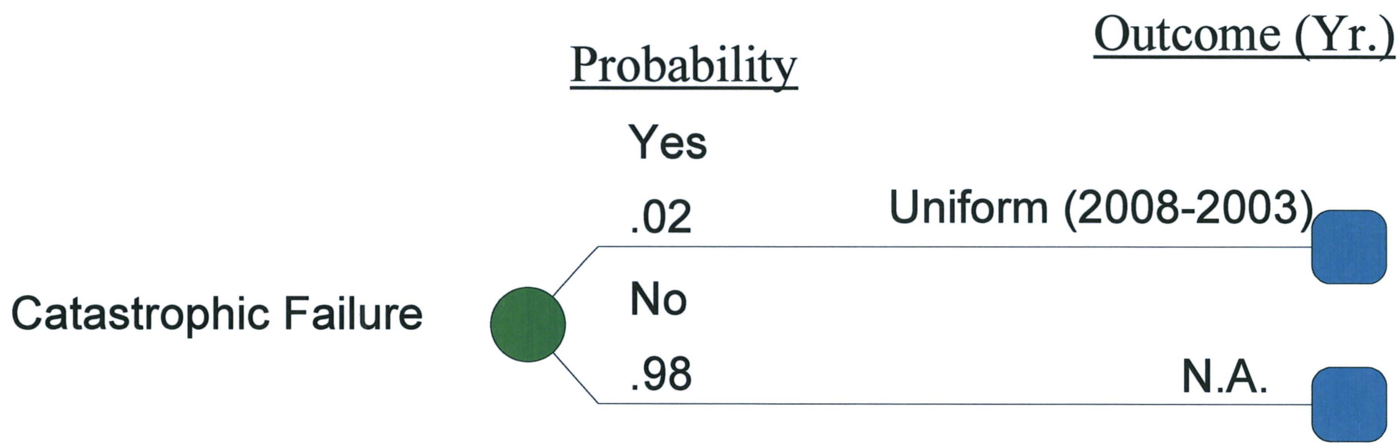

*Note:* Numbers on left represent branch probability.
Numbers on right represent value (years, $, %, etc…)

# Uncertainty Branch



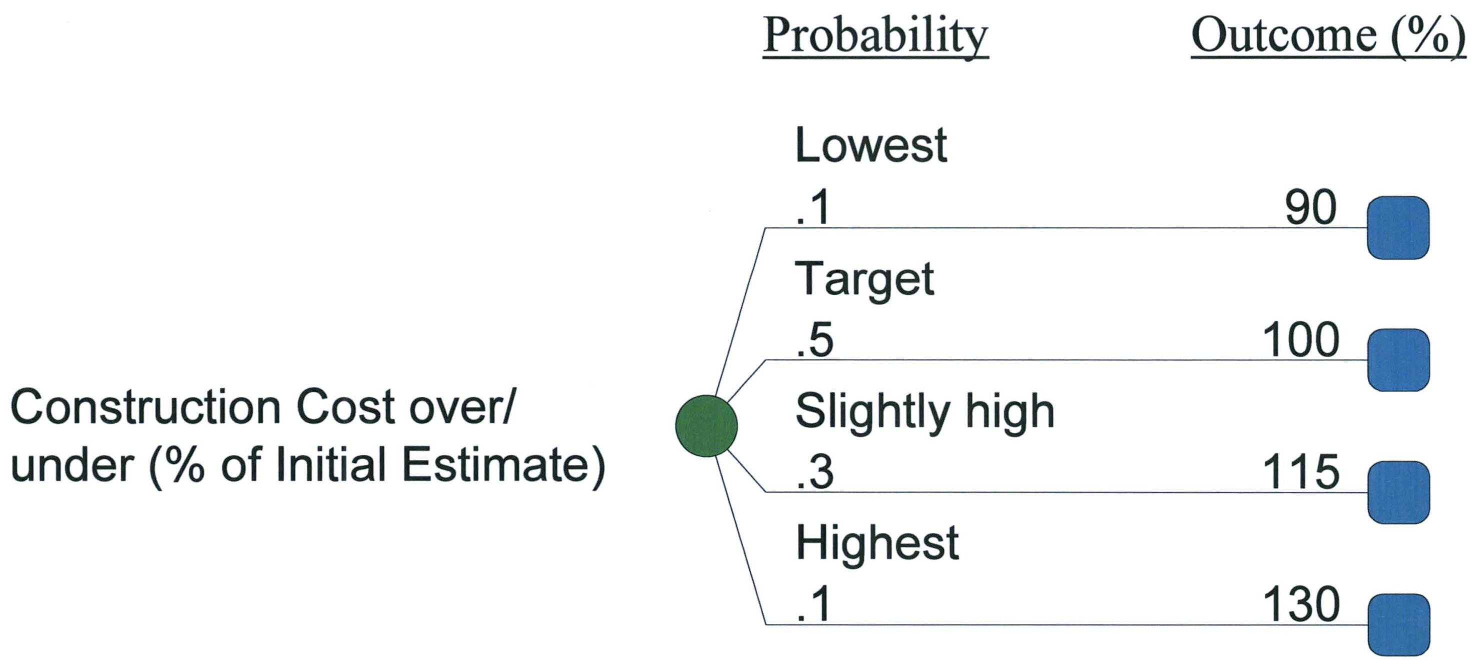

*Note:* Numbers on left represent branch probability.
Numbers on right represent value (years, $, %, etc…)

# Uncertainty Branch



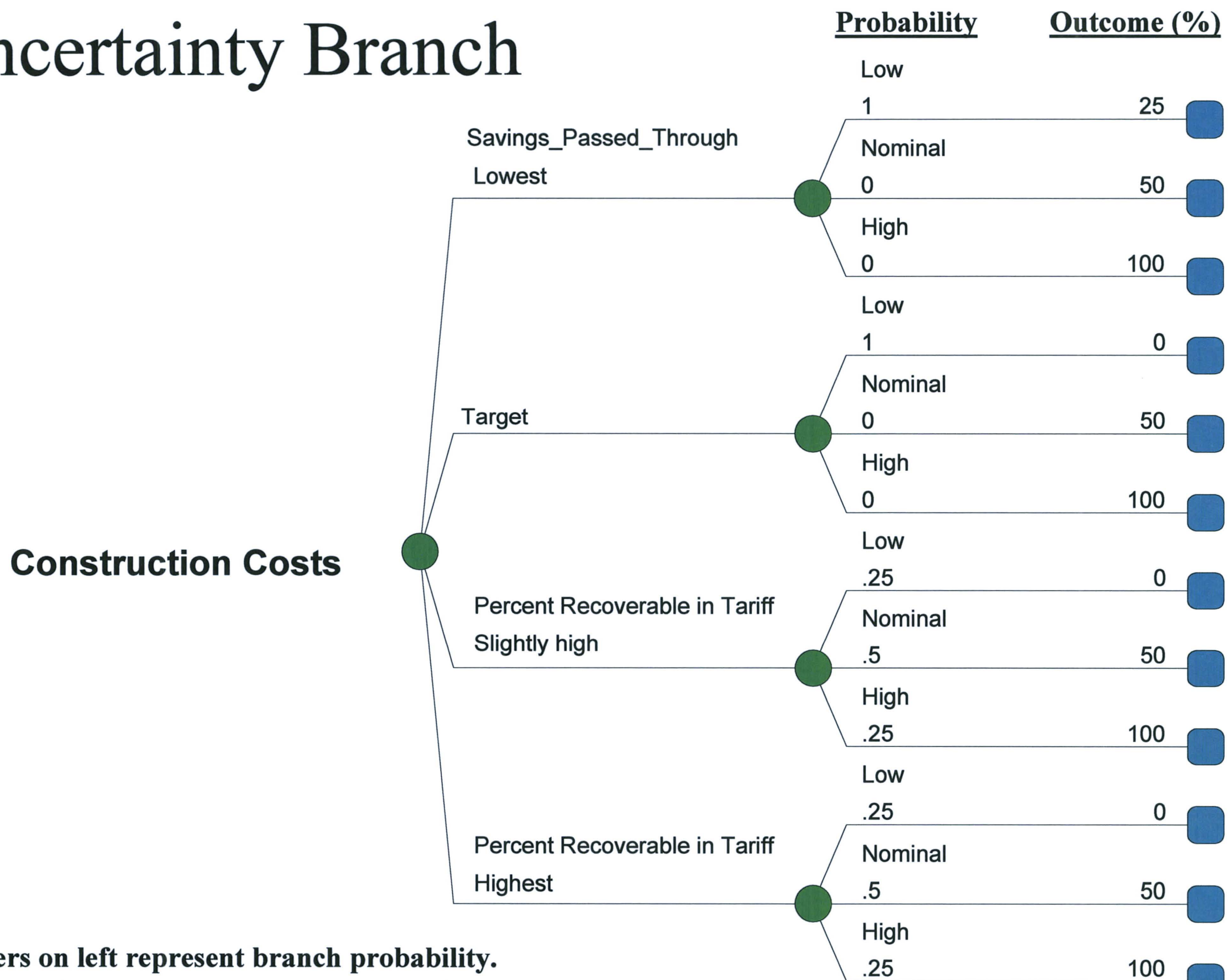

*Note:* Numbers on left represent branch probability.
Numbers on right represent value (years, $, %, etc…)

# Uncertainty Branch



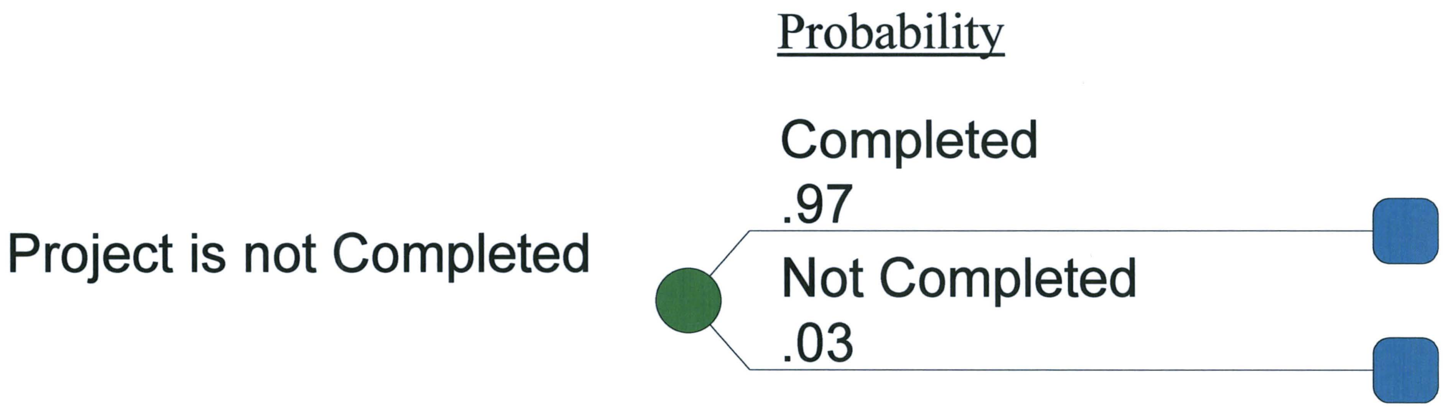

*Note:* Numbers on left represent branch probability.
Numbers on right represent value (years, $, %, etc…)

# Uncertainty Branch




*Note:* **Numbers on left represent branch probability.**
**Numbers on right represent value (years, \$, %, etc...)**

# Uncertainty Branch




*Note:* Numbers on left represent branch probability.

# Appendix C
# Sample Model Input and Output

**TABLE 1**

Alaska Gas Pipeline

Financial Analysis of Ownership Participation by the State of Alaska

General Inputs

(All dollar amounts in 2001 prices)

| | | |
|---|---|---|
| Initial Year of Operation | 2009 | |
| Alaska Ownership Share | 12.5% | |
| Total Capital Cost of Pipeline, North Slope to Alberta | 9.00 | Billion Dollars |
| Life of Project | 25 | years |
| Tax Depreciation Life | 15 | years |
| Tax Depreciation Acceration Rate | 1.5 | times declining balance |
| Operation and Maintenance | 2.2% | of Capital Cost |
| Property Tax | 2.0% | of Assessed Valuation |
| Market Price (delivered to Lower 48) | $3.00 | per Million Btu |
| Energy Content | 1080 | Btu per cubic foot |
| System Capacity | 4.0 | Bcf/d |
| Annual Load Factor | 95% | |
| Toll from Alberta to Lower 48 | $0.72 | per MMBtu |
| Percent Debt | 70% | |
| Debt Term | 20 | years |
| Cost of Debt | 7.50% | per year |
| Cost of Equity | 12.00% | per year |
| Weighed Cost of Capital | 8.85% | per year |
| Real cost of capital | 6.20% | per year |
| Inflation | 2.5% | per year |
| Percent Subject to US Taxes | 50.0% | |
| US Income Tax Rates | | |
| State of Alaska | 9.40% | |
| Federal | 35% | |
| Canadian Income Tax Rates | | |
| Federal | 22.12% | |
| Provincial (Estimated Weighted Average) | 14.00% | |
| Total | 36.12% | |

TABLE 2

Alaska Gas Pipeline

Financial Analysis of Ownership Participation by the State of Alaska

Investment Costs

(Billions of Dollars)

01/25/02

| Year | Cumulative Through 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | Total |
|---|---|---|---|---|---|---|---|---|---|
| Planning and Construction | | | | | | | | | |
| Expenditure profile | 2% | 2% | 10% | 16% | 22% | 23% | 18% | 7% | 100% |
| Billions of 2001 Dollars | 0.21 | 0.22 | 0.91 | 1.40 | 1.98 | 2.06 | 1.61 | 0.62 | 9.00 |
| Billions of Nominal $ | 0.21 | 0.23 | 0.96 | 1.51 | 2.18 | 2.33 | 1.87 | 0.73 | 10.01 |
| AFUDC | 0.20 | 0.18 | 0.63 | 0.80 | 0.88 | 0.68 | 0.35 | 0.06 | 3.78 |
| Total Cost | 0.41 | 0.41 | 1.59 | 2.30 | 3.06 | 3.01 | 2.21 | 0.80 | 13.79 |
| | | | | | | | | | 13.79 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Allocation from Producers | 2% | 2% | 10% | 15% | 21% | 22% | 17% | 7% | 95% |
| Adjusted | 2.3% | 2.5% | 10.1% | 15.5% | 22.0% | 22.9% | 17.9% | 6.9% | 100.0% |

**TABLE 3**

Alaska Gas Pipeline

Financial Analysis of Ownership

Participation by the State of Alaska

Tariff and Base Internal Rate of Return Projections

Dollar Amounts in Millions unless Otherwise Indicated

| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Tariff Calculation (North Slope to Alberta)** | | | | | | | | | | | | | |
| Rate Base | | | | | | | | | | | | | |
| Beginning of Year | | 1,724 | 1,655 | 1,586 | 1,517 | 1,448 | 1,379 | 1,310 | 1,241 | 1,172 | 1,103 | 1,034 | 965 |
| less: Depreciation | | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 |
| End of Year | 1,724 | 1,655 | 1,586 | 1,517 | 1,448 | 1,379 | 1,310 | 1,241 | 1,172 | 1,103 | 1,034 | 965 | 896 |
| Property Tax Value | | | | | | | | | | | | | |
| Replacement Cost New Less Depreciation | | 1,724 | 1,696 | 1,666 | 1,633 | 1,598 | 1,560 | 1,519 | 1,475 | 1,428 | 1,378 | 1,324 | 1,266 |
| US Revenue Requirements | | | | | | | | | | | | | |
| Operation and Maintenance | | 15 | 15 | 16 | 16 | 17 | 17 | 17 | 18 | 18 | 19 | 19 | 20 |
| Depreciation | | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 |
| Property Tax | | 17 | 17 | 17 | 16 | 16 | 16 | 15 | 15 | 14 | 14 | 13 | 13 |
| US Income Taxes | | 16 | (12) | (7) | (3) | 1 | 4 | 5 | 4 | 3 | 2 | 2 | 1 |
| Interest Expense | | 45 | 43 | 42 | 40 | 38 | 36 | 34 | 33 | 31 | 29 | 27 | 25 |
| Return to Equity | | 31 | 30 | 29 | 27 | 26 | 25 | 24 | 22 | 21 | 20 | 19 | 17 |
| Total | | 159 | 128 | 130 | 131 | 132 | 132 | 130 | 126 | 122 | 118 | 114 | 110 |
| Canadian Revenue Requirements | | | | | | | | | | | | | |
| Operation and Maintenance | | 15 | 15 | 16 | 16 | 17 | 17 | 17 | 18 | 18 | 19 | 19 | 20 |
| Depreciation | | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 |
| Property Tax | | 17 | 17 | 17 | 16 | 16 | 16 | 15 | 15 | 14 | 14 | 13 | 13 |
| Canadian Income Taxes | | 25 | 13 | 13 | 13 | 14 | 14 | 14 | 15 | 15 | 15 | 15 | 15 |
| Interest Expense | | 45 | 43 | 42 | 40 | 38 | 36 | 34 | 33 | 31 | 29 | 27 | 25 |
| Return to Equity | | 31 | 30 | 29 | 27 | 26 | 25 | 24 | 22 | 21 | 20 | 19 | 17 |
| Total | | 168 | 153 | 150 | 148 | 145 | 142 | 140 | 137 | 134 | 131 | 128 | 125 |
| Total Revenue Requirements | | | | | | | | | | | | | |
| Operation and Maintenance | | 30 | 31 | 32 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 |
| Depreciation | | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 |
| Property Tax | | 34 | 34 | 33 | 33 | 32 | 31 | 30 | 30 | 29 | 28 | 26 | 25 |
| Income Taxes | | 40 | 0 | 6 | 10 | 14 | 18 | 19 | 19 | 18 | 17 | 17 | 16 |
| Interest Expense | | 90 | 87 | 83 | 80 | 76 | 72 | 69 | 65 | 62 | 58 | 54 | 51 |
| Return to Equity | | 62 | 60 | 57 | 55 | 52 | 50 | 47 | 45 | 42 | 40 | 37 | 35 |
| Total Revenue Requirements | | 327 | 280 | 280 | 279 | 277 | 274 | 270 | 263 | 256 | 249 | 242 | 235 |

TABLE 3

Alaska Gas Pipeline

Financial Analysis of Ownership

Participation by the State of Alaska

Tariff and Base Internal Rate of Return Projections

Dollar Amounts in Millions unless Otherwise Indicated

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Tariff Calculation (North Slope to Alberta)** | | | | | | | | | | | | | |
| Rate Base | | | | | | | | | | | | | |
| Beginning of Year | 896 | 827 | 758 | 689 | 620 | 552 | 483 | 414 | 345 | 276 | 207 | 138 | 69 |
| less: Depreciation | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 |
| End of Year | 827 | 758 | 689 | 620 | 552 | 483 | 414 | 345 | 276 | 207 | 138 | 69 | (0) |
| Property Tax Value | | | | | | | | | | | | | |
| Replacement Cost New Less Depreciation | 1,205 | 1,140 | 1,072 | 998 | 921 | 839 | 753 | 661 | 565 | 463 | 356 | 243 | 125 |
| US Revenue Requirements | | | | | | | | | | | | | |
| Operation and Maintenance | 20 | 21 | 21 | 22 | 22 | 23 | 24 | 24 | 25 | 25 | 26 | 27 | 27 |
| Depreciation | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 |
| Property Tax | 12 | 11 | 11 | 10 | 9 | 8 | 8 | 7 | 6 | 5 | 4 | 2 | 1 |
| US Income Taxes | (0) | (1) | (2) | 15 | 32 | 31 | 30 | 29 | 28 | 28 | 27 | 26 | 25 |
| Interest Expense | 24 | 22 | 20 | 18 | 16 | 14 | 13 | 11 | 9 | 7 | 5 | 4 | 2 |
| Return to Equity | 16 | 15 | 14 | 12 | 11 | 10 | 9 | 7 | 6 | 5 | 4 | 2 | 1 |
| Total | 106 | 102 | 98 | 112 | 125 | 121 | 117 | 113 | 108 | 104 | 100 | 95 | 91 |
| Canadian Revenue Requirements | | | | | | | | | | | | | |
| Operation and Maintenance | 20 | 21 | 21 | 22 | 22 | 23 | 24 | 24 | 25 | 25 | 26 | 27 | 27 |
| Depreciation | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 | 34 |
| Property Tax | 12 | 11 | 11 | 10 | 9 | 8 | 8 | 7 | 6 | 5 | 4 | 2 | 1 |
| Canadian Income Taxes | 15 | 15 | 15 | 15 | 15 | 15 | 14 | 14 | 14 | 14 | 14 | 13 | 13 |
| Interest Expense | 24 | 22 | 20 | 18 | 16 | 14 | 13 | 11 | 9 | 7 | 5 | 4 | 2 |
| Return to Equity | 16 | 15 | 14 | 12 | 11 | 10 | 9 | 7 | 6 | 5 | 4 | 2 | 1 |
| Total | 122 | 118 | 115 | 112 | 108 | 105 | 101 | 98 | 94 | 90 | 87 | 83 | 79 |
| Total Revenue Requirements | | | | | | | | | | | | | |
| Operation and Maintenance | 41 | 42 | 43 | 44 | 45 | 46 | 47 | 48 | 49 | 51 | 52 | 53 | 55 |
| Depreciation | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 |
| Property Tax | 24 | 23 | 21 | 20 | 18 | 17 | 15 | 13 | 11 | 9 | 7 | 5 | 2 |
| Income Taxes | 15 | 14 | 13 | 30 | 47 | 46 | 45 | 44 | 42 | 41 | 40 | 39 | 38 |
| Interest Expense | 47 | 43 | 40 | 36 | 33 | 29 | 25 | 22 | 18 | 14 | 11 | 7 | 4 |
| Return to Equity | 32 | 30 | 27 | 25 | 22 | 20 | 17 | 15 | 12 | 10 | 7 | 5 | 2 |
| Total Revenue Requirements | 228 | 221 | 213 | 224 | 234 | 226 | 218 | 211 | 203 | 195 | 186 | 178 | 170 |

**TABLE 3**

Alaska Gas Pipeline
Financial Analysis of Ownership
Participation by the State of Alaska

Tariff and Base Internal Rate of Return Projections
Dollar Amounts in Millions unless Otherwise Indicated

| | | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Revenue Requirement per MMBtu | | | | | | | | | | | | | | |
| US | | | 0.85 | 0.68 | 0.69 | 0.70 | 0.70 | 0.71 | 0.70 | 0.67 | 0.65 | 0.63 | 0.61 | 0.59 |
| Canadian | | | 0.90 | 0.82 | 0.80 | 0.79 | 0.77 | 0.76 | 0.75 | 0.73 | 0.71 | 0.70 | 0.68 | 0.67 |
| Total | | | 1.74 | 1.50 | 1.49 | 1.49 | 1.48 | 1.47 | 1.44 | 1.40 | 1.37 | 1.33 | 1.29 | 1.26 |
| Levelized Tariff Estimates | | | | | | | | | | | | | | |
| Nominal Tariffs (Current $/MMBtu) | | | | | | | | | | | | | | |
| Total Tariff | 1.38 | | | | | | | | | | | | | |
| Included Income Taxes | 0.11 | | | | | | | | | | | | | |
| Tariff w/o Inc Taxes | 1.27 | | | | | | | | | | | | | |
| Added Cost of Inc Taxes | | | | | | | | | | | | | | |
| Total | 8.7% | | | | | | | | | | | | | |
| Federal only | 6.7% | | | | | | | | | | | | | |
| Monthly Cost | 21.23 | | | | | | | | | | | | | |
| Levelized Tariff (Constant 2001$) | | | | | | | | | | | | | | |
| Total Tariff | | | 1.43 | 1.20 | 1.17 | 1.13 | 1.10 | 1.06 | 1.02 | 0.97 | 0.92 | 0.87 | 0.83 | 0.79 |
| Levelized | 0.92 | | | | | | | | | | | | | |
| **Projected Income, Cash Flow, and Internal Rate of Return** | | | | | | | | | | | | | | |
| Income Statement | | | | | | | | | | | | | | |
| Revenues | | | | | | | | | | | | | | |
| Tariff[1] ($/MMBtu) | | | 1.74 | 1.50 | 1.49 | 1.49 | 1.48 | 1.47 | 1.44 | 1.40 | 1.37 | 1.33 | 1.29 | 1.26 |
| Annual Sales (BCF) | | | 173 | 173 | 173 | 173 | 173 | 173 | 173 | 173 | 173 | 173 | 173 | 173 |
| Btu per cubic foot | | | 1,080 | 1,080 | 1,080 | 1,080 | 1,080 | 1,080 | 1,080 | 1,080 | 1,080 | 1,080 | 1,080 | 1,080 |
| Total Revenues | | | 327 | 280 | 280 | 279 | 277 | 274 | 270 | 263 | 256 | 249 | 242 | 235 |
| Operating Expenses | | | | | | | | | | | | | | |
| Operation and Maintenance | | | 30 | 31 | 32 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 |
| Depreciation | | | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 |
| Property Tax | | | 34 | 34 | 33 | 33 | 32 | 31 | 30 | 30 | 29 | 28 | 26 | 25 |
| Total Operating Expenses | | | 134 | 134 | 134 | 134 | 134 | 134 | 134 | 134 | 134 | 134 | 134 | 134 |
| Operating Income before Income Tax | | | 193 | 147 | 146 | 145 | 143 | 140 | 135 | 129 | 122 | 115 | 108 | 101 |
| US Income Taxes | | | 15.64 | (12.30) | (7.45) | (3.20) | 0.57 | 3.91 | 5.03 | 4.16 | 3.24 | 2.43 | 1.50 | 0.70 |
| Canadian Income Taxes | | | 24.85 | 12.58 | 13.06 | 13.49 | 13.86 | 14.18 | 14.44 | 14.66 | 14.83 | 14.96 | 15.04 | 15.09 |
| Operating Income after Income Taxes | | | 153 | 146 | 140 | 134 | 128 | 122 | 116 | 110 | 104 | 98 | 92 | 85 |
| Interest Expense | | | 90 | 87 | 83 | 80 | 76 | 72 | 69 | 65 | 62 | 58 | 54 | 51 |
| Net Income | | | 62 | 60 | 57 | 55 | 52 | 50 | 47 | 45 | 42 | 40 | 37 | 35 |

**TABLE 3**

Alaska Gas Pipeline

Financial Analysis of Ownership

Participation by the State of Alaska

Tariff and Base Internal Rate of Return Projections

Dollar Amounts in Millions unless Otherwise Indicated

| | | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Revenue Requirement per MMBtu | | | | | | | | | | | | | | |
| US | | 0.57 | 0.55 | 0.52 | 0.60 | 0.67 | 0.65 | 0.62 | 0.60 | 0.58 | 0.56 | 0.53 | 0.51 | 0.49 |
| Canadian | | 0.65 | 0.63 | 0.61 | 0.60 | 0.58 | 0.56 | 0.54 | 0.52 | 0.50 | 0.48 | 0.46 | 0.44 | 0.42 |
| Total | | 1.22 | 1.18 | 1.14 | 1.19 | 1.25 | 1.21 | 1.17 | 1.12 | 1.08 | 1.04 | 1.00 | 0.95 | 0.91 |
| Levelized Tariff Estimates | | | | | | | | | | | | | | |
| Nominal Tariffs (Current $/MMBtu) | | | | | | | | | | | | | | |
| Total Tariff | 1.38 | | | | | | | | | | | | | |
| Included Income Taxes | 0.11 | | | | | | | | | | | | | |
| Tariff w/o Inc Taxes | 1.27 | | | | | | | | | | | | | |
| Added Cost of Inc Taxes | | | | | | | | | | | | | | |
| Total | 8.7% | | | | | | | | | | | | | |
| Federal only | 6.7% | | | | | | | | | | | | | |
| Monthly Cost | 21.23 | | | | | | | | | | | | | |
| Levelized Tariff (Constant 2001$) | | | | | | | | | | | | | | |
| Total Tariff | | 0.74 | 0.70 | 0.66 | 0.68 | 0.69 | 0.65 | 0.61 | 0.58 | 0.54 | 0.51 | 0.47 | 0.44 | 0.41 |
| Levelized | 0.92 | | | | | | | | | | | | | |

**Projected Income, Cash Flow, and Internal Rate of Return**

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Income Statement | | | | | | | | | | | | | |
| Revenues | | | | | | | | | | | | | |
| Tariff[1] ($/MMBtu) | 1.22 | 1.18 | 1.14 | 1.19 | 1.25 | 1.21 | 1.17 | 1.12 | 1.08 | 1.04 | 1.00 | 0.95 | 0.91 |
| Annual Sales (BCF) | 173 | 173 | 173 | 173 | 173 | 173 | 173 | 173 | 173 | 173 | 173 | 173 | 173 |
| Btu per cubic foot | 1,080 | 1,080 | 1,080 | 1,080 | 1,080 | 1,080 | 1,080 | 1,080 | 1,080 | 1,080 | 1,080 | 1,080 | 1,080 |
| Total Revenues | 228 | 221 | 213 | 224 | 234 | 226 | 218 | 211 | 203 | 195 | 186 | 178 | 170 |
| Operating Expenses | | | | | | | | | | | | | |
| Operation and Maintenance | 41 | 42 | 43 | 44 | 45 | 46 | 47 | 48 | 49 | 51 | 52 | 53 | 55 |
| Depreciation | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 |
| Property Tax | 24 | 23 | 21 | 20 | 18 | 17 | 15 | 13 | 11 | 9 | 7 | 5 | 2 |
| Total Operating Expenses | 134 | 133 | 133 | 133 | 132 | 132 | 131 | 130 | 130 | 129 | 128 | 127 | 126 |
| Operating Income before Income Tax | 94 | 87 | 80 | 91 | 102 | 94 | 87 | 80 | 73 | 66 | 58 | 51 | 44 |
| US Income Taxes | (0.23) | (1.03) | (1.96) | 14.98 | 31.86 | 30.99 | 30.13 | 29.26 | 28.39 | 27.53 | 26.66 | 25.80 | 24.93 |
| Canadian Income Taxes | 15.10 | 15.07 | 15.02 | 14.92 | 14.80 | 14.65 | 14.47 | 14.27 | 14.04 | 13.78 | 13.51 | 13.21 | 12.89 |
| Operating Income after Income Taxes | 79 | 73 | 67 | 61 | 55 | 49 | 43 | 37 | 31 | 24 | 18 | 12 | 6 |
| Interest Expense | 47 | 43 | 40 | 36 | 33 | 29 | 25 | 22 | 18 | 14 | 11 | 7 | 4 |
| Net Income | 32 | 30 | 27 | 25 | 22 | 20 | 17 | 15 | 12 | 10 | 7 | 5 | 2 |

TABLE 3

Alaska Gas Pipeline

Financial Analysis of Ownership

Participation by the State of Alaska

Tariff and Base Internal Rate of Return Projections

Dollar Amounts in Millions unless Otherwise Indicated

| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| US Income Taxes | | | | | | | | | | | | | |
| Revenues | | 159 | 128 | 130 | 131 | 132 | 132 | 130 | 126 | 122 | 118 | 114 | 110 |
| Operation and Maintenance | | 15 | 15 | 16 | 16 | 17 | 17 | 17 | 18 | 18 | 19 | 19 | 20 |
| Depreciation (for Taxes) | | 43 | 82 | 74 | 66 | 60 | 54 | 51 | 51 | 51 | 51 | 51 | 51 |
| Property Tax | | 17 | 17 | 17 | 16 | 16 | 16 | 15 | 15 | 14 | 14 | 13 | 13 |
| Interest Expense | | 45 | 43 | 42 | 40 | 38 | 36 | 34 | 33 | 31 | 29 | 27 | 25 |
| Taxablle Income | | 38 | (30) | (18) | (8) | 1 | 10 | 12 | 10 | 8 | 6 | 4 | 2 |
| State of Alaska Tax | | 4 | (3) | (2) | (1) | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 0 |
| Federal Tax | | 12 | (9) | (6) | (2) | 0 | 3 | 4 | 3 | 2 | 2 | 1 | 1 |
| Total US Income Tax | | 16 | (12) | (7) | (3) | 1 | 4 | 5 | 4 | 3 | 2 | 2 | 1 |
| Canadian Income Taxes | | | | | | | | | | | | | |
| Revenues | | 168 | 153 | 150 | 148 | 145 | 142 | 140 | 137 | 134 | 131 | 128 | 125 |
| Operation and Maintenance | | 15 | 15 | 16 | 16 | 17 | 17 | 17 | 18 | 18 | 19 | 19 | 20 |
| Depreciation (for Taxes) | | 22 | 42 | 40 | 38 | 36 | 34 | 33 | 31 | 29 | 28 | 26 | 25 |
| Property Tax | | 17 | 17 | 17 | 16 | 16 | 16 | 15 | 15 | 14 | 14 | 13 | 13 |
| Interest Expense | | 45 | 43 | 42 | 40 | 38 | 36 | 34 | 33 | 31 | 29 | 27 | 25 |
| Taxablle Income | | 69 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 41 | 41 | 42 | 42 |
| Total Canadian Income Tax | | 25 | 13 | 13 | 13 | 14 | 14 | 14 | 15 | 15 | 15 | 15 | 15 |
| Cash Flow | | | | | | | | | | | | | |
| Capital Investment | (1,724) | | | | | | | | | | | | |
| Operating Income | | 153 | 146 | 140 | 134 | 128 | 122 | 116 | 110 | 104 | 98 | 92 | 85 |
| plus Depreciation | | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 |
| Net Cash Flow | (1,724) | 221 | 215 | 209 | 203 | 197 | 191 | 185 | 179 | 173 | 167 | 160 | 154 |
| Interest expense | | 90 | 87 | 83 | 80 | 76 | 72 | 69 | 65 | 62 | 58 | 54 | 51 |
| Principal payment | | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 |
| Principal and interest payment | (1,206) | 139 | 135 | 132 | 128 | 124 | 121 | 117 | 113 | 110 | 106 | 103 | 99 |
| Net Cash Flow after Interest Payment | (517) | 83 | 80 | 78 | 75 | 73 | 70 | 68 | 65 | 63 | 60 | 58 | 55 |
| IRR--Total Capital | 8.85% | | | | | | | | | | | | |
| IRR--Debt | 7.50% | | | | | | | | | | | | |
| IRR--Equity | 12.00% | | | | | | | | | | | | |

[1] The tariff shown is based on the simplifying assumption that the tariff will be equal to the annual revenue requirements. In fact the tariff will be negotiated to be fixed for many years base on a levelizing formul

ꞁaska

ꞁReturn Projections
ꞁs Otherwise Indicated

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 106 | 102 | 98 | 112 | 125 | 121 | 117 | 113 | 108 | 104 | 100 | 95 | 91 |
| aintenance | 20 | 21 | 21 | 22 | 22 | 23 | 24 | 24 | 25 | 25 | 26 | 27 | 27 |
| Taxes) | 51 | 51 | 51 | 25 | - | - | - | - | - | - | - | - | - |
| | 12 | 11 | 11 | 10 | 9 | 8 | 8 | 7 | 6 | 5 | 4 | 2 | 1 |
| | 24 | 22 | 20 | 18 | 16 | 14 | 13 | 11 | 9 | 7 | 5 | 4 | 2 |
| | (1) | (3) | (5) | 36 | 77 | 75 | 73 | 71 | 69 | 67 | 65 | 63 | 61 |
| ax | (0) | (0) | (0) | 3 | 7 | 7 | 7 | 7 | 6 | 6 | 6 | 6 | 6 |
| | (0) | (1) | (2) | 12 | 25 | 24 | 23 | 23 | 22 | 21 | 21 | 20 | 19 |
| e Tax | (0) | (1) | (2) | 15 | 32 | 31 | 30 | 29 | 28 | 28 | 27 | 26 | 25 |
| kes | | | | | | | | | | | | | |
| | 122 | 118 | 115 | 112 | 108 | 105 | 101 | 98 | 94 | 90 | 87 | 83 | 79 |
| aintenance | 20 | 21 | 21 | 22 | 22 | 23 | 24 | 24 | 25 | 25 | 26 | 27 | 27 |
| Taxes) | 24 | 23 | 22 | 20 | 19 | 18 | 18 | 17 | 16 | 15 | 14 | 14 | 13 |
| | 12 | 11 | 11 | 10 | 9 | 8 | 8 | 7 | 6 | 5 | 4 | 2 | 1 |
| | 24 | 22 | 20 | 18 | 16 | 14 | 13 | 11 | 9 | 7 | 5 | 4 | 2 |
| | 42 | 42 | 42 | 41 | 41 | 41 | 40 | 39 | 39 | 38 | 37 | 37 | 36 |
| Income Tax | 15 | 15 | 15 | 15 | 15 | 15 | 14 | 14 | 14 | 14 | 14 | 13 | 13 |
| | 79 | 73 | 67 | 61 | 55 | 49 | 43 | 37 | 31 | 24 | 18 | 12 | 6 |
| | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 |
| | 148 | 142 | 136 | 130 | 124 | 118 | 112 | 106 | 99 | 93 | 87 | 81 | 75 |
| | 47 | 43 | 40 | 36 | 33 | 29 | 25 | 22 | 18 | 14 | 11 | 7 | 4 |
| | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 | 48 |
| rest payment | 95 | 92 | 88 | 84 | 81 | 77 | 74 | 70 | 66 | 63 | 59 | 55 | 52 |
| nterest Payment | 53 | 50 | 48 | 46 | 43 | 41 | 38 | 36 | 33 | 31 | 28 | 26 | 23 |

ı the simplifying assumption that the tariff will be equal to the annual revenue requirements. In fact the tariff will be negotiated to be fixed for many years base on a levelizing fo

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