Preliminary Findings and Determination

As required by the

Stranded Gas Development Act

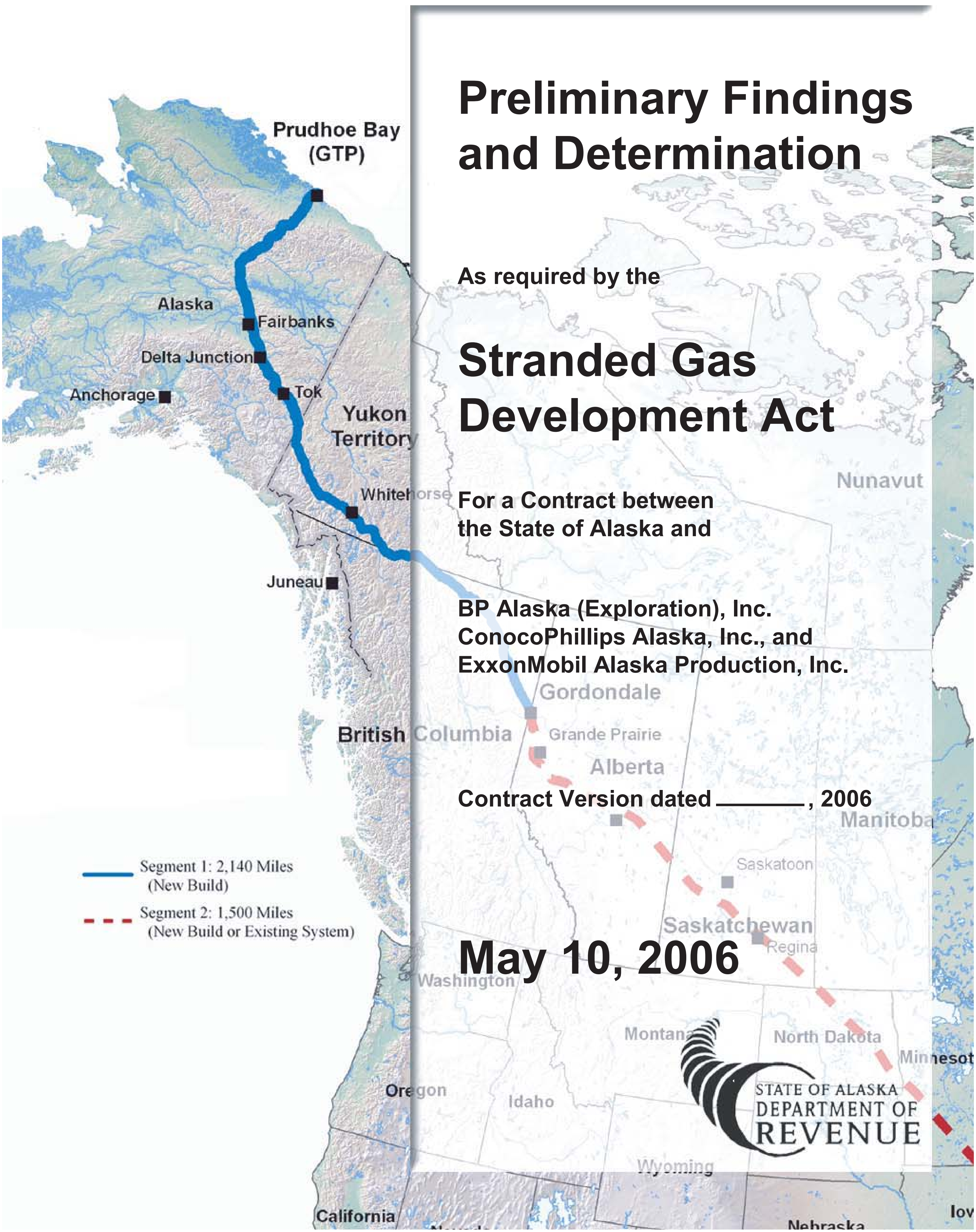
For a Contract between
the State of Alaska and

BP Alaska (Exploration), Inc.
ConocoPhillips Alaska, Inc., and
ExxonMobil Alaska Production, Inc.

Contract Version dated ________, 2006

May 10, 2006

STATE OF ALASKA
DEPARTMENT OF
REVENUE



STATE OF ALASKA

DEPARTMENT OF REVENUE

OFFICE OF THE COMMISSIONER

FRANK H. MURKOWSKI, GOVERNOR

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May 10, 2006

The Honorable Frank Murkowski, Governor
The Honorable Ben Stevens, President of the Alaska State Senate
The Honorable John Harris, Speaker of the Alaska House of Representatives
The Honorable Lyda Green, Co-Chair Senate Finance Committee
The Honorable Gary Wilken, Co-Chair Senate Finance Committee
The Honorable Mike Chenault, Co-Chair House Finance Committee
The Honorable Kevin Meyer, Co-Chair House Finance Committee
The Honorable Tom Wagoner, Chair Senate Resources Committee
The Honorable Jay Ramras, Co-Chair House Resources Committee
The Honorable Ralph Samuels, Co-Chair House Resources Committee
The Honorable Vic Kohring, Chair House Special Committee on Oil & Gas

Regarding: Transmittal of Preliminary Fiscal Interest Finding and the terms of the proposed Fiscal Contract between the State of Alaska and the Sponsor Group of the Alaska Gas Pipeline Project

Dear Governor and Legislators;

In accordance with the duties conferred on my office by AS 43.82.400, I am transmitting to you a copy of the Preliminary Fiscal Interest Finding and the proposed Alaska Stranded Gas Fiscal Contract between the State of Alaska and BP Exploration (Alaska) Incorporated, ConocoPhillips Alaska, Incorporated, and ExxonMobil, Alaska Production, Incorporated.

In compliance with the requirement of AS 43.82.410(2), the financial, technical, market data and other documents supporting the fiscal interest finding are open and available to the public through posting on the following website www.revenue.state.ak.us/Gasline/ContractDocuments

By separate action I have given the public notice required by AS 43.82.410(1).

Regards,

William A. Corbus

William A. Corbus
Commissioner

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STATE OF ALASKA
DEPARTMENT OF
REVENUE

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Abbreviations

ADNR	Alaska Department of Natural Resources
ADOR	Alaska Department of Revenue
ADOLWD	Alaska Department of Labor and Workforce Development
ADOTPF	Alaska Department of Transportation and Public Facilities
AECO	Alberta Energy Company
AECO/NIT	Alberta Energy Company/Nova Inventory Transfer
AEUB	Alberta Energy Utilities Board
AGPA	Alaska Gasline Port Authority
AGPC	Alaska Gas Pipeline Company
AJCA	American Jobs Creation Act
AJCN	Alaska Job Center Network
AlCan	Alaska Canada
ANGDA	Alaska Natural Gas Development Authority
ANGMC	Alaska Natural Gas Marketing Company
ANGPA	Alaska Natural Gas Pipeline Act
ANGPC	Alaska Natural Gas Pipeline Corporation
ANGTA	Alaska Natural Gas Transportation Act of 1976
ANGTS	Alaska Natural Gas Transportation System
ANNGTC	Alaskan Northwest Natural Gas Transportation Company
ANS	Alaska North Slope
ANWR	Arctic National Wildlife Refuge
APFC	Alaska Permanent Fund Corporation
APSC	Alyeska Pipeline Service Company
AVTEC	Alaska Vocational Technical Center
AWIB	Alaska Workforce Investment Board
BC	British Columbia
bcf/d	billion cubic feet per day
BP	BP Exploration (Alaska), Inc.
BLS	Bureau of Labor Statistics
BOE	barrel of oil equivalent
CFR	Code of Federal Regulations
CIRI	Cook Inlet Region, Inc.

CP	ConocoPhillips Alaska, Inc.
CPI	Consumer Price Index
CPR	Conflict Prevention and Resolution
DBP	Division of Business Partnerships
DOE	Department of Energy
DOI	Department of the Interior
DVR	Division of Vocational Rehabilitation
EIA	Energy Information Administration
EIS	Environmental Impact Statement
ELF	Economic Limit Factor
EM	ExxonMobil Alaska Production Inc.
ESD	Employment Security Division
EPC	Engineering, Procurement, and Construction
EUB	Energy Utilities Board (Alberta)
FEED	Front End Engineering and Design
FERC	Federal Energy Regulatory Commission
FNSB	Fairbanks North Star Borough
FPC	Federal Power Commission
FT	Firm Transportation
GAAP	Generally Accepted Accounting Procedures
GTL	Gas-to-Liquid
GTP	Gas Treatment Plant
IRR	Internal Rate of Return
JATC	Joint Apprenticeship and Training Committee
LLC	Limited Liability Corporation
LNG	Liquefied natural gas
LPG	Liquefied Petroleum Gas
MAGTC	MidAmerican Alaska Gas Transmission Company
Mbd	Million barrels per day
mcf	thousand cubic feet
MEHC	MidAmerican Energies Holding Company
mmBtu	million British Thermal Units
mmcf/d	million cubic feet per day
MOU	Memorandum of Understanding

NAFTA	North American Free Trade Agreement
NCF	Net Cash Flow, undiscounted
NEB	National Energy Board (of Canada)
NEBA	National Energy Board Act (of Canada)
NEPA	National Environmental Policy Act
NGL	Natural Gas Liquid
NGPA	Natural Gas Policy Act
NGTL	Nova Gas Transmission Ltd.
NSB	North Slope Borough
NPR-A	National Petroleum Reserve-Alaska
NPV	Net Present Value
NPV10	Net Present Value discounted at 10 percent
PBU	Prudhoe Bay Unit
PFR10	Profitability Ratio discounted at 10 percent
PILT	Payment in lieu of Taxes
POD	plan of development
PPT	Petroleum Profits Tax
PSE	Pacific Star Energy, LLC
PTU	Point Thomson Unit
PVM	Pedro van Meurs
RCA	Regulatory Commission
SCIT	State Corporate Income Tax
SG	Stranded Gas
SGDA	Stranded Gas Development Act
TAPS	Trans Alaska Pipeline System
tcf	trillion cubic feet
TOTE	Totem Ocean Trailer Express
UAA	University of Alaska Anchorage
UAF	University of Alaska Fairbanks
UCA	Upstream Cost Allowance
USGS	United States Geological Service
WCSB	Western Canadian Sedimentary Basin
WIA	Workforce Investment Act
WTI	West Texas Intermediate

List of Cited Legislation

Title of Act/Law	ID Number	Year
State		
Alaska Constitution	Art. IX, § 1	1959
Alaska Industrial Incentive Act		1957
Alaska Land Act - Sale of Royalty	AS 38.05.183	
Gas Production Tax	AS 43.55	
Municipal Powers and Duties – Powers	AS 29.35.620	
Oil and Gas Exploration, Production, and Pipeline Transportation Property Taxes	AS 43.56	
Pipeline Act	AS 42.06	
Public Land	AS 38.05.135	
Right of Way Leasing Act	AS 38.35.017	
State Corporate Income Tax (SCIT)	AS 43.20.072	
Stranded Gas Development Act (SGDA)	AS 43.82.010-43.82.990	1998
Stranded Gas Development Act—Amendment	House Bill 16	2003
Federal		
Agreement between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline	29 U.S.T. 3581	1977
American Jobs Creation Act (AJCA)	H.R.4520Public Law 108-357	2004
Alaska Natural Gas Pipeline Act (ANGPA)	15 U.S.C. 720	2004
Alaska Natural Gas Transportation Act of 1976 (ANGTA)	15 U.S.C. 719	1976
National Environmental Policy Act of 1969 (NEPA)	42 U.S.C. 4321	1970
Natural Gas Policy Act (NGPA)	15 U.S.C. 717	1978
Natural Gas Wellhead Decontrol Act	15 U.S.C. 3301	1989
FERC Regulations Governing the conduct of open seasons for Alaska Natural Gas Transportation Projects	18 C.F.R. § 157	2005
Trans-Alaska Pipeline Authorization Act	43 U.S.C.1651	1973
Transit Pipelines Treaty	28 U.S.T. 7449	1977
Waivers of Law	Pub. L. No. 97-93, 95 Stat. 1204	1981
Canadian		
Canadian Environmental Assessment Act	R.S. 1992, c. 37	1992
National Energy Board Act	R.S. 1985, c. N-7	1985
Northern Pipeline Act of 1978	R.S. 1985, c. N-26	1978

Glossary

Term	Definition
Alaska Project	the portion of the project located in Alaska
Alaska to Alberta Project	the portion of the project from the Alaska-Canada border to the Alberta Hub.
ANS	the Alaska North Slope, which is the portion of Alaska north of sixty-eight degrees (68°) North latitude.
Anchor Shipper	a shipper who has reached an agreement with the pipeline sponsor through one-on-one negotiation to support the project, by making a large early commitment to capacity on the proposed pipeline.
BOE	refers to barrel of oil equivalent. It is a method of equating oil, gas, and natural gas liquids. Gas is converted to oil based on its relative energy content at the rate of six mcf of gas to one barrel of oil. Natural gas liquids are converted based upon volume where one barrel of natural gas liquids equals one barrel of oil.
Capacity Allocation	the methodology by which pipeline capacity will be awarded.
Constant $	refers to a metric for valuing the price of something over time, without that metric changing due to inflation or deflation. The term specifically refers to dollars whose present value is linked to a given year.
End User	the ultimate consumer of a product, especially the one for whom the product has been designed.
Force Majuere	means a *force majeure* event that causes the inability to perform an obligation, materially adversely affects the performance of an obligation, or materially adversely affects the ability to satisfy the diligence standard under Article 5 of the Contract.
Hub	a major natural gas distribution point
Internal Rate of Return (IRR)	the discount rate that yields a net present value of zero for the net cash flows of a project.
Line Pack	a quantity of gas purchased for operational (non-commercial) use by the pipeline entity to fill and pressurize the pipeline prior to the commencement of commercial operations. The line pack quantity is considered a permanent part of the pipeline's asset base (and its cost is included in the tariff), allowing the pipeline to deliver gas for a shipper at a pipeline delivery point at the same time the shipper delivers that quantity of gas to a pipeline receipt point.

Mainline	the large diameter pipeline that is routed generally along the TAPS pipeline and the Alaska Canada Highway, compressor stations and related facilities, including any additions, improvements, expansions, extensions or renewals or replacements to the pipeline, compressor stations or related facilities, designed to transport gas from the ANS to off-take points and to connect with the non-Alaska project.
Mainline Entity	the project entity formed to own the mainline.
Midstream Element	means a gas transmission pipeline, a gas treatment plant, the main pipeline (mainline), or an NGL plant
Net Present Value (NPV)	the future stream of benefits and costs converted into equivalent values today. This is done by assigning monetary values to benefits and costs, discounting future benefits and costs using an appropriate discount rate, and subtracting the sum total of discounted costs from the sum total of discounted benefits.
Nominal $	dollars that are not adjusted for inflation; also referred to as current dollars and represents the actual amount of money spent or earned over a period of time
Northstar Unit	the oil and gas leases subject to the Northstar Unit Agreement on January 1, 2005, or as later expanded or contracted.
Off-take Point	a connection location, consisting of necessary valves, flanges and fitting, where gas flows out of a mainstream element, except for a location where gas flows from one midstream element into another midstream element or into the Alaska to Alberta project and is defined in Article 1.35 of the contract.
Open Season	the process by which a pipeline invites prospective shippers to bid for transportation capacity and, after having reviewed the bids, awards to and allocates capacity among prospective shippers.
Outer Continental Shelf	the submerged lands, subsoil, and seabed, lying between the seaward extent of the state's jurisdiction and the seaward extent of federal jurisdiction.
Participant	BP, CP, or EM, and their respective assignees or any other person added under Article 31, excluding the state and its affiliates, except that the state or its affiliates may hold an interest in a participant.
Project Sanction	refers to the point when the state and the project sponsors collectively vote, as members of the entity that would build and operate the pipeline, to proceed or not proceed with the construction of the project. Prior to this collective decision, the state and the board of directors of each of the project sponsors would make independent decisions regarding their

	participation in the project entity and authorizations for expenditure of funds and the borrowing of money for that purpose.
Producer	BP, CP, or EM and their respective assignees under Article 31 in their capacity as a working interest owner of a property.
Prudhoe Bay Unit	the oil and gas leases subject to the Prudhoe Bay Unit Agreement on January 1, 2005, or as later expanded or contracted.
Point Thomson Unit (PTU)	the oil and gas leases subject to the Point Thomson Unit Agreement on January 1, 2005, or as later expanded or contracted.
Qualified Sponsor Group	a group of persons that either: owns or intends to own an equity interest in the project; intends to commit gas that it owns to the project; or holds the permits that the state determines are essential to construct and operate the project; and which group of persons also meets one or more of the following criteria: owns a working interest in at least ten percent (10 percent) of the stranded gas proposed to be developed by the project; has the right to purchase at least ten percent (10 percent) of the stranded gas proposed to be developed by the project; has the right to acquire, control, or market at least ten percent (10 percent) of the stranded gas proposed to be developed by the project; has a net worth equal to at least ten percent (10 percent) of the estimated cost of constructing the project; or has an unused line of credit equal to at least fifteen percent (15 percent) of the estimated cost of constructing the project.
Real $	or constant dollars are values adjusted for inflation; the effect of inflation is removed
Reserves	oil and gas contained in underground rock formations called reservoirs. Proved reserves are the estimated quantities that geologic and engineering data demonstrate can be produced with reasonable certainty from known reservoirs under existing economic and operating conditions. Recoverable reserves are those that can be produced using all primary and enhanced recovery methods.
Tax Gas	means the quantity or volume of tax bearing gas that the state receives under Article 13 of the Contract.
Upstream Facilities	include a facility used by a producer, upstream of a delivery point, designed to explore for, develop, produce, gather, process, handle or treat gas, or hydrocarbon liquids, or by-products associated with that gas or hydrocarbon liquids.

Executive Summary

For a contract negotiated under the Stranded Gas Development Act (SGDA), AS 43.82.010 - 43.82.990, the commissioner of revenue is required to make preliminary findings and a determination whether the proposed contract terms are in the long-term fiscal interests of the state. The State of Alaska has been in negotiation with BP Exploration (Alaska), Inc. (BP), ConocoPhillips Alaska, Inc. (CP), and ExxonMobil Alaska Production, Inc. (EM) (collectively, the Sponsor Group) since January 2004. The outcome of these negotiations is a proposed contract between the state and the sponsor group, which is the focus of this fiscal interest findings and determination.

The parties to the contract have negotiated and agreed, as of May 8, 2006, to 38 of 41 articles pertaining to various terms and conditions that would provide fiscal certainty to the sponsor group and facilitate the construction of a natural gas pipeline. Article 14, Payments in Lieu of Production Taxes, is still being negotiated. In part negotiations are delayed until passage of the Petroleum Profits Tax (PPT) statute currently under deliberation by the legislature. This document had to be transmitted to the printer prior to completion of negotiations for this article. Updates to this document incorporating the final articles will be issued when negotiations are complete.

Preliminary Findings and Determination of the Commissioner

The commissioner of revenue made a specific finding that Alaska North Slope (ANS) gas is stranded. The commissioner also finds that the contract negotiated under the SGDA is in the long-term fiscal interests of the state. The commissioner finds that Alaska stands to benefit in multiple ways from the development of the state's stranded gas resources. These specific benefits include:

- Establishing a significant long-term gas industry in Alaska through the encouragement of exploration and development of new sources of gas and oil within Alaska;
- Generating significant state and municipal revenues over the project's life to meet the state's pending financial shortfall;
- Creating employment opportunities for Alaska residents through the contract's stipulations regarding employment and training opportunities;
- Providing in-state access to ANS gas for homes, businesses, and industrial plants; and
- Generating income for Alaska businesses by providing increased economic opportunities.

The commissioner finds that on balance there will be a benefit realized by the state treasury over the term of the contract. Assuming that the proposed fiscal changes are in place, the benefits[1] of the proposed gas pipeline project to the state treasury are as follows:

- An estimated gain in gas-related revenues to the state and municipalities of $12 billion in net present value;
- An increase in oil-related revenues from to the state and municipalities of $2 billion in net present value, for a total gain of $14 billion ;

Total estimated oil and gas revenues (including projected oil revenues without a gas pipeline) to state and municipalities under the proposed fiscal terms ($35 billion) are comparable to estimated revenues under the 2005 fiscal structure ($34 billion including projected oil revenues); assuming a pipeline is built.

The commissioner also finds that the contract furthers the purpose of the SGDA by maximizing benefits and establishing fiscal terms in advance for the gas pipeline project. Establishing those fiscal terms for the duration of the contract (fiscal certainty) is extremely important to this gas pipeline project. Due to its immense cost and scope, the project is far more sensitive to risk than a smaller scale project. Fiscal certainty is necessary to allow the project to move forward. For this reason, the commissioner concludes that it is in the long-term fiscal interest of the state to provide fiscal certainty over the term of the contract, which could extend for a 45-year period.

Introduction

Under today's regime, the fiscal outlook for the state is relatively good in the near term, but less so into the future. In the long run, the combination of lower crude oil production volumes coupled with increased appropriations will combine to create larger deficits. The current surpluses will likely slide into a deficit in the near term as oil prices and production decline. Under the state's current revenue forecast, the constitutional budget reserve may be depleted by 2011 and oil production ends in 2030. Were the state to have natural gas development and a natural gas pipeline, the long run fiscal outlook would be improved with natural gas production beginning in 2016.

Alaska's Natural Gas Resources

The ANS contains vast reserves of natural gas resources that cannot be sold in the marketplace due to the absence of a transportation system to bring that gas to market. Since oil was discovered at Prudhoe Bay in 1967, there have been numerous attempts to develop and commercialize ANS gas. Until recently, commercialization of ANS gas has not been economically viable due to low market prices and the high cost and risks associated with constructing the infrastructure to transport the gas to market, and competition from other gas resources. Due to current market conditions, federal legislation, the SGDA, and the contract, Alaska is closer than ever to realizing this potential to develop a natural gas industry.

[1] These estimates are based on $5.50 per mmBtu of gas (Chicago city gate) and $35 per barrel of crude oil West Texas Intermediate (WTI) and a discount rate of 6 percent. These values are expressed in real dollars (2005 dollars).

SGDA Framework

The SGDA established a process by which applicants and the State of Alaska can negotiate the fiscal terms associated with gas development and prepare a contract so that a natural gas pipeline project can move forward. The SDGA authorizes the commissioner of revenue to negotiate a contract fixing the fiscal terms or obligations for the development of the stranded gas from state-owned lands.[2] After two years of negotiations, the state has come to such an agreement with the sponsor group. The SGDA requires the commissioner of revenue to make a determination whether the proposed contract terms are in the long-term fiscal interest of the state.

Following the enactment of amendments to the SGDA in 2003, the state began preparing for the process of negotiating a contract. Through the use of expert in-house staff and consultants, the state explored the issues that it was likely to face in negotiations and began developing its substantive positions.

BP, CP, and EM submitted a stranded gas act application in January 2004. After the application was accepted by the commissioner of revenue, the state and the three sponsors began a series of discussions, workshops, and negotiations lasting over two years and culminating in the contract.

Project Description

The project involves building a large-diameter, large-volume natural gas pipeline and related facilities with a design capacity to transport over four billion cubic feet per day (bcf/d) of stranded gas from the ANS to Alaskan and North American markets. This potential volume represents about seven percent of the total U.S. daily consumption of approximately 60 bcf/d of natural gas in 2004. The recoverable known ANS gas resources are estimated to total approximately 35 trillion cubic feet (tcf). To put this amount into perspective, the U.S. consumed about 22 tcf of natural gas in 2004 (EIA, 2005).

The project requires producing approximately 53 tcf of natural gas to operate at capacity over the anticipated 35-year operating life of the gas pipeline. This means producers and other explorers must find and develop an additional 18 tcf of natural gas resources. The potential that sufficient and cost-effective sources of natural gas beyond the known ANS resources may not be found increases the risk of the project. This resource risk makes it important that fiscal certainty be available for a long period of time in order to provide incentives for natural gas exploration and development.

The project entails several components in addition to a natural gas pipeline (see Figure ES-1). Project components include:

- Gas transmission pipelines that would deliver gas to the gas treatment plant (GTP) or the large diameter gas pipeline (mainline) from gas producing properties;
- The GTP that would be located on the ANS and would remove certain impurities from the gas, and compress and chill the gas to meet the specifications required for the large-diameter gas pipeline;

[2] Some stranded gas is on federal and privately owned lands, but fiscal terms for those leases would not be subject to this contract between the state and the applicant.

- The mainline located in Alaska along the Trans Alaska Pipeline System (TAPS) and Alaska Highway that would operate as a high-pressure pipeline with compressor stations at regular intervals;
- A pipeline from the Alaska-Canada border to Alberta with compressor stations at intervals to maintain pressure;
- An Alberta to lower 48 project to export gas from Alberta to markets in the lower 48 states, potentially through a new pipeline, use of existing pipeline capacity, or expansion of existing pipeline systems; and
- A natural gas liquids (NGL) plant that could be located in Alaska, Canada, or the lower 48 states to recover NGL for sale.

The pipeline system has been designed in two segments. The first segment runs from Prudhoe Bay to Alberta, Canada. This segment is a new pipeline of approximately 2,100 miles and would roughly parallel TAPS and the Alaska Highway. The second segment is a 1,500-mile pipeline which may be a new pipeline from Alberta to Chicago. An alternative to building this section of the pipeline would utilize existing pipelines or expansion if it were competitively priced.

Figure ES-1. Alaska Gas Pipeline Project Route Map

Source: ADNR.

As outlined in Table ES-1, the various components of the project proposed by the sponsor group are estimated to cost approximately $21 billion (in 2005 dollars), provide over 6,000 direct Alaska jobs, and take about three years to build. The project cost is a preliminary estimate, subject to revision as the project becomes better defined after completion of the engineering and design work.

Table ES-1. Preliminary Cost Estimates of Project Components

Component	Amount ($ billion, 2005)
Gas Treatment Plant	2.6
Alaska Pipeline (Prudhoe Bay to Canadian border)	5.1
Canadian Pipeline (Alaska border to Alberta)	5.9
Total Cost to Alberta	13.6
Estimated Cost from Alberta to Chicago	7.4
Total Cost to Chicago	21.0

Source: ADOR.

The project cost estimates shown in Table ES-1 do not include the cost of a NGL plant if one is built, or the gas transmission lines, nor do they include the development costs for the Point Thomson Unit (PTU) or other fields that will be required to fill the pipeline. It is estimated that the cost to build a gas transmission line from PTU to the GTP is approximately $600 million, but the length of a gas transmission line into the National Petroleum Reserve-Alaska (NPR-A) is unknown and so is the price.

Summary of the Contract

The contract negotiated and agreed to by the state, BP, CP, and EM contains 41 articles that will provide the fiscal certainty necessary for the project to go forward. Articles that pertain to the contract's major terms and conditions are summarized in the report that follows.

The gas pipeline contract provides for the state to own a 20 percent interest in the following:

1) the large-diameter pipeline;
2) compressor stations and related facilities from the ANS to Alberta;
3) a gas treatment plant; and
4) a NGL plant if one is located in Alaska.

The contract also provides for proportionate state ownership of gas transmission pipelines, facilities to move the gas from Alberta to the lower 48 states, and an option for a transmission line from the NPR-A. Proportionate state ownership will be through state-owned entities established to own or have an ownership option for the project elements.

The contract provides for a period of 45 years of fiscal certainty (approximately ten years until first commercial operation followed by a 35-year operating period) in order to provide a long-term stable investment climate to develop known reserves and stimulate exploration and development of reserves yet to be identified. The state believes the 45-year period of fiscal certainty for gas and a 30-year period for oil is required. The producers and the state anticipate that the Federal Energy Regulatory Commission (FERC) will establish a depreciable life of the pipeline in the range of 30 to 40 years based on both known and potential gas resources. As a result, since the project will take up to ten years to complete, 45 years is a reasonable estimate of the period it will take equity owners to both build the gas pipeline and to recover their investment. The 30-year period of certainty granted for oil coincides with the time that exploration for oil will likely result in finding additional gas reserves needed for the remaining life of the project.

Additional legislation will be introduced that extends these same assurances of fiscal certainty to any party that makes a firm shipping commitment for ANS gas on the pipeline during the 45-year period. This legislation is intended to spur increased exploration and discovery of gas fields.

Guiding Principles

There are a number of important principles that Governor Murkowski identified which were required to be addressed in the contract in order for the project to go forward. These principles include:

- Alaskans deserve a fair share of the revenues;
- Alaskans need access to the gas;
- Future explorers must have access to the gas pipeline;
- The gas pipeline must be expandable;
- The state should own a share of the pipeline; and
- Alaskans deserve pipeline jobs.

Each of these principles is discussed in the following paragraphs.

Alaskans Deserve a Fair Share of the Revenues

Alaskans deserve a fair share of the revenues and the contract achieves that principle. The principle focuses on the balance that must be struck between the state's interests to maximize its revenues and the need to develop a commercially viable project. A fair share of the revenues will enable the project to move forward and the subsequent revenues to the state will support quality education and healthy and safe communities. In addition, approximately 28 percent of the royalty gas sales will go to the Permanent Fund, increasing future Permanent Fund dividends.

Revenue generating elements of the project include royalty gas and gas that the state will take in lieu of cash for the production payment, state ownership in the project, and monetary and impact payments under the fiscal terms of the contract. Taking possession of the gas has implications for the state to ensure that it has sufficient capacity to move its gas to markets in Alaska and elsewhere in North America.

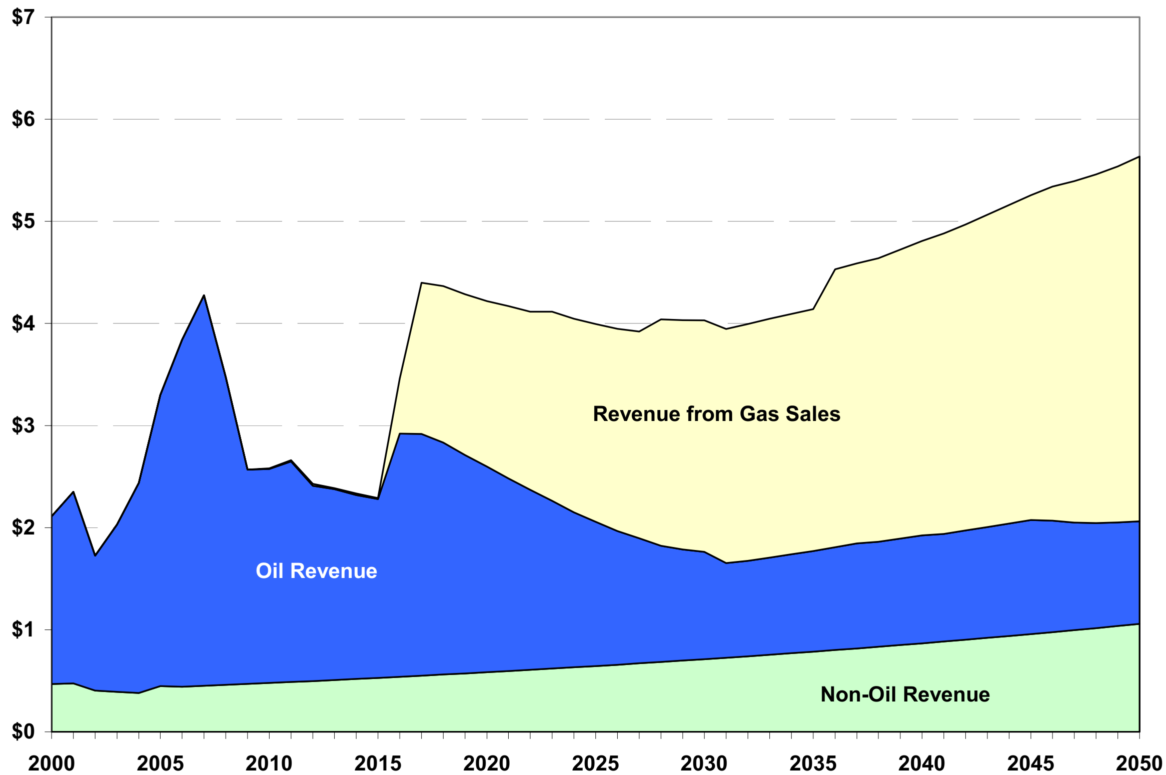
The long run financial outlook shows that the State of Alaska faces mounting deficits without the natural gas pipeline. The pipeline and its associated revenue:

(1) diversifies the state revenue stream; and

(2) transforms the state from a petroleum province to a natural gas province.

Figure ES-2 presents the state's revenue stream assuming prices for oil at price of $35 per barrel for west Texas intermediate crude oil (comparable to $33 per barrel for ANS crude delivered to the west coast of the U.S.) and natural gas at $5.50 per million British thermal units (mmBtu).

Figure ES-2. Alaska Revenues with a Gas Pipeline and PPT



Source: ADOR model.

Notes:

1. Revenues are expressed in billions of nominal dollars; by fiscal year from 2000 to 2050.
2. Price assumptions: ANS oil price of $33 per barrel; Natural gas price of $5.50 per mmBtu (Henry Hub).

Alaskans Need Access to the Gas

Affordable energy is vital to growing a healthy economy throughout Alaska, and new energy sources are critical to the railbelt and southcentral Alaska, as well as interior communities. Access to the gas from the ANS is a key element in meeting these needs. A study conducted on behalf of the Alaska Department of Natural Resources (ADNR) by Econ One (Dismukes, 2002) predicted that in-state gas usage over the next two decades has the potential to increase by approximately 140 bcf, to 367 bcf per year. The report concluded that baseline economic growth represents about 19 percent of this projected increase in gas usage. It is worth noting that an incremental increase or decrease in industrial load would substantially alter the overall consumption picture. For example, even at current reduced production rates of about 40 bcf per year, annual gas consumption at the Kenai ammonia-urea plant is 25 percent greater than gas consumption for the entire Enstar Natural Gas Company distribution system for space heating in southcentral Alaska.

Many areas of the state are not currently served by natural gas utilities, and several current and potential industrial uses could be served by natural gas when the major ANS gas project becomes operational. This gas could be used to meet commercial, industrial, and residential heating needs, as well as providing additional electricity generation capacity.

The possibility of constructing a new NGL processing plant is under consideration. One option would be to construct a large-scale NGL extraction and fractionation plant at an off-take point near Fairbanks in interior Alaska, possibly in conjunction with a lateral spur pipeline designed to deliver ANS gas to in-state markets. The potential for a large-scale petrochemical complex at Fairbanks was found to be unlikely to satisfy basic economic thresholds in a study completed by Muse Stancil (2004a); other alternatives, however, are being studied. One alternative would be to construct a small-scale NGL extraction and fractionation facility designed, in conjunction with a spur pipeline, to serve local and regional in-state markets for certain NGL components such as propane.

The contract contains provisions that build upon the foundation laid by FERC's open season[3] regulations in insuring that in-state needs would be met. FERC requires that the pipeline offer an intrastate transportation rate based on mileage. FERC also requires that the pipeline propose in-state delivery points as determined by a required study of in-state needs. The contract sets out a timetable for completing this study and determines off-take point locations in Alaska to allow-in-state needs to be satisfied. The contract requires the pipeline owners to cooperate with any person wanting to connect to the line for in-state service. The contract also requires that the mainline entity conduct a study of NGL processing opportunities in Alaska.

Future Explorers Must Have Access to the Gas Pipeline

The current estimated technically recoverable ANS gas reserves are not sufficient to fill the capacity of the pipeline for the 35 years of operations envisioned in the contract. Exploration and development of new gas fields are critical to the success of the project. In addition, these new explorers should have the opportunity to have the same fiscal terms as the sponsor group in order to enable them to compete for lease sales on the ANS.

Provisions in Article 8 of the contract encourage exploration by providing for expansion of the pipeline system when future discoveries are made and reserves are identified. These expansions will help ensure that new gas discoveries get to market. In addition, included in the contract is draft legislation which will be introduced in the special session that contains proposed language for a Uniform Upstream Fiscal Contract Act. This act would enable

[3] The process by which a pipeline invites prospective shippers to bid for transportation capacity and, after having reviewed the bids, awards to and allocates capacity among prospective shippers.

producers that are not parties to this proposed contract to achieve the same fiscal certainty on oil and gas leases on the ANS. This uniform upstream fiscal contract would include provisions identical in substance to numerous key provisions of the contract and would require that signatories to the contract agree to work commitments requiring diligent exploration efforts and to making firm transportation commitments for the shipment of gas that results from their development efforts.

The Gas Pipeline Must be Expandable

New discoveries of natural gas must get to market so that Alaska realizes maximum benefit from the gas pipeline. Alaska's potential gas resources may exceed 200 tcf, a vast amount relative to the level of known resources. With increased exploration activity, additional commercial resources are expected to be discovered and the pipeline must be capable of expansion to achieve maximum benefit for the state and its residents.

Expansion issues have been addressed in three ways. Section 105 of the Alaska Natural Gas Pipeline Act (ANGPA) gives FERC the power to order expansion of an Alaska gas pipeline if certain conditions are met and special procedures followed. FERC also addressed expansion issues in the open season regulations requiring low-cost expansion. Finally, the state negotiated a special expansion article (8.7) in the contract that created rights for the state to initiate an expansion if a person is unable to secure capacity from other shippers or the pipeline or through a voluntary expansion by the pipeline entity. If any person, including the state, is unable to obtain expansion capacity either from another shipper or from a voluntary expansion of the pipeline by its owners, the state may issue an expansion notice to the owners of the pipeline that ultimately requires them to file an expansion application with the FERC, provided certain conditions are fulfilled and processes followed. The proposed design also allows for low-cost expansion.

The State Should Own a Share of the Pipeline

State ownership of the pipeline and other facilities is necessary for the project to be an economically competitive option in the portfolios of the sponsor group. Under the contract, the state improves the project economics by co-investing rather than by providing financial incentives to the producers that would in turn reduce state revenues. In addition, state ownership provides a stable flow of revenue to the state from the investment returns in the project. The contract also provides for several payments in lieu of taxes to the state and municipalities that are based on throughput and will not vary with price. Lastly, the contract will expedite construction of a natural gas pipeline project.

State ownership will create economic benefits for the state through providing a stable, steady revenue stream. In addition, the state pipeline company will participate in decisions related to project development as a member of the limited liability corporation (LLC) or corporations that own the pipeline. The state's participation will advance the project by reducing the magnitude of the investment the producers will make in the project, thereby making the project more attractive to them.

State ownership alone does not entitle the state to ship its gas via its share of the pipeline, nor will the state own a segment of the gas pipeline capacity that it can independently offer for bid. All of the pipeline's capacity will be offered by the mainline entity (which the state would be a member of) to potential shippers during the open season, and neither the state nor other members of the mainline entity has preferential rights to any capacity.

Alaskans Deserve Pipeline Jobs

New jobs would be created during the pipeline's construction; it is, however, expected that the number of workers required for this construction project will be greater than what the Alaska workforce could supply. Therefore, a successful Alaska hire program should mean that qualified Alaskans who want a job on the pipeline project can get one, rather than requiring that all or a majority of the jobs go to Alaskans (Anchorage Chamber of Commerce, 2006b, Volume 2). As specified in the contract, Alaskans would be considered for the permanent jobs that will be available after the construction period.

Construction of the proposed pipeline and a gas treatment facility would increase employment in Alaska by an estimated 9,300 direct, indirect, and induced jobs during peak construction periods.[4] Many of these jobs will be seasonal and temporary in nature. A smaller but significant number of permanent employees would be needed to operate the mainline and other project components. Operation of the pipeline and gas treatment facility following construction is anticipated to directly employ about 100 workers. Indirect and induced jobs would also be created in various sectors of the economy during operations as a result of related spending by the project entities, state and local governments, and households.

The contract requires that the mainline entity spend a combined total of $5 million to fund workforce training programs and activities in Alaska. Additionally, the ANGPA provides grants of up to $20 million for an Alaska pipeline training program to recruit and train Alaskans, including the design and construction of facilities located in Fairbanks to support this training. The contract requires the mainline entity to work with the state, including the department of labor, to develop these or other programs that could increase employment opportunities for Alaska residents.

Other Major Issues

In addition to the six guiding principles, several other major issues are addressed in the contract:

- Royalty gas and tax gas;
- Predictable and durable terms for Alaska's share;
- Work commitments;
- Alignment;
- Dispute resolution;
- Point Thomson Unit;
- Legal issues; and
- Transportation issues and highway use agreement.

The following subsections address each of these items.

[4] Peak construction would occur in January, February, and March of 2010 through 2012.

Royalty Gas and Tax Gas

The state will take possession of its royalty share of natural gas and the gas production payment (tax gas). In doing so, the state would give up the rights 1) to argue under the lease or production tax regulations that field and marketing costs are not deductible from certain leases' royalty or tax share, 2) that the state has the right to switch from taking cash to taking gas for royalty, and 3) that the state can take the "higher-of" various measures of value when taking royalty or severance tax in cash. Also, in taking delivery of the gas, the state assumes ownership, title, financial responsibility, and risk of loss for its tax gas and royalty gas. The sharing of risk between the producers and the state is intended to improve the economic feasibility of the project.

Predictable, Durable Terms

The 45-year period (assuming a 10-year ramp up and 35 years of operations) of fiscal certainty is intended to provide a long-term stable investment climate and predictable and durable terms for Alaska's share of the project income. Fiscal certainty will help stimulate exploration and development of resources not yet identified, and will lock in the fiscal requirements that will frame the development of the project. Otherwise, the benefits of fiscal certainty on gas production, property, and income could be eroded or offset by changes in oil taxation during the life of the project.

Work Commitments

Work commitments are addressed under Article 5 of the contract, and participants are required to advance the project "as diligently as is prudent under the circumstances" until project sanction.[5] This performance standard is defined in the contract as "diligence." The three requirements that the participants have committed to under Article 5 as they work toward project sanction are:

- Project initiation within 90 days of the effective date of the contract;
- Preparation of a qualified project plan; and
- Preparation and submittal of an annual report that describes the progress made to build the project.

Because of the very large cost of the project and the extended time before gas starts to flow through the pipeline, a prudent investor would not commit billions of dollars so early in the project's life cycle. Recognizing this reality, the state sought a meaningful way to move the project towards project sanction. The work commitments obligate the project sponsors to advance towards that goal, but also recognize that unforeseen events could delay or even, at the extreme, prevent the project.

[5] Project sanction refers to the point when the state and the project sponsors collectively vote, as members of the entity that would build and operate the pipeline, to proceed or not proceed with the project. Prior to this collective decision, the state and the board of directors of each of the project sponsors would make independent decisions regarding their participation in the project entity and authorizations for expenditure of funds and the borrowing of money for that purpose.

Alignment

Alignment refers to the parties' recognition that the state's participation in the project has multiple benefits. This participation improves the project economics to the sponsor group and causes the state and the sponsor group to be aligned with a goal of building and operating a successful project. For example, the state will be taking possession of its royalty gas and production payment as gas, not cash, so likely disputes about the value of that gas would be avoided. Because Alaska will have the responsibility to market its own gas, the state also negotiated for special transportation rights (Article 10) to ensure that it would have access to capacity on the pipeline to move its gas to market. These rights ensure that Alaska can move its own gas to market on equal footing with the producers.

Dispute Resolution

The state and the producers have been involved in a number of protracted and expensive legal disputes over oil prices, taxation, audits, and similar items for oil production and the TAPS. To avoid this situation with the gas project, Article 26 of the contract calls for mandatory dispute resolution. The state, recognizing the value of this clause, also waives its immunity to suits to enforce the mandatory dispute resolution procedures and the article.

Point Thomson Unit

The Point Thomson Unit (PTU) will provide about one-third of the initial gas volumes to the project, and is an important factor in the economic viability of the gas pipeline project. The contract commits the PTU leaseholders to provide a minimum of 500 million cubic feet per day (mmcf/d) of PTU gas to the project. The producers must also apply to the Alaska Oil and Gas Conservation Commission for issuance of pool rules to authorize the rate of gas extraction (off-take) from the PTU within six months of the effective date of the contract.

Legal Issues

Legal issues discussed in the contract include the ability of the state to enter into a contract, state tax powers, and issues related to competition and antitrust. The SGDA, and the contract proposed under it, present an important legal issue concerning whether the state can enter into a contract that will establish the tax obligations of the sponsor group for a fixed period of time. If the contract is valid, the terms would be binding on the state and future legislatures. Because of the fundamental importance of this issue, the attorney general provided legal advice that Article IX, sections 1 and 4, of Alaska's constitution permits the state to enter into a contract with the sponsor group.

Transportation Issues

Lastly, construction of the pipeline will place heavy demands on Alaska' surface transportation system. The intensity of freight movement during pipeline construction will increase truck volumes and freight tonnages to a level above and beyond roadway life-cycle design as well as, in specific instances, the physical capacity of the infrastructure. To fully realize and mitigate the potential impacts of project construction on the state's transportation system, the department of transportation and public facilities will enter into a highway use agreement (HUA) with the mainline entity. The HUA will address necessary infrastructure improvements; cost share principles for capital projects; compensation for increased maintenance and operations; airport facility safety and security issues; roadway safety, traffic control, and congestion mitigation; permitting truck weight and size; right-of-way access and encroachment; and utility relocation. The cost of system rehabilitation after construction may approach $800 million.

SGDA Principles and Framework

This section provides an analysis of the fiscal principles put forth by the SGDA, and a comparison of alternative pipeline proposals. These six principles are:

(1) The terms should improve the competitiveness of the project in relation to other development efforts aimed at supplying the same market;
(2) The terms should accommodate the interests of the state, affected municipalities, and sponsors under a wide range of economic conditions, potential project structures, and marketing arrangements;
(3) The combined share of the economic rent to the state and affected municipalities should be progressive;
(4) The combined share of the economic rent to the state and the affected municipalities should be relatively lower in the earlier years than in the later years;
(5) The share of the sponsors should compensate the sponsors for risks under a range of economic circumstances; and
(6) The terms should provide the state and affected municipalities with a significant share of the economic rent when discounted to present value under favorable price and cost conditions.

Section 43.82.210(b) of the SGDA requires the commissioner to develop terms for a stranded gas contract that are balanced on the basis of the fiscal principles cited above.

The goal of the SGDA is to make the project more competitive so that it is likely to proceed after a period of feasibility studies and regulatory approvals. At the same time, the SGDA requires the commissioner to structure the fiscal terms in such a way that they provide significant revenues to the state and affected communities under favorable economic conditions.

The SGDA also provides guidelines for structuring the fiscal terms. The SGDA prescribes that the fiscal share of project revenues that Alaska receives should increase if prices are higher and costs are lower than expected, while the state and the municipalities should take a smaller share in the early years and a larger share in later years.

The contract complies with the balance of principles required under the SGDA; in particular, the contract makes the project more competitive. The Alaska gas project was compared on the basis of profitability with 60 other large oil and gas projects in the world. Under the royalty and tax structure that existed at the end of 2005, the profitability of the Alaska gas project is less than average compared to competing projects, and the internal rate of return (IRR) is low. Due to the large size of the project, however, the absolute size of the profits and net cash flow are very favorable.

The proposed contract fiscal terms result in a higher level of profitability than under the 2005 royalty and tax structure. For a project delivering gas to Alberta, the rate of return improved from 11.8 percent with the 2005 fiscal structure to 14.0 percent with the proposed contract terms. This increased rate of return was achieved through risk sharing and participation by the state. The state takes possession of all gas royalties and also converts the production payment into gas. This results in the state receiving almost 20 percent of all the gas from the project in the initial years.

The state will assume the obligations to transport and sell its share of the gas. The state will also participate in 20 percent of the investments in the GTP and pipeline, and certain other facilities. Under this situation, the sponsors jointly invest 80 percent of the project capital costs and are able to transport 80 percent of the gas, rather than providing 100 percent of the project capital cost and transporting 80 percent of the gas. With state participation, the project becomes more profitable for the investors as they invest less and receive the same net revenues.

At the same time, the state receives a steady stream of pipeline tariff revenues as a result of its investment, which is not affected by changes in gas prices. In addition, the state and the municipalities also receive a stable stream of revenues from in-lieu-of property tax payments that are based on throughput. Thus, the contract is favorable to the sponsors, the state, and the affected municipalities by improving the rate of return for the sponsors without yielding any significant revenues received by the state and municipalities.

The contract offers a better approach than the traditional way of making a project more competitive by lowering the royalties and taxes that need to be paid. This traditional method is not a viable option for Alaska. In order to achieve the 2.2 percent increase in the rate of return noted above, the royalties and taxes would have to be lowered to a point that the contract would become unacceptable to the state.

As a result of the proposed contract, the annual revenue (in real 2006 dollars) to Alaska will be significant under a range of natural gas prices (Chicago city-gate):

- At low gas prices of $3.50 per mmBtu, revenues total about $1 billion per year;
- At average gas prices of $5.50 per mmBtu, revenues total about $1.7 billion per year; and
- At high gas prices of $8.50 per mmBtu, revenues total about $2.7 billion per year.

It should be noted that Alaska will still receive substantial total revenues even if gas prices are relatively low. Under low gas prices, the proposed contract is favorably balanced for Alaska and is less so for investors. The terms result in favorable revenues if gas prices are high and costs are average.

The negotiated terms are very competitive from an international point of view. Jurisdictions that transport their gas over large distances, either by long distance pipeline or as liquefied natural gas (LNG), necessarily have to adjust their terms to overcome these high transport costs. The overall take that governments achieve in these circumstances is about 48 to 57 percent. Alaska fits right in the middle of this range.

Fiscal certainty is a crucial element of the contract. In the absence of fiscal certainty established with the stranded gas contract, it is possible that adjustments would be made in the future by a legislature acting in good faith that would erode much of the gas profits originally required to make the project competitive. At the commencement of project operations, all capital expenditures of the sponsors will have become sunk costs. At that point, the sponsors no longer have the option to not proceed with the project, even if faced with decreased profitability due to changes by the legislature.

In other words, a lack of fiscal certainty would expose investors to:

- Significant possible erosion of value to the point where the project becomes unattractive, when taking into consideration the capital invested; and
- Very significant exposure to downside price and cost overrun conditions.

For such a large project, investors simply cannot accept this risk. Fiscal certainty is required if this project is to be realized.

Evaluations Section

Three alternative projects are examined to determine which is in the best interest of the state of Alaska. The three projects are the following:

(1) A 4.5 bcf/d gas pipeline that parallels the TAPS to Delta Junction, Alaska, and then follows the Alaska Highway to Alberta, Canada. This is the project proposed by the sponsor group and is referred to as the ALCAN project.

(2) An Alaska LNG project based on the Alaska Gasline Port Authority (AGPA) proposal that includes a 4.0 bcf/d pipeline from Prudhoe Bay to Valdez, Alaska, where gas is liquefied and shipped as LNG to Pacific ports. This project is identified as the LNG project.

(3) A Y-line project with a 4.5 bcf/d pipeline from Prudhoe Bay to Delta Junction, where the pipeline splits into a 3.0 bcf/d pipeline to Alberta, Canada, and a 1.5 bcf/d pipeline to LNG facilities in Valdez. This project is referred to as the Y-Line project.

While numerous analyses were conducted in the complete evaluation, four indicators are presented here:

- Net present value (NPV)—to the state, local governments, and the sponsor group;
- Gas revenue contributions to Permanent Fund, 2016-2050;
- Wellhead value after tariff; and
- Natural gas losses.

The price assumption used is a mid-range price of $5.50 per mmBtu of natural gas at the Henry Hub, increasing by two percent per year. The results of the analysis are presented in Table ES-2.

Table ES-2. Economic Indicators for Three Natural Gas Projects

Metric	ALCAN	LNG	Y-line
Net present value (Billions of nominal $)			
State @ 5% discount rate	$28.0	$20.0	$22.5
Sponsors @ 10% discount rate	$18.5	$10.3	$10.7
Local governments @ 5% discount rate	$1.9	$5.3	$4.3
Gas revenue contributions to APFC, 2016-2050 (Billions of nominal $)	$30.7	$20.1	$17.8
Wellhead value after tariff (per mmBtu)	$3.01	$2.50	$2.73
Natural gas losses (Percent)	11.30	17.60	11.50

Source: ADOR model.

Examining Table ES-2 reveals that the largest NPV to the state and the sponsor group comes from the ALCAN project. Local governments have the largest NPV under the LNG project. Thus, much of the value from developing the natural gas is transferred to the local governments under the LNG and Y-Line projects.

Natural gas losses are lowest with the ALCAN project primarily because the LNG project has losses associated with an 800-mile pipeline, plus losses associated with the liquefaction process and marine shipping.

The highest wellhead value after the tariff accrues to the ALCAN project due to its superior economics. The total revenues to the Permanent Fund from 35 years of gas production (excluding oil revenues) would be about $30.7 billion with the ALCAN project versus $20.1 billion with the LNG project and $12.8 billion for the Y-Line project. This occurs because there is more revenue to the state under the ALCAN project (about 28 percent of all gas royalties will be deposited into the Permanent Fund). In short, the producers will realize greater profitability with an ALCAN pipeline because this project achieves significant economies of scale that lower tariffs and other processing costs. The Chicago market is also likely to attain a premium price for natural gas while the west coast of North America would likely have a lower price were it to receive large natural gas supplies from an LNG project.

Given the premium received by the producers from building their own pipeline, it is unlikely they would consent to sell gas to another project without coercion. Oil and gas leases are binding contracts allowing the leaseholder to produce oil and gas as long as they abide by the lease terms. An attempt to extinguish the producers' interest in ANS gas by taking back leases through legislative or legal means would likely result in protracted litigation, delaying the start of the LNG or Y-Line projects. The time period required for others to obtain the leases from the oil and gas companies is assumed to be five years in the evaluation, although the time period could exceed ten years.

Delaying the project by five years results in lower NPV estimates for the LNG and Y-Line projects. Since a one year delay reduces the NPV of the LNG project by $700 million and a one year delay reduces the NPV for the Y-Line project by $800 million, it is not surprising that both projects have lower NPVs than the ALCAN project. Even if non-discounted revenue streams are used, the LNG and Y-Line projects have less value to the state. The reasons include the following:

- The LNG option has about 50 percent higher natural gas losses compared to the ALCAN;
- Lower market prices for the LNG project. This project would ship LNG to the west coast of North America, which is not equipped with sufficient infrastructure to transport the natural gas eastward. The result would be excess supplies that would reduce the price.

In addition, it is not clear if re-gasification terminals could be constructed on the west coast of North America or if the LNG or Y-Line projects could get LNG tankers constructed that meet U.S. laws and requirements for coastal trade.

Gas Pipeline Applications

The state received several applications including:

- Sponsor group of BP, CP, and EM;
- TransCanada Corporation; and
- Alaska Gasline Port Authority (AGPA).

The sponsor group's application was approved by the state on January 23, 2004, and they entered into a reimbursement agreement, as required under the SGDA. It is through such an agreement that an applicant shares in part of the costs to process the application. The sponsor group's application is the focus of this fiscal interest findings and determination.

Other SGDA applicants included:

- Enbridge, Inc., which submitted an application in April 2004 that was accepted by the state. However, Enbridge, Inc. did not enter into a reimbursement agreement with the state and as a result negotiations regarding a contract have not been conducted.
- MidAmerican Energy Holdings Company and MEHC Alaska Gas Transmission Company, LLC (collectively MAGTC), which submitted an application on January 22, 2004. The application was accepted by the state, but MAGTC did not enter into a reimbursement agreement with the state. MAGTC withdrew its application in March 2004.
- TransCanada submitted an application under the SGDA on June 1, 2004. The state approved TransCanada's application on June 16, 2004, and entered into a reimbursement agreement on August 26, 2004. TransCanada and the state had discussions over major principles relating to their application. The state and TransCanada achieved consensus on most major issues and started to work on terms of a contract. The negotiations were discontinued when the state decided that it was in its interest to negotiate a contract with the sponsor group as they had the rights to the ANS gas which would lead to more timely development of an Alaska gas pipeline. TransCanada has been granted important rights and easements in Canada for a natural gas pipeline to transport Alaska gas to the lower 48 states. It is therefore possible that TransCanada could participate in the Canadian portion of the project.

- The AGPA submitted its application on February 27, 2004, and, after determining that its pipeline project did not require the potential benefits provided by the SGDA, withdrew its application and entered into a protocol with the state in May 2004. AGPA subsequently resubmitted an application on March 30, 2005, to allow for potential negotiations of the royalty and several tax obligations by gas producers through an AGPA project. The commissioner of revenue approved the application on the condition that AGPA show proof that it meets one or more of the sponsor qualification criteria in the SGDA as specified in AS 43.82.110(2)(A) – (E).[6] AGPA did not meet the conditions listed in the ADOR conditional acceptance letter; therefore, that application was never approved and time to submit a new application has expired. ADOR no longer has an AGPA application before it on which to act.

  AGPA originally proposed a stand-alone project with a LNG facility at Valdez. The project description has changed over time and the most recent project entails a 48-inch gas pipeline parallel to the TAPS from Prudhoe Bay to Delta Junction, at which point the pipeline splits. One pipeline, with a capacity of three bcf/d, would run from Delta Junction to the Alaska-Canada border and be built in proximity to the Alaska Highway. The other line would extend to Valdez, with an initial capacity of one bcf/d to Valdez, capable of expansion to 3 bcf/d. A 125-mile 0.5 bcf/d spur line would also be built from Glennallen to Palmer to connect into the Enstar gas distribution system.

The Alaska Natural Gas Development Authority (ANGDA) did not submit an application but is working with all parties to develop a natural gas pipeline and ensure access to gas for Alaska residents and businesses. ANGDA was created by a voter referendum in 2002 to provide one or more of the following services: acquisition and conditioning of ANS natural gas; design and construction of the pipeline system; operation and maintenance of the pipeline system; design, construction, and operation of other facilities necessary for delivering the gas to market and to Southcentral Alaska; and the acquisition of natural gas market share sufficient to ensure the long-term feasibility of the pipeline system project.

Recently, in response to Governor Murkowski’s stated goal to ensure that ANS gas is available to southcentral Alaska, the ANGDA has focused on a proposed Glennallen to Palmer spur line. On April 4, 2005, the ANGDA submitted an application to the state for a “conditional use” right-of-way lease for a pipeline connecting Glennallen to the southcentral Alaska natural gas distribution system. The commissioner of natural resources issued a proposed decision for the right-of-way lease on February 24, 2006, in which he determined that the lease was in the public interest if the terms and conditions of the lease are met. If the proposed sponsor group pipeline is built, ANGDA will extend its spur line concept to extend from Delta Junction to Palmer to ensure that southcentral Alaska has access to ANS gas.

[6] (A) owns a working interest in at least 10 percent of the stranded gas proposed to be developed; (B) has the right to purchase at least 10 percent of the stranded gas proposed to be developed; (C) has the right to acquire, control, or market at least 10 percent of the stranded gas proposed to be developed; (D) has a net worth equal to at least 10 percent of the estimated cost of constructing a qualified project; (E) has an unused line of credit equal to at least 15 percent of the estimated cost of constructing a qualified project.

Mitigating Project Risk

Any project of this magnitude has inherent risk factors, and the state must consider these in assessing if this contract is in the fiscal interest of the state. Four broad categories of risk are associated with the project:

- Economic Risk. These are associated with building, operating, and maintaining the project (cost overruns and completion risk), market-related conditions such as commodity prices and competition from foreign sources, and environmental risks.

  Under the proposed contract, the cost overrun risks are shared proportionately between the state and the producers. If cost overruns occur, the price of the gas at the wellhead will go down in approximately the same ratio for both parties, but the return on investment from the pipeline may increase, thus offsetting some or all of the cost overrun.

  Completion risk is inherent to any large-scale project such as the natural gas pipeline that may be delayed or not completed. This risk can be mitigated by rigorous front-end engineering, planning, permitting, and communications to ensure that the risks, challenges, and uncertainties facing a project are fully understood.

  Commodity price risk is associated with the potential that future natural gas prices in the lower 48 states might be too low to recover all pipeline and production costs, along with an adequate rate of return. Price risk may be due to inherent volatility or competition from other energy sources. Price risk can be mitigated through a wide range of gas sales, long-term contracting arrangements, and hedging mechanisms.

- Resource Risk. This risk concerns finding insufficient gas reserves to sustain the project throughout its useful life.

  The state and producers would proportionately share the resource risk of an under-utilized pipeline. The state must rely upon other producers to produce gas from undiscovered reserves to mitigate the risk of under-utilized capacity. In order to encourage further exploration and development of currently undiscovered gas, the terms of this contract will be available to other potential producers operating in the ANS to ensure that other future producers and transporters of gas are provided terms equal to the current contract signatories.

  In addition, future exploration and development will be encouraged by means of investment credits. The PPT will provide additional incentives for future exploration to help mitigate the risk of investment.

- Social Risk. This includes the international, national, regional, and local political issues, as well as the risk of short-term social disruptions associated with economic booms.

  Under the proposal contract terms, local municipalities and unincorporated communities will be compensated with impact payments to mitigate local economic and social impacts in communities that may be economically affected by the project but will not be able to tax the project.

A large portion of the project will be in Canada and the potential benefits to Canada such as a larger and more efficient Alberta market hub, greater and more efficient utilization of Canada's existing pipeline infrastructure, opportunities to sustain and enhance Alberta's petrochemical industry, and increased development of Alberta oil sands resources will help to mitigate potential social risks in that country.

- *Force Majeure*. *Force majeure* events are unavoidable events such as natural disasters that result in the inability of a party to perform or deliver contractual obligations.

  The contract specifies the steps the parties can take in response to such events including the suspension of obligations. The parties are required to act with diligence to alleviate the *force majeure* event.

Gas Pipeline Financing

Once completed, the project will provide substantial economic benefits to the state and its citizens. While project costs are likely to exceed $21 billion, the projected economic benefits to the state outweigh the projected costs and liabilities to be incurred by the state in connection with the project. This section discusses, in general terms the ownership and corporate structure for the project, the options currently under consideration by the state and the sponsor group for financing project costs, and the state's options for funding its share of equity contributions for the project.

The state would have a 20 percent ownership stake in the project. Given the expected cost of $21 billion for the entire project, the state would contribute over $4 billion while the producers would contribute over $16 billion. The preferred option at this time is to

1. pursue debt financing that uses a traditional project financing structure with the mainline entity as the borrower and which takes advantage of the federal department of energy (DOE) loan guarantee, and to
2. fund its equity contributions with direct appropriations (i.e., cash).

This conclusion is subject to change as the equity arrangements with the sponsor group are finalized, the project is further developed, and discussions with financial institutions, credit rating agencies, the Alaska Permanent Fund Corporation, and the DOE, among others, progress. A finance plan report is included in Appendix F.

The state anticipates that a majority of its share of project costs will be financed, most likely pursuant to a financing arrangement in which the entity that will own the pipeline segment within Alaska borrows up to 80 percent of estimated project costs with only "limited recourse"[7] to the state and the producers during the construction phase for repayment of the loans and other obligations. After project completion, lenders would look solely to the pipeline entity's assets and revenues for repayment of the debt, without recourse to the state or the sponsor group. It is anticipated that the impact on the state's borrowing capacity, and

[7] A lending arrangement where the lender is permitted to request repayment from the sponsor if the borrower fails to meet their payment obligation provided certain conditions are met. Generally, limited recourse only applies to a specific and limited amount.

its cost of capital and credit rating under this financing structure will be considerably less than if the state were directly borrowing 20 percent of project costs.

The state plans to approach the financial markets in concert with some or all of the producers so as to obtain the best financing terms available and seek financing with a debt/equity ratio of 80/20 in order to obtain the lowest cost of capital and tariff. The state also plans to utilize the DOE guarantees available under the ANGPA, if the final terms negotiated with DOE are acceptable, to lower the cost of borrowing and increase the likelihood that the state and the producers can finance 80 percent of estimated project costs.

The state anticipates that lenders will make their loans based on the expected cash flow from operation of the pipeline entity rather than from the creditworthiness of the sponsors of the project. In analyzing the expected cash flow, key issues will include (1) the creditworthiness of the natural gas shippers who will be affiliates of the state and the producers, and whose combined financial credit underpins the expected revenue stream from the shipping contracts; (2) the strength of the terms of the shipping contracts; and (3) regulatory matters, including permitted recovery of capital costs and rate of return on capital under a FERC-approved tariff for the transportation contracts.

It is anticipated that lenders will not accept completion risk on the project, and will require completion guarantees from the state (or the producers in its stead) and the producers. Lenders will typically expect to see (1) a comprehensive guarantee of debt service prior to the completion of the project; (2) an obligation by the state and the producers to invest their equity in required proportions, either up-front, pro rata with the senior debt, or, less commonly, at least by the completion date, so that at the completion date the debt to equity ratio is at the agreed level; and (3) a commitment to fund cost overruns. The state and the producers will seek to mitigate such risks by, among other things, seeking fixed price, turnkey engineering, procurement and construction contracts, sound project management with the producers, and by arranging, either at construction commencement or at a later date if they determine that cost overruns are likely to be incurred, supplemental financing for a portion of overrun costs.

The state’s finance goals include the following (which the producers share, to varying degrees):

(1) limit the state’s liability (whether such liability results from provision of completion support or otherwise) for the funds borrowed for construction of the project so as to mitigate the impact the project will have on the state’s borrowing capacity (and, therefore, its cost of capital and its credit rating);

(2) approach the market in concert with some or all of the producers so as to obtain the best financing terms available;

(3) utilize the DOE guarantees if the final terms of such DOE guarantees negotiated with DOE are acceptable to lower the cost of borrowing and increase the likelihood that the state and the producers can finance 80 percent of estimated project costs; and

(4) seek financing with a debt/equity ratio of 80/20 so as to obtain the lowest cost of capital and tariff applicable to the firm transportation contracts over the long run.

Based on its analysis of the information currently available to it (including the recommendations of the financial advisors), the state's preferred approach to financing the project at this stage is to undertake a project financing with the mainline entity, Alaska Gas Pipeline Company (AGPC) as borrower. The state believes that this finance structure would allow it to successfully achieve its main finance objectives described in the preceding paragraph.

Steps to Move the Project Forward

The execution of the gas pipeline contract will launch a series of steps that will move the project forward:

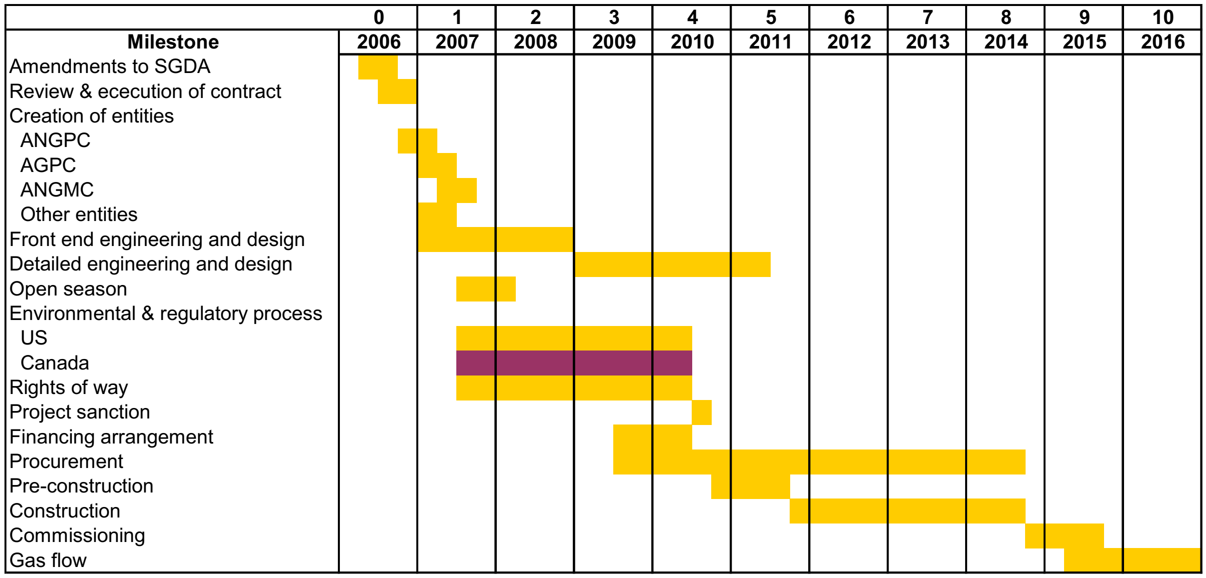
- Legal entities responsible for the pipeline and gas treatment plant will be formed and will initiate project planning and fieldwork (early in year one, see Figure ES-3);
- Project entities will plan for and conduct the open season to solicit the submission and execution of binding agreements for firm shipping commitments on the pipeline. A parallel effort will be undertaken to begin collecting the field data that is necessary for the environmental reports and the many state and federal permits required for the project (latter half of year one);
- Additional engineering and design will be undertaken to support the regulatory process (years two and three), and moving to detailed design after the field data is collected and analyzed (years four and five);
- An application for a certificate of public convenience and necessity will be submitted to and processed by FERC. As part of this process, an omnibus environmental impact statement will be prepared. Similar steps will be required for the pipeline in Canada (years two through four).

After issuance of the necessary certificates of public convenience and necessity by FERC and the National Energy Board (NEB) of Canada, and confirmation of the financing arrangements, the state and the producers will consider whether to sanction the project.[8] If a decision is made to proceed, the project sponsors will undertake procurement and other pre-construction activities following project sanction and then construct the pipeline.

The project timeline is described in Figure ES-3. Developing the government framework and project planning are both expected to take one year to accomplish. Permitting and engineering activities are expected to take about five years to complete, while construction activities would take four years. Gas delivery is expected to begin ten years after the government framework has been established.

[8] Project sanction refers to the point when the state and the project sponsors collectively vote, as members of the entity that would build and operate the pipeline, to proceed or not proceed with the project. In connection with this collective decision, the state and the board of directors of each of the project sponsors would make independent decisions regarding their participation in the project entity and authorizations for expenditure of funds and the borrowing of money for that purpose.

Figure ES-3. Conceptual Project Timeline



This preliminary fiscal interest findings and determination is just one step in the process of developing a natural gas pipeline, but an important and necessary one. Public review and comment on these preliminary findings and determination, and the associated contract, is the next step in the process. The administration will hold public meetings around the state to inform state residents and solicit their opinions. Following the public comment period, the commissioner of revenue will consider necessary changes to the contract, seek modifications to the contract if necessary, and issue a final findings and determination for review by the legislature and the governor. If the legislature approves the contract it will be forwarded to Governor Murkowski for his signature.

Comments on this fiscal interest finding and determination and the contract should be submitted to the state at www.gaspipeline.alaska.gov.

1 Background

The Alaska North Slope (ANS) contains vast reserves of natural gas resources that cannot be sold in the marketplace due to the absence of a transportation system to bring the gas to markets in North America. Since oil was discovered at Prudhoe Bay in 1967, there have been numerous initiatives to develop and commercialize ANS gas; however, until recently, commercialization of ANS gas has not been economically viable due to low market prices for natural gas, the high cost and risks associated with constructing the infrastructure to transport the gas to market, and competition from other gas resources that achieve lower costs at the market. Due to current market conditions, federal legislation, the Stranded Gas Development Act (SGDA), and the contract, Alaska is closer than ever to realizing this potential to develop a natural gas industry.

The SGDA established a process by which applicants and the State of Alaska could negotiate the fiscal terms associated with gas development and develop a contract so that a natural gas pipeline project could move forward. The SDGA authorizes the commissioner of revenue to negotiate a contract fixing the fiscal terms or obligations for the development of the stranded gas from state-owned lands.[9] After two years of negotiations, the state has an agreement in principle with the three members of the sponsor group: BP Exploration (Alaska), Inc. (BP), ConocoPhillips Alaska, Inc. (CP), and ExxonMobil Alaska Production, Inc. (EM). These producers are referred to as the sponsor group. The SGDA requires the commissioner of revenue to make a determination whether the proposed contract terms are in the long-term fiscal interest of the state.

This background section provides information on natural gas resources and prices, the history of attempts to build an Alaska gas pipeline, and a discussion of the SGDA and the process involved in attaining a contract. This section also describes the state's guiding principles and development concept for the future, the negotiation process with the sponsor group, and the steps and challenges involved in realizing an Alaska gas pipeline project.

1.1 Alaska's Long Run Fiscal Outlook

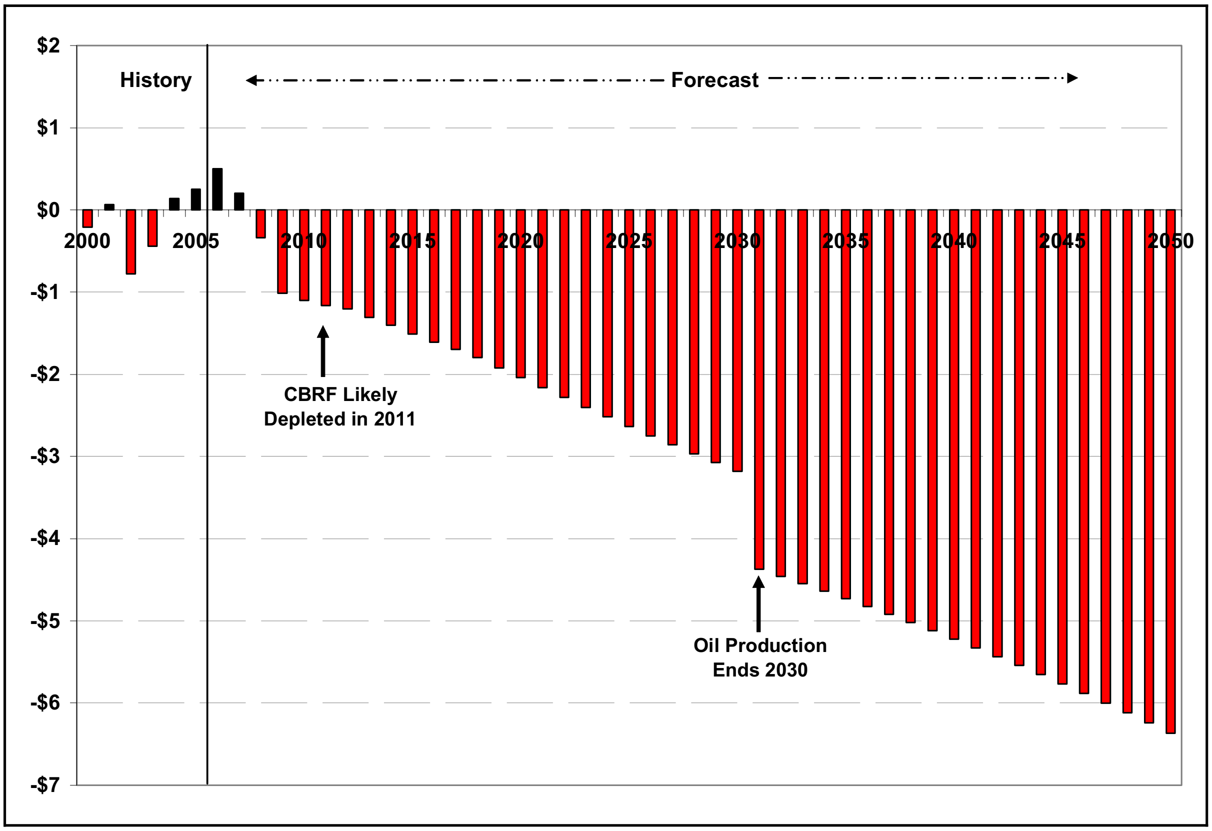
The state will face a difficult financial environment after 2009. The combination of increased debt, rapidly growing retirement liabilities and increasing Medicaid payments causes state appropriations to increase while declining oil production causes oil revenues to decrease. The combination puts pressure on the state finances. The development of a natural gas pipeline provides an opportunity to reduce the potential cumulative deficit by two-thirds—but will not solve the state's long term fiscal imbalance.

The fiscal outlook for the State of Alaska looks good in the short term, but, without the gas line and enhanced oil production encouraged by tax reform, is not encouraging in the long run. High oil prices on the world market are resulting in a revenue windfall for the state in the short term that provides sizeable budget surpluses. However, in the long term, production volumes from the North Slope oil reserves will continue to decline. It is hoped that the

[9] Some stranded gas is on federal and privately owned lands but fiscal terms for those leases would not be subject to this contract between the state and the applicant.

investment incentives included in the recently enacted petroleum profits tax system reverse this trend. The combination of lower crude oil production volumes coupled with increased liabilities will conspire to increase expenditures at a time when revenue from oil will decline. The state's budget surplus will likely slide into a deficit in three years as oil revenues decline due to reduced production and lower crude oil prices. The state is fortunate to have a $2.2 billion balance in the Constitutional Budget Reserve Fund and may someday have the opportunity to access the earnings of the $34 billion Alaska Permanent Fund. Figure 1 depicts the changes in Alaska's general fund unrestricted revenues from 2005-2050. As the graph illustrates, the fiscal surplus soon gives way to significant deficits.

Figure 1. Alaska Surplus/Deficit – No Gas Pipeline Scenario



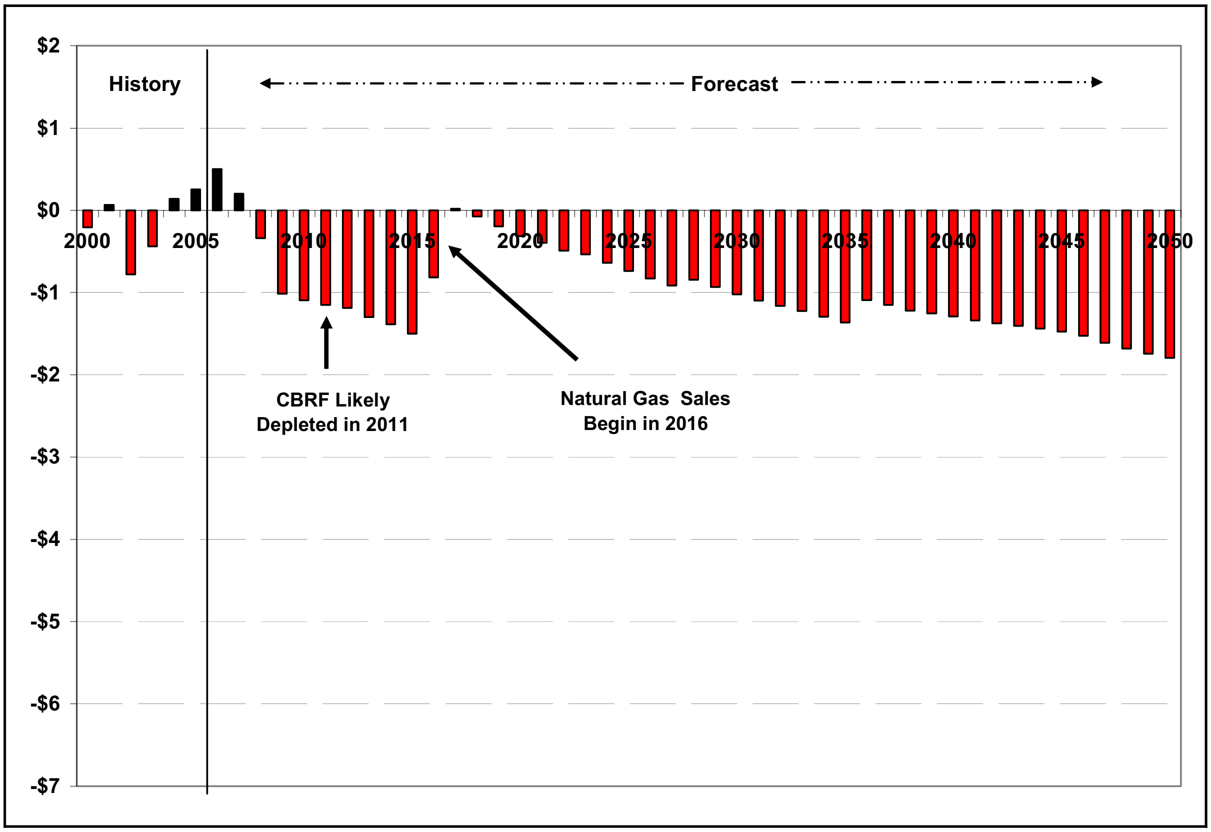
Source: ADOR model.

Note: Figure shows historical and projected general fund unrestricted revenues, FY 2000-2050, in billions of nominal dollars, at $33 per barrel price of ANS crude oil.

An examination of Figure 1 reveals that these data are just for the General Fund Unrestricted Revenues, oil production ends in 2030 and the Constitutional Budget Reserve [CBRF] will likely be depleted by 2011. The state's deficits get progressively worse each year and are greater than $6 billion per year during the last three years of the forecast period. It is assumed that the state takes no action to reduce the budget deficits other than withdrawing money from the CBRF. Other options might include reducing expenditures, implementing a state sales tax, implementing a state income tax, using money from the Permanent Fund, or a combination of these choices. Without implementing other options, the cumulative deficit is on the order of $150 billion.

Were the state to have natural gas development and a natural gas pipeline, the long run fiscal outlook would look different—although there would still be deficits (see Figure 2).

Figure 2. Alaska Surplus/Deficit – with Gas Pipeline Scenario



Source: ADOR model.

Note: Figure shows historical and projected general fund unrestricted revenues, FY 2000-2050, in billions of nominal dollars, at $33 per barrel of ANS crude oil and $5.50 per mmBtu of natural gas (Henry Hub).

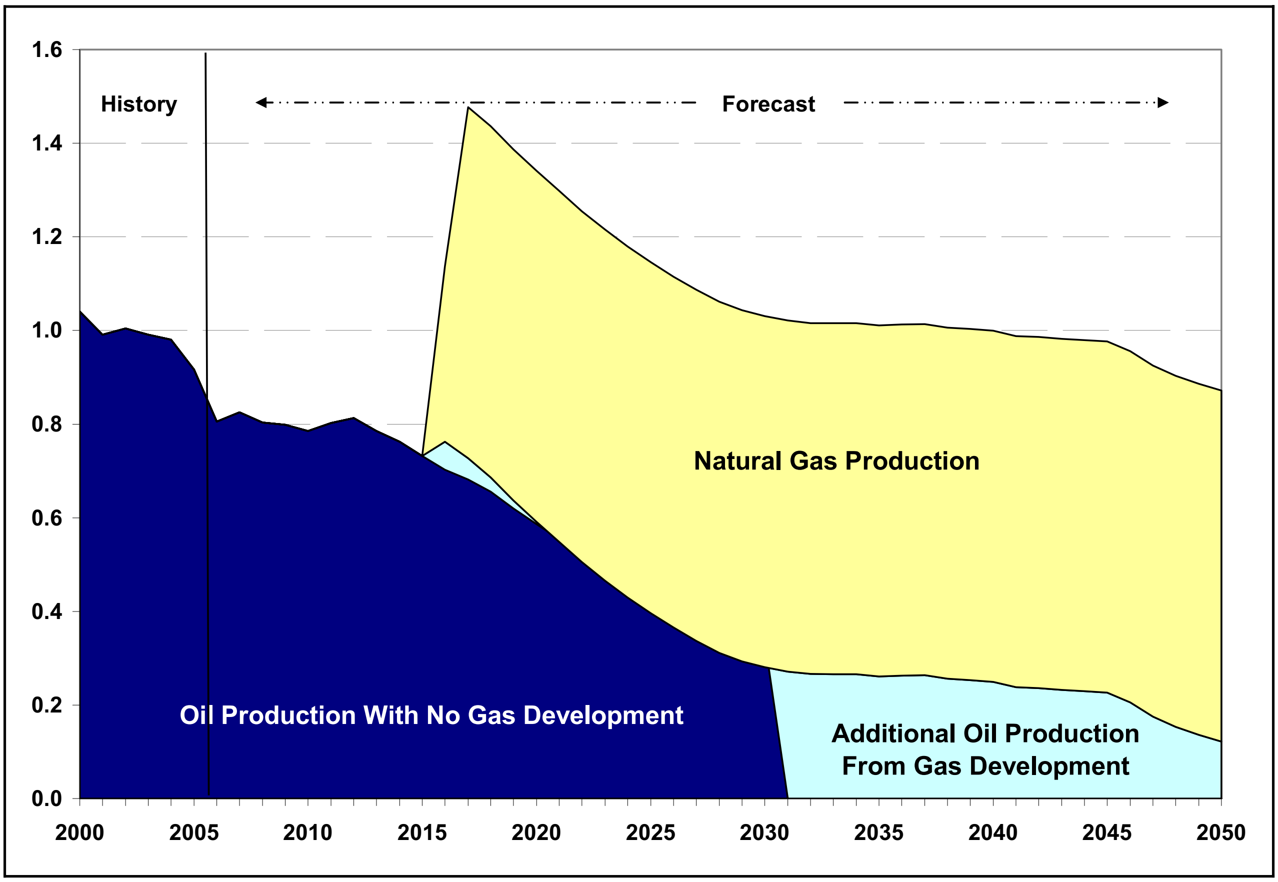
As examination of Figure 2 reveals that the CBRF is still depleted in 2011, but natural gas production begins in 2016. The deficits are smaller with a natural gas pipeline; however, the State of Alaska still runs a deficit for most years after 2008 with the deficits between $1 and $2 billion per year after 2030. Cumulative deficits are on the order of $44.5 billion and it is assumed the state takes no additional action to reduce the deficit. The outlook is based on the following: (1) the oil and gas production profile, (2) future oil and gas prices; (3) future government expenditures, (4) non-oil revenue and (5) the fiscal system in place. Each of these is now reviewed.

1.1.1 Future Oil and Gas Production

Without a gas line, it is expected that crude oil production will decline and end in 2030. With a gas line, crude oil production will extend beyond 2030 and be ongoing at the end of the forecast period. It is expected that natural gas production will begin in 2016, ramp up over the first year, and then reach a plateau of 4.5 billion cubic feet per day that will last for the forecast period. By having a gas line, an additional 1.575 billion barrels of oil are produced during the 44 year forecast period.

The crude oil production forecast for oil with no gas line is that contained in the *Spring 2006 Revenue Sources Book* (ADOR, 2006). Figure 3 presents this data in graphical form. In addition, Figure 3 also presents the production profile for natural gas, and the additional oil that is produced due to the gas line.

Figure 3. Historical and Projected Crude Oil and Natural Gas Production



Source: ADOR.

Note: Production volumes are expressed in millions of barrels of oil equivalent per day, FY 2000-2050.

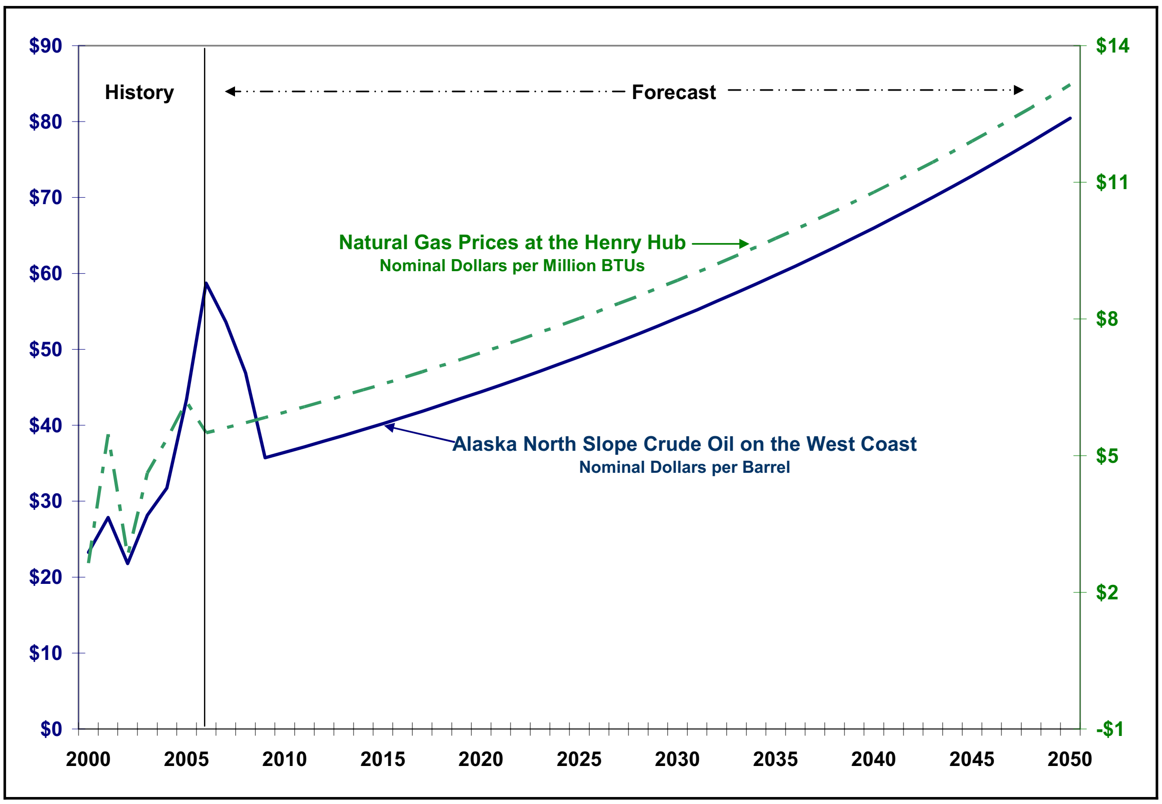
As can be seen from Figure 3, natural gas production is dramatic and accounts for the majority of hydrocarbons produced on the North Slope after 2030. Also, crude oil production is extended due to the association of crude oil and natural gas in the production process. With the development of a natural gas pipeline, Alaska will be transformed from an oil province to a natural gas province.

1.1.2 Future Energy Prices

For this analysis, the price for ANS West Coast crude oil is the Alaska Department of Revenue's (ADOR) price forecast for FY 2006, FY 2007 and FY 2008. Beginning in FY 2009, the price is $35.72 per barrel escalated at 2 percent per year. All these prices are in nominal dollars and this means crude prices reach $80 per barrel in 2050.

For this analysis, the price of natural gas at the Henry Hub is $5.50 per mmBtu beginning in FY 2006 and escalating at 2 percent per year. By 2050 the price of natural gas at the Henry Hub has returned to the $13 per mmBtu level. These prices are shown in Figure 4.

Figure 4. Historical and Projected Crude Oil and Natural Gas Prices



Source: ADOR model.

Note: Prices are expressed in nominal dollars by fiscal year.

A review of Figure 4 reveals that prices dip from their current high levels and then gradually return to higher levels—all in nominal dollars. The analysis in this document uses three sets of prices; what is shown here (Figure 4) are the mid-range prices.

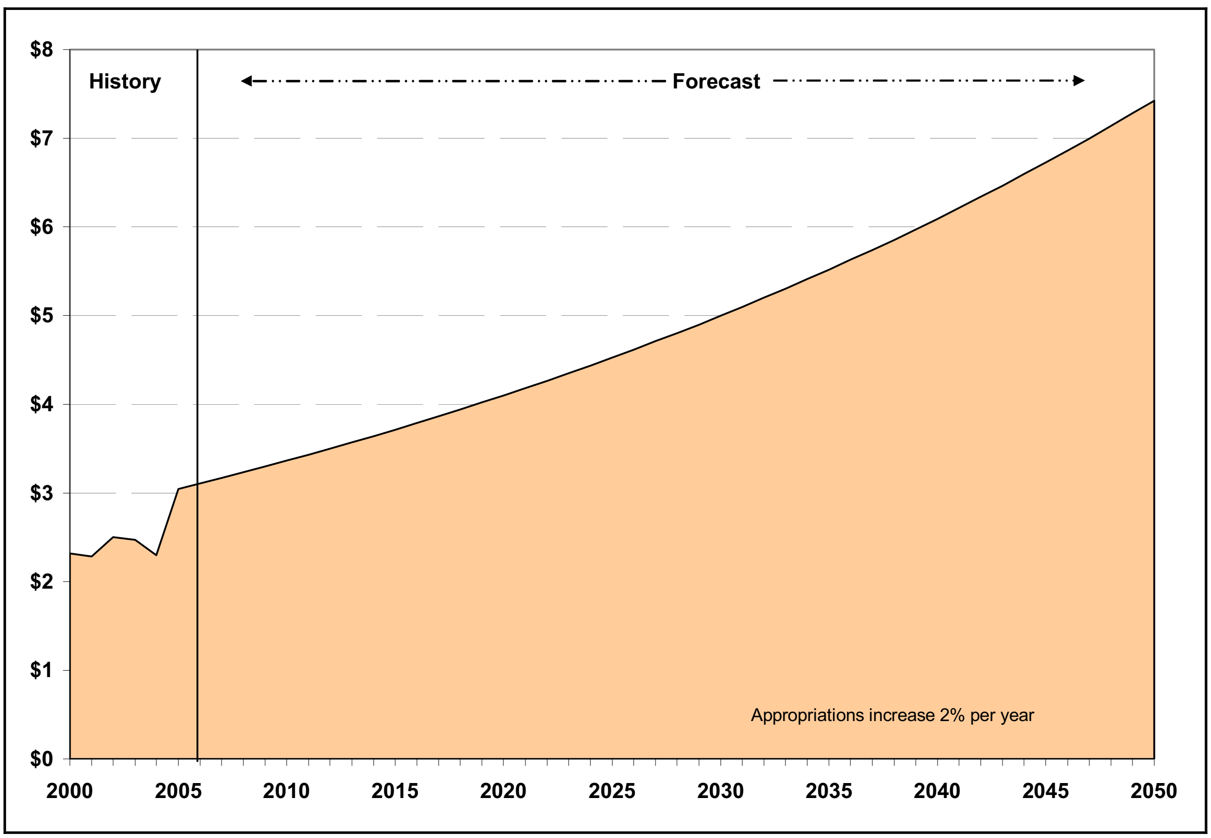
1.1.3 Future Alaska Government Appropriations

For this analysis, expenditures categorized as Unrestricted General Fund Appropriations are those that are examined. In FY 2005 the unrestricted general fund budget was $3.0 billion. It is assumed this budget increases at 2 percent per year—which probably underestimates the budget for future years. Reasons this likely understates the budget are the following:

- Alaska General Fund debt increased from $600 million to $1.5 billion in the last four years. This will cause increasing payments to repay the debt.
- Medicaid costs are increasing 13 percent per year.
- The unfunded liability for public employer pension plans, Alaska PERS and TRS, jumped $1 billion in the past year to $7 billion. The PERS and TRS plans are mature plans with the number of retirees and growth in the number of retirees exceeding the number of employees and growth in the number of employees. This will cause increased expenditures by the state to fund the pension system.
- General state government operating costs have been increasing at an annual rate of about 13 percent (higher petroleum prices are part of the reason).

Figure 5 presents the general fund appropriations in graphical form.

Figure 5. General Fund Appropriations



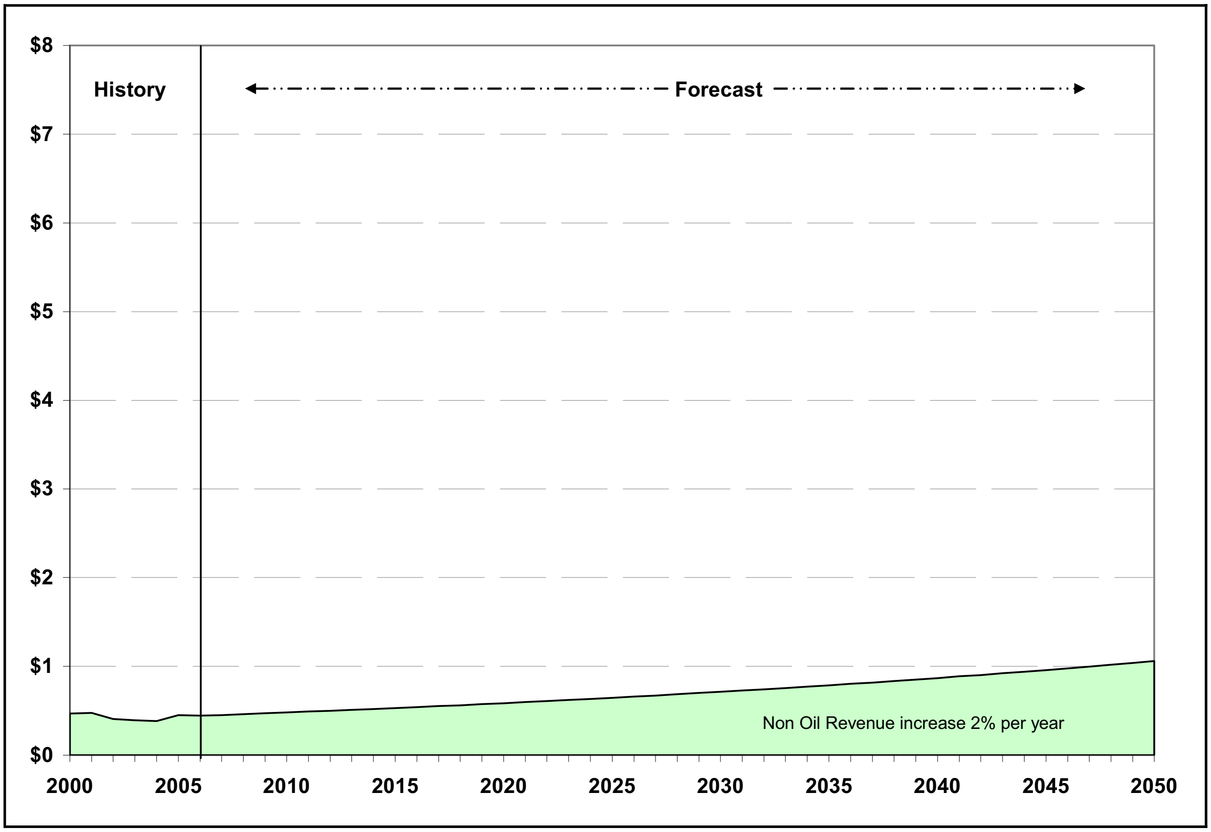
Source: ADOR model.

Note: Values are expressed in billions of nominal dollars by fiscal year.

1.1.4 Non-Oil Revenue

In FY 2005 non-oil revenues were about $449 million and the estimate for FY 2006 is $443 million (ADOR, 2006a). Thereafter it is assumed non-oil revenues will increase at a rate of 2 percent per year. Figure 6 presents the data in graphical form.

Figure 6. Non-Oil Alaska Revenues



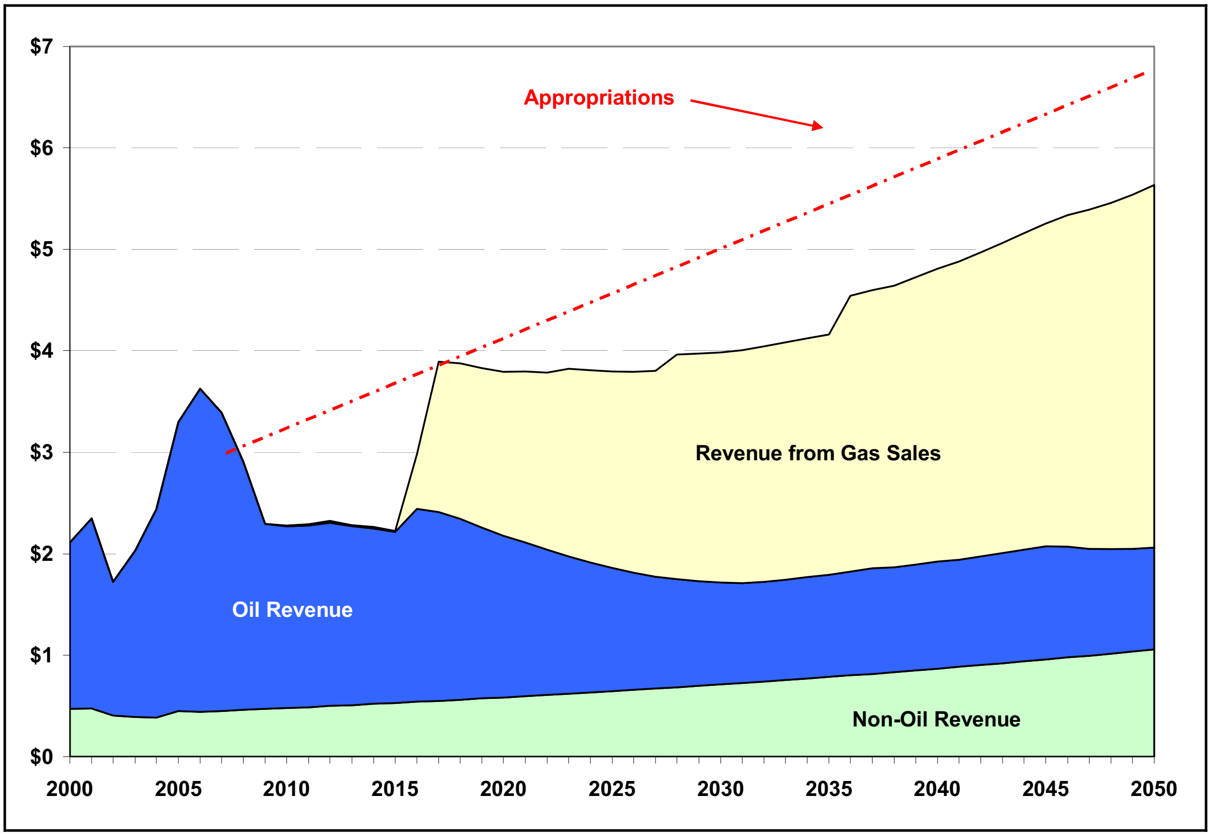
Source: ADOR model.

Note: Values are expressed in billions of nominal dollars by fiscal year.

Non-oil revenues include taxes on alcohol, cigarettes, fees for different services and investment income on certain investments that can be used for general fund unrestricted revenues. Note the scale on the axis—non-oil revenues are just above $1 billion in 2050 and are always less than revenues from oil—even though non-oil revenues grow 2 percent per year.

Combining all of the revenue sources (oil, gas, and non-oil), plotting them on a chart, with the General Fund Unrestricted Appropriations yields Figure 7.

Figure 7. Total Revenue under the 2005 Fiscal System



Source: ADOR model.

Notes:

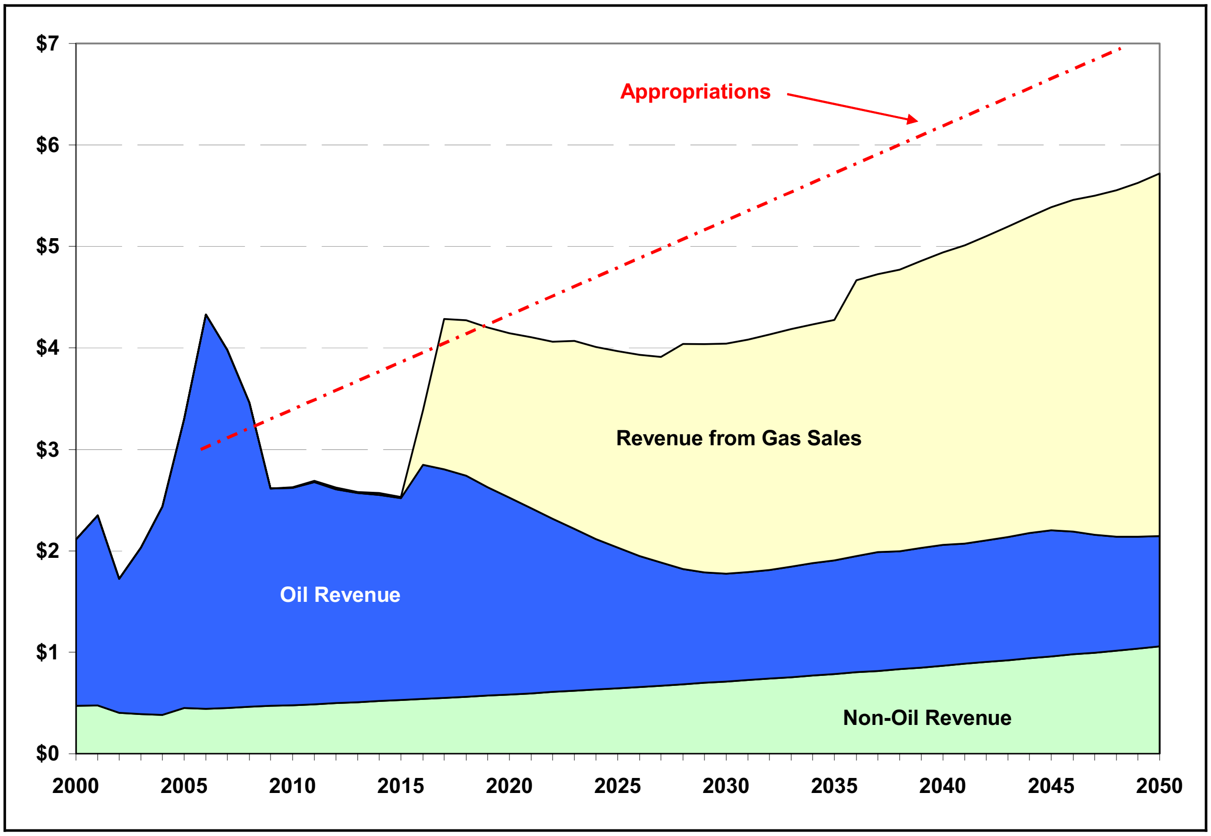
1. Revenues are expressed in billions of nominal dollars by fiscal year from 2000 to 2050.
2. Price assumptions: ANS oil price of $33 per barrel; natural gas price of $5.50 per mmBtu (Henry Hub).

An examination of Figure 7 reveals that non-oil revenues continually increase while revenues from oil decrease irregularly after 2010 primarily because crude oil production volumes decrease—even though prices increase 2 percent per year. When natural gas sales begin, revenues increase dramatically and continue to increase because prices increase 2 percent per year. For most years, total revenue is less than the appropriations with the CBRF making up the difference until 2011. Again, it is assumed that the state takes no action to reduce the deficit.

1.1.5 Fiscal Systems

All of the analysis used in the previous sections assumed the fiscal terms that were in effect during 2005—including the petroleum production tax that used the Economic Limit Factor or ELF. In May 2006 the Alaska legislature is evaluating new laws instituting a new production tax system, the PPT. The analysis now re-constructs all revenues, including oil revenues that incorporate the PPT. Figure 8 presents all revenues assuming the natural gas sales and the new PPT.

Figure 8. Total Revenue with the PPT



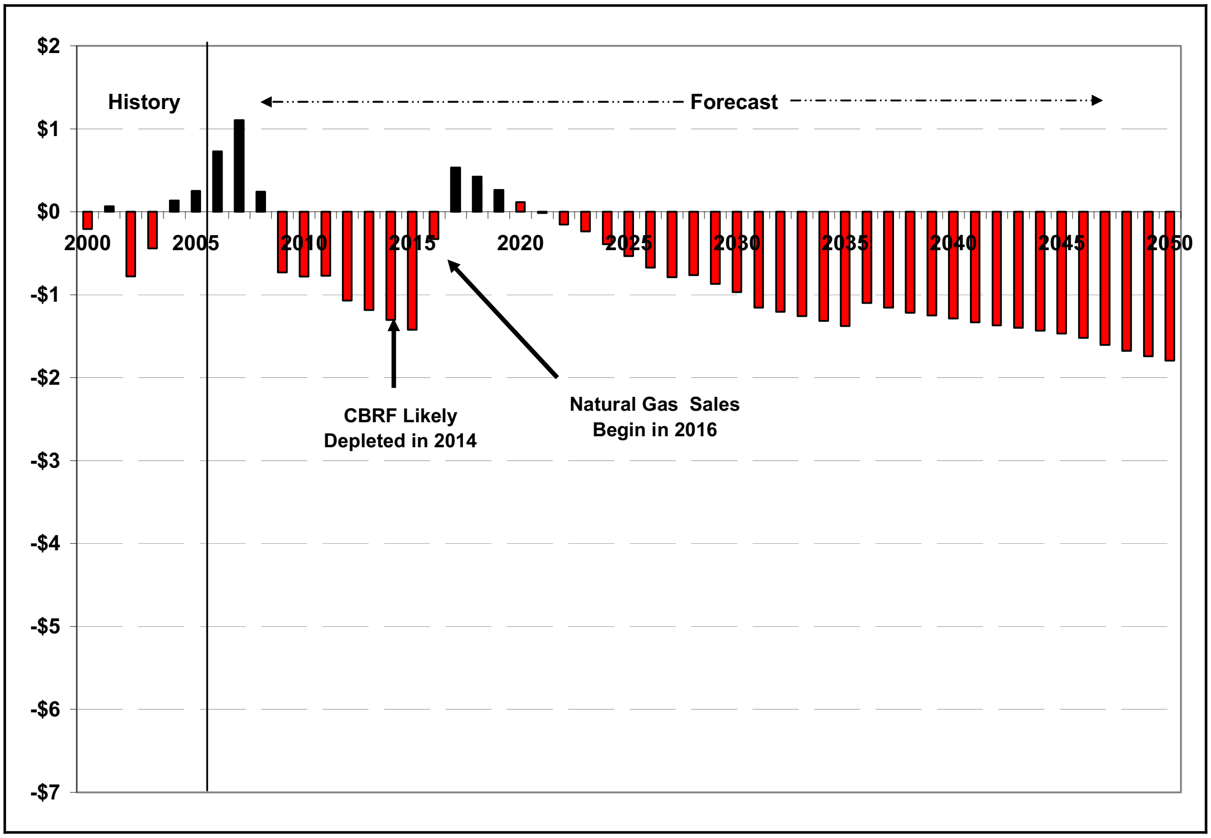
Source: ADOR Model.

Notes:

1. Revenues are expressed in billions of nominal dollars by fiscal year from 2000 to 2050.
2. Price assumptions: ANS oil price of $33 per barrel; natural gas price of $5.50 per mmBtu (Henry Hub).

While Figure 7 and Figure 8 appear similar, there is a surplus for four years with the PPT system that begins in 2017—versus only one year of surplus under the system using the ELF. As before, it is assumed the state takes no action to reduce the deficits. To pinpoint the deficits, the deficit / surplus chart is presented for each year during the forecast period in Figure 9.

Figure 9. Alaska Surplus/Deficit – with Gas Pipeline under the PPT

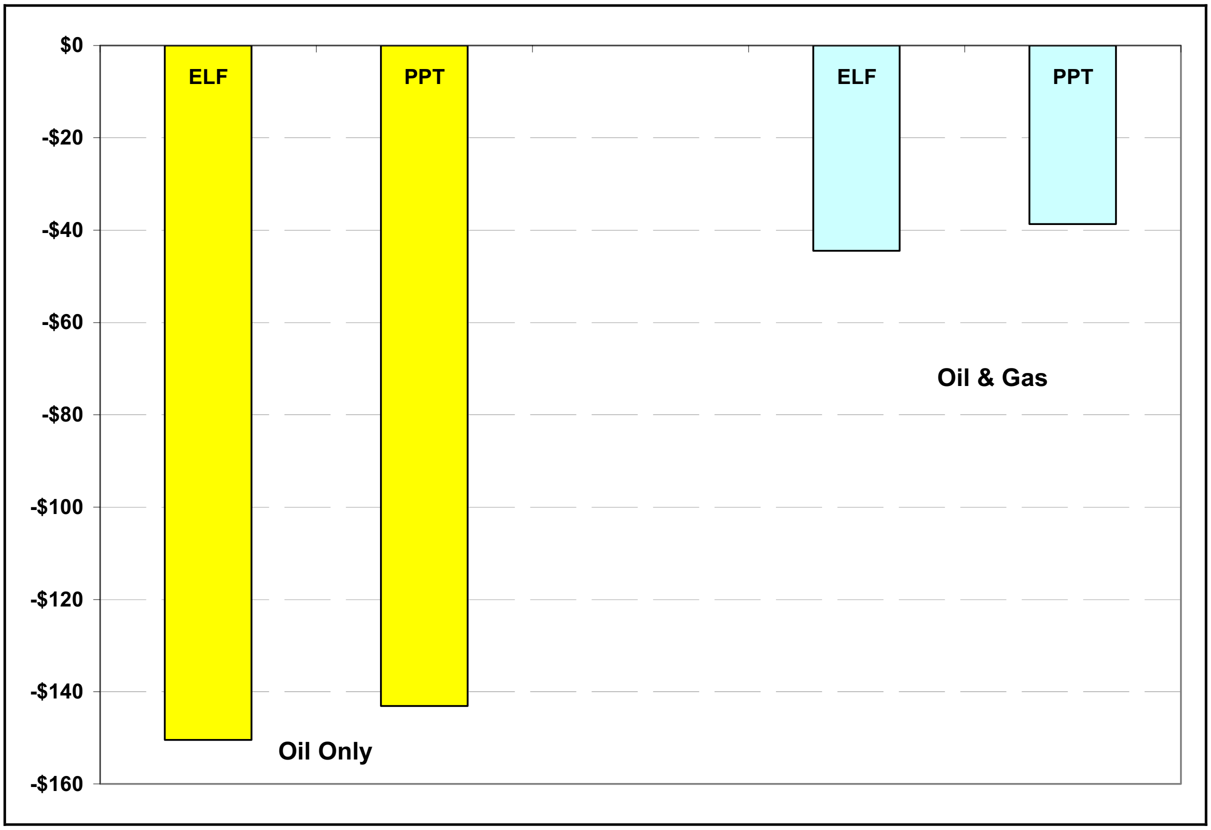


Source: ADOR model.

Note: Figure shows historical and projected general fund unrestricted revenues, FY 2000-2050, in billions of nominal dollars, at $33 per barrel of ANS crude oil and $5.50 per mmBtu of natural gas (Henry Hub).

Under the PPT, and with natural gas sales, the deficit never reaches $2 billion a year. The cumulative deficit is on the order of $37.2 billion. To get a better comparison of the surpluses and deficits under the two fiscal systems, the cumulative deficits with and with-out natural gas sales are presented in Figure 10.

Figure 10. Cumulative Deficits Under Two Different Fiscal Systems



Source: ADOR.

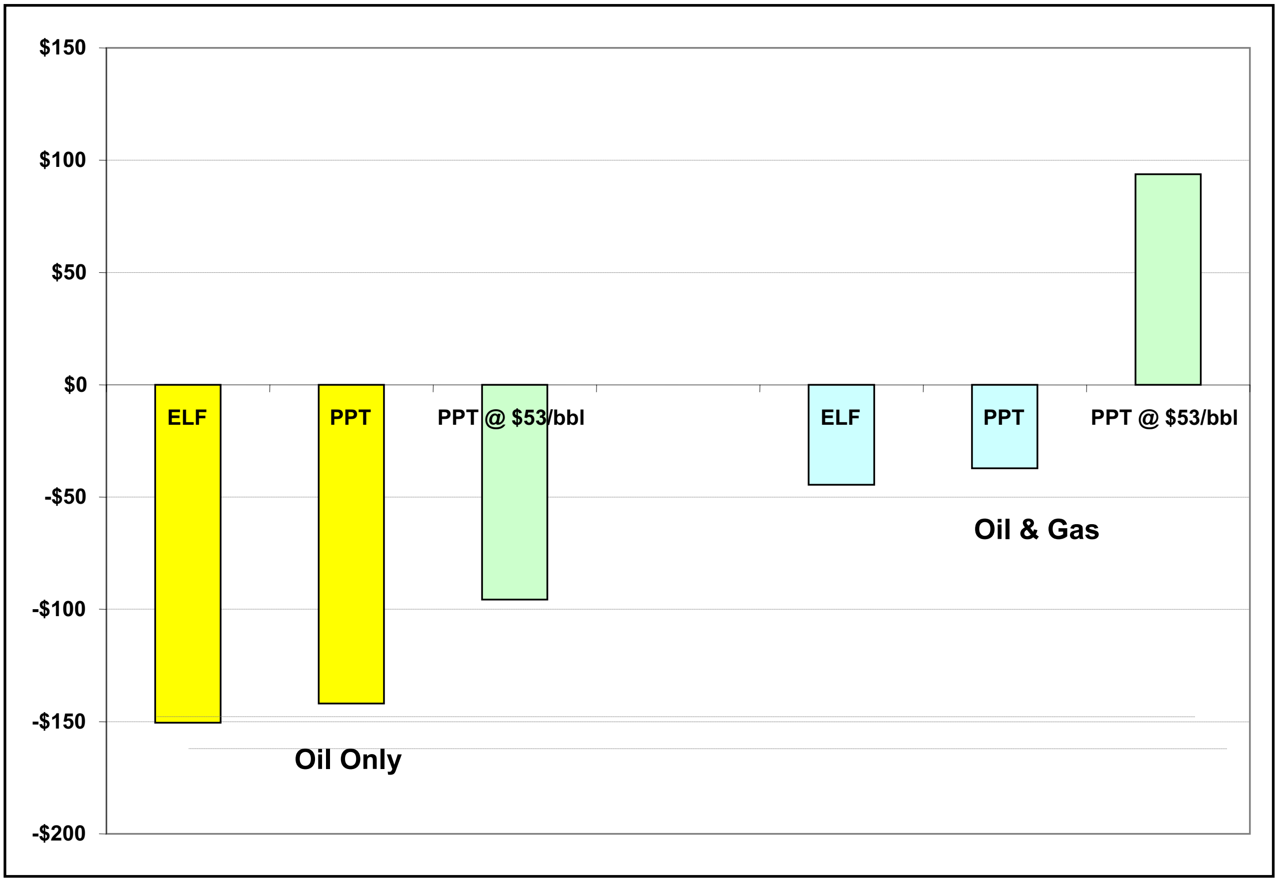
Notes:

1. Values are in billions of nominal dollars.
2. Values are total cumulative amounts for FY 2006 to FY 2050.
3. Price assumptions: ANS crude oil price of $33 per barrel; natural gas price of $5.50 per mmBtu (Henry Hub).

If natural gas sales do NOT occur, cumulative state budget deficits will be on the order of $150 billion during the forecast period with the ELF severance tax system, and $142 billion with the PPT severance tax system. If gas sales do occur, cumulative budget deficits will be on the order of $44.5 billion with the ELF severance tax system, and $37.2 billion with the PPT severance tax system. In both cases the PPT provides the State of Alaska with more revenue than the production tax system using ELF—but the new PPT system does not prevent budget deficits between now and 2016. Keep in mind these use the prices of $5.50 per mmBtu for natural gas and $33 per barrel of oil.

Should prices be $8.50 per mmBtu for natural gas, and $53 per barrel of oil, the outlook would be slightly different [remember prices increase 2 percent per year]. In the case where there was no gas line, the cumulative deficit would total about $95.6 billion. With a gas line, the state would run a surplus in excess of $93 billion between 2006 and 2050. See Figure 11.

Figure 11. Cumulative Deficits under Two Different Fiscal Systems



Source: ADOR Model.

Notes:

1. Values are expressed in billions of nominal dollars.
2. Values are total cumulative amounts for the period FY 2006 to FY 2050.
3. Price assumptions: i) ANS crude oil price of $33 per barrel; natural gas price of $5.50 per mmBtu (Henry Hub); ii) Additional scenario at $53 per barrel of ANS crude oil; natural gas price of $8.50 per mmBtu (Henry Hub).

In summary, this long run outlook presents a simplified view of how the state's finances might unfold during the next 45 years. It assumes a certain level of increase in state appropriations which seems reasonable given the large liabilities the state faces. At the same time it assumes declining oil production coupled with crude oil prices that decline and then increase. Combining the increasing state appropriations with declining revenue implies long run fiscal deficits. The outlook also assumes the state takes no action to balance the budget. Finally, only in the case where oil and gas prices are "higher" does the state run a cumulative surplus—and this only occurs when there is a gas line.

1.2 Alaska North Slope Natural Gas Resources

Information on the amount of natural gas resources and reserves in the ANS, historical and projected prices of natural gas, and the impacts of gas production on oil production in ANS fields are all important in the analysis of the contract and in the evaluation of an Alaska gas pipeline project. This information is provided in the following sections.

1.2.1 Volume of ANS Natural Gas Resources and Reserves

The recoverable known ANS gas resources are estimated to total approximately 35 trillion cubic feet (tcf), as shown in Table 1. To put this amount into perspective, the U.S. consumed about 22 tcf of natural gas in 2004 (EIA, 2005). The Prudhoe Bay oil field contains about 65 percent of the known resources, and the gas condensate field at Point Thomson contains about 23 percent of the known resources.

ANS gas production in 2000 was approximately 3.2 tcf of associated natural gas (including CO_2), or 8.7 billion cubic feet per day (bcf/d). Ninety-three percent of this amount was re-injected into the oil producing reservoirs. The remaining 297 bcf was consumed locally to fuel oil field equipment, operations, and pipelines (including pump stations 1 to 4 of the Trans Alaska Pipeline System (TAPS). The annual ANS gas consumption is approximately equal to the annual amount of gas produced in the Cook Inlet (ADNR, 2004).

Table 1. Estimated Remaining Recoverable Known Hydrocarbon Gas Resources in North Slope, Alaska

Known Reserves Unit or Area	Gas Reserves (bcf)
Prudhoe Bay Field	23,000
Point Thomson	8,000
Duck Island Unit	843
Kuparuk River Unit	1,150
Northstar	450
Colville River Unit	400
Barrow-Walakpa	34
Milne Point Unit	14
Greater Point McIntyre	1,526
Total North Slope Alaska	35,417

Source: ADNR, Division of Oil and Gas 2004 Annual Report.

Notes: Remaining recoverable resources are gas that are economic and technologically feasible to produce and are expected to produce revenue in the foreseeable future.

Additional natural gas accumulations have also been encountered in exploration wells drilled in the Brooks Range foothills and some offshore locations; however, in the absence of a market for natural gas, these accumulations have not been delineated and are not included in the reserve estimates. Based on geologic conditions, it is generally believed that significant undiscovered gas resources are very likely to exist in unexplored areas.

The United States Geological Survey (USGS) has estimated the volume of technically recoverable conventional oil and natural gas resources in the ANS that have not yet been discovered. Their petroleum resource assessments suggest that significant resources of undiscovered natural gas exist in the National Petroleum Reserve-Alaska (NPR-A), Arctic

National Wildlife Refuge (ANWR), the Central North Slope (the area between the NPR-A and ANWR), and in the state waters adjacent to all three areas.

The USGS resource assessment indicates:

- The NPR-A and adjacent state waters are estimated to contain 40 (95 percent probability) to 85 (5 percent probability) tcf of technically recoverable, non-associated gas, with a mean value of 61.4 tcf (Bird and Houseknecht, 2002). The NPR-A is also estimated to contain 11.7 tcf (mean estimate) of associated gas (Schuenemeyer, 2003);
- The mean value of estimates for the ANWR 1002 area and adjacent state waters indicate the area contains 3.8 tcf of technically recoverable, non-associated gas, and 4.8 tcf of associated gas resources; and
- The central part of the ANS and adjacent state waters are estimated to hold 37.5 tcf (mean value) of undiscovered, technically recoverable natural gas reserves (USGS, 2005).

The mean value of estimates of the total undiscovered natural gas resource in the ANS is 119 tcf. Combined with known resources of slightly more than 35 tcf, the ANS region is estimated to hold about 155 tcf. To put this into context, the U.S. consumed 22 tcf of natural gas in 2004 (EIA, 2005c).

1.2.2 Impacts of Gas Production on Oil Production

There is a clear and demonstrable connection between the development of the state's gas and oil resources. In practice, the discovery of oil also includes the discovery of gas. A significant amount of gas is produced with each barrel of ANS oil. It logically follows that a plan to monetize the state's gas should include incentives related to taxes on both gas and oil.

The leaseholders of the ANS oil and gas resources, and the state, have a large incentive to maximize the value of both oil and gas resources. The challenge is to optimize current and future production to maintain a consistent revenue source and maximize ultimate recovery of oil and gas from the reservoir. At Prudhoe Bay, gas plays an important role in assisting oil production. Injecting gas back into the reservoir helps oil production by maintaining reservoir pressure and by gas cycling: the vaporizing and recovering of oil components as the gas cycles through the reservoir. Gas can also be re-injected alternating with water as part of technologically sophisticated process known as enhanced oil recovery, in which a cocktail of enriched gas condenses into heavier oil, allowing water to wash the lighter product into the wellbore. These gas roles- pressure maintenance, cycling, EOR - are used to recover oil in the reservoir that would otherwise be left in place. Gas is also used to fuel field facilities, to generate power for oil field use, and to fuel some TAPS pump stations.

Large-scale gas production and sales would affect oil recovery because as gas is taken out of the reservoir, reservoir pressure falls and it becomes harder to recover the remaining oil. The owners will certainly explore techniques to offset the effects of major gas sales on oil recovery. Currently, oil losses due to a gas sale from Prudhoe Bay are estimated to be approximately 300 million barrels through 2030. Reduced oil production also is likely to affect the TAPS tariff since lower oil flows will mean higher transportation charges for the oil that remains, To maximize the cumulative hydrocarbon production (oil and gas), oil production should be continued as far into the future as possible. Revenue from gas sales will extend PBU field life, and the life of TAPS, by sharing some of the joint costs of the oil and gas production process. However, to maximize revenue generation, the sale of gas needs to begin as soon as possible.

The Prudhoe Bay oil pool is currently limited to 2.7 bcf/d that can be used or removed from the field (off-take) according to rules adopted by the Alaska Oil and Gas Conservation Commission (AOGCC) in 1977. AOGCC will review the proposed plan of gas production from the ANS gas fields and in approving the plan and setting a maximum gas off take rate will review and attempt to minimize losses in oil production (AOGCC, 2005).

1.2.3 Cost Sharing and Economically Recoverable Oil Resources

The period of time over which a field can economically produce oil and gas resources is sensitive to prices, tax and regulatory burdens, operating costs, and transportation costs. Spreading the costs of gas handling between the oil and gas production operations would increase the overall productivity of oil and gas fields in the North Slope. The Prudhoe Bay Unit owners have spent nearly $2 billion to increase gas-handling capacity over the period 1987 to 1992 (BP, 1992). The production facilities in Prudhoe Bay include a central gas processing facility and a central compressor (injection facility), among others (PRA, 2004). Gas sales are anticipated to help pay operating costs and extend the life of oil production. Later in the field life of Prudhoe Bay, oil production is likely to become a by-product of gas production.

Gas sales and higher industry profits could also induce development and production of more marginal fields in the ANS and the use of existing oil infrastructure, leading to greater economically recoverable oil reserves in the ANS.

1.3 History of Attempts to Build Pipeline

There have been three and a half decades of private sector interest and federal policy initiatives attempting to bring ANS gas to market. This section provides a historic overview of the interest and attempts to mobilize support to build a gas pipeline. These attempts begin with the Alaska Natural Gas Transportation Act.

1.3.1 Alaska Natural Gas Transportation Act (ANGTA)

The benefits of bringing ANS gas to markets have been discussed since the 1970s, and a series of early pipeline projects were proposed by the oil and gas industry (EIA, 2005a; Office of the Governor, 2005). In 1974, Arctic Gas, a consortium of U.S. and Canadian natural gas pipeline and distribution companies, proposed a route through ANWR and then through Canada to the lower 48 states. Another option proposed that year involved piping the gas to various Southcentral Alaska tidewater locations, converting it to liquefied natural gas (LNG), and loading it onto LNG tankers for export. In 1976, another consortium of U.S. and Canadian companies, led by the Northwest Alaskan Pipeline Company and Foothills Pipe Lines, Ltd., proposed constructing a gas pipeline along the southern AlCan Highway route.

These early proposals were accompanied by federal policy initiatives in support of a pipeline project. The Trans-Alaska Pipeline Authorization Act of 1973, 43 U.S.C. 1651, determined that the early development and delivery of ANS oil and gas to domestic markets is in the national interest because of growing domestic shortages and increasing dependence upon insecure foreign sources. The 1973 Act directed the U.S. President to enter into negotiations with Canada with respect to the possibility of an overland oil and gas pipeline from Alaska.

In 1975, the Federal Power Commission (FPC), the predecessor to the FERC, ordered a comparative hearing to select among the three projects. In 1976, as the hearing was underway, Congress passed the Alaska Natural Gas Transportation Act (ANGTA) to expedite and elevate the normal FPC administrative and court appeal procedures required for the necessary government authorizations of an Alaska gas transportation system (Pub. L. 94-586, 90 Stat 2903 (1976)). The ANGTA established a framework for presidential selection of the best delivery system after comparative hearings before the FPC.

Following FPC recommendation and comment from numerous federal agencies, the President was authorized to select the entity and the route to build an Alaska Natural Gas Transportation System (ANGTS) pipeline (Id. at Sec.7(a)(2)(B)).

In September 1977, President Carter in his Decision and Report to Congress on the Alaska Natural Gas Transportation System (Decision) selected what is now known as the Alaska Highway route and Alcan Pipeline Company, a subsidiary of Northwest Alaskan Pipeline Company, to build the Alaskan segment of the project.[1] Foothills Pipe Lines, Ltd., was to build the Canadian portion of the ANGTS, and the Northern Border Pipeline Company and Pacific Gas Transmission were to construct the lower 48 portions. Today, TransCanada is the successor in interest to Alcan Pipeline Company (later renamed Northwest Alaskan Pipeline Company) and Foothills Pipe Lines, Ltd. is a wholly-owned subsidiary of TransCanada.

As required by the ANGTA, President Carter explained the rationale of his decision and imposed multiple conditions on the project. Among these were requirements that the pipeline be privately financed and a prohibition barring ANS producers and their affiliates from owning any interest in the pipeline, although they were permitted to guarantee project debt:

> "The aforesaid producers of Alaska gas may not be equity members of the sponsoring consortium, have any voting power in the project, have any role in the management or operations of the project, have any continuing financial obligation in relation to debt guarantees associated with initial project financing after the project is completed and the tariff is put in effect, or impose conditions on the guarantees of project debt permitted above which may give rise to competitive abuse, including power to veto pro-competitive policies." (Executive Office of the President – Energy Policy and Planning, 1977.)

Thus, President Carter envisioned an independent pipeline.

The Canadian government proceeded down a parallel track that also resulted in the selection of Foothills and related companies to construct and operate the Canadian portion of the project. The U.S. and Canadian Governments entered into both a Transit Treaty ("Transit Pipelines Treaty", January 28, 1977) providing for nondiscriminatory treatment of a pipeline transiting Canada and an Agreement in Principle with Canada that mirrored the President's

Decision and the conditions it imposed ("Agreement between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline, September 20, 1977). The agreement contemplated that initial operation of the pipeline was to start on January 1, 1983, delivering 2 bcf/d from the ANS along the AlCan Highway route (EIA, 2005a).

Despite elaborate efforts both to complete the regulatory process and to develop a financing plan, the project was suspended in May 1982.

As the project sponsors and government agencies worked on the project during this five-year period, they found that several conditions imposed by the Decision were unworkable. As authorized by the ANGTA, President Reagan submitted eight "Waivers of Law" to Congress and Congress enacted these by Joint Resolution on December 15, 1981. One of these waived the prohibition of producer participation and substituted a requirement that FERC, after advice from the Attorney General, make a determination that the agreement would not create antitrust problems (S. Rep. No. 97-272, at 31 (1981)). As the Administration explained at the time, a "more thorough analysis of the antitrust issues" revealed that "sufficient antitrust protection" could be achieved by addressing "access and expansion" issues at the time of issuance of the final FERC certificate. The repeal of the ban on producer ownership constituted a recognition that the ANS producers could not be forced to loan money to a project in which they had no say and that the ANGTS could not succeed without their participation and financial strength.

Despite these policy initiatives, each of the pipeline and gas marketing proposals failed in the face of numerous challenges, the most notable being the extremely low gas prices in the U.S. market that followed the deregulation of U.S. natural gas supply and development of lower-cost resources both in the lower 48 states and Canada (EIA, 2005a). The Natural Gas Policy Act (NGPA) of 1978, 15 U.S.C. 717, ended federal control over the wellhead price of "new" gas as of January 1, 1985, but kept in place wellhead price controls for older vintages of gas. Prices at the producing wells became completely deregulated with passage of the Natural Gas Wellhead Decontrol Act of 1989, 15 U.S.C. 3301 (EIA, 2005b). As of January 1, 1993, all remaining price regulations were eliminated, allowing the market to determine completely the price of natural gas at the wellhead.[10]

1.3.2 Projects under Other Federal Statutes

A different plan gained momentum after the ANGTS did not succeed. The Yukon Pacific project, described in a petition to FERC in 1987, proposed bringing ANS gas to market by means of a LNG project. The project proposed constructing a natural gas pipeline from the ANS to tidewater at or near Valdez. The gas would be liquefied in Valdez and "exported exclusively into foreign commerce and (the gas) will not reach markets in the State of Hawaii or the lower 48 states" (Declaratory Order, p. 2. 39 FERC 61, 216.). Through a 1989 Department of Energy order, Yukon Pacific was authorized to export gas for sale to Japan, South Korea, and Taiwan for a period of 25 years, and in 1995, FERC authorized the

[10] Additional significant developments in the gas market included the encouragement of interstate pipeline companies to be "open access" carriers of natural gas bought directly by users from producers (1985 – FERC Order No. 436) and the requirement of interstate pipeline companies to "unbundle," or offer separately, their gas sales, transportation and storage services (1992 – FERC Order No. 636).

location, construction, and operation of a LNG facility explicitly for the export of gas to Japan, the Republic of Korea, and Taiwan.

Despite years of effort, the Yukon Pacific project did not go forward. Reportedly, the Alaska Gasline Port Authority (AGPA) Project has acquired the permits and authorizations for Yukon Pacific's Asia export project.

The removal of price controls resulted in changes that had the intended effect on both producers and consumers (Ridlehoover and Pulliam, 2002). As more gas was found and offered to market, gas prices fell sharply in the mid-1980s and stayed low through the 1990s, although periodic episodes of cold weather, hurricanes, and other short-lived factors generated a few price "spikes." The low prices prompted steady growth in gas consumption, aided by its reputation as a clean fuel for industrial uses and electricity generation (Ridlehoover and Pulliam, 2002). From 1986 to 2000, U.S. annual natural gas consumption grew from 16.2 tcf to a high of 23.3 tcf (EIA, 2005c).

But low prices also provided weak incentives for producers to find new reserves, and at times in the 1990s, they began withdrawing resources not only from ongoing exploration but also from development of existing fields (Ridlehoover and Pulliam, 2002). In 2000, the "quiet" market conditions of the 1990s abruptly awakened as prices began a steady climb early in the year. Concern about the increasing price was accompanied by questions regarding the adequacy of natural gas supplies for the lower 48 market (EIA, 2005c). Imports, predominantly from Canada, met 40 percent of the increased demand in the U.S. market. Based on an assessment from Canada's National Energy Board (NEB), however, future production from Canada was unlikely to support a continued increase in U.S. imports (EIA, 2005c).

By late 2000, the market had no reserve capacity, and the tight supply created a trend toward higher and more volatile prices (Elliott, 2004). These market conditions led to a reevaluation of the feasibility of developing stranded Alaska gas reserves (EIA, 2005a). BP, CP and EM (the three major oil producers that own 90 percent of the known ANS natural gas reserves) formed the North American Natural Gas Pipeline Group to investigate the potential of developing a gas pipeline. The results of their $125 million analysis, released in 2002, indicated that the project was not commercially viable at that time, and that the State of Alaska and federal governments in the U.S. and Canada would need to play a role in reducing project costs and associated risks (EIA, 2005a).

1.3.3 Alaska Natural Gas Pipeline Act (ANGPA)

Interest in the development of ANS natural gas resources was renewed in the early 2000s, as the Bush administration touted energy independence and infrastructure development. President Bush introduced a comprehensive national energy act and urged Congress to remove the hurdles to building pipelines and electric transmission facilities. As the energy legislation moved through Congress, a consensus package of provisions to aid the development of an Alaska gas pipeline was developed, resulting in the Alaska Natural Gas Pipeline Act of 2004 (ANGPA). Representatives of the state, major ANS producers, TransCanada, the lower 48 pipeline industry, FERC, and independent explorers such as Anadarko participated in developing the consensus provisions. A small set of technical amendments was passed a few months later, and Congress enacted certain tax related provisions that also assisted the project.

The purpose of the ANGPA is to clarify and expedite the process of developing a new Alaska gas pipeline. The provisions established by the ANGPA describe FERC's role in the natural gas pipeline development. According to the ANGPA, FERC can accept and process an application for a new project under the act. FERC is responsible for the environmental impact assessment process, and the process is expedited by limits placed on development of the EIS, processing the application for the certificate of public convenience and necessity, and judicial review. Because the Alaska gas pipeline is likely to be the only option to market ANS resources, Congress gave FERC the power to order an expansion of the pipeline to satisfy competitive concerns. This provision is the first time FERC has been given the power to order an expansion of any interstate pipeline (see Section 1.3.3.6).

The ANGPA does not affect any decision, certificate, permit, right-of-way, lease or other authorization granted under ANGTA or any Presidential finding or waiver under that statute. It does permit amendment of the terms and conditions of such actions "to meet current project requirements," provided that the amendment would not compel any change in the "basic nature and general route" of the ANGTS or otherwise "prevent or impair significantly its expeditious construction." The secretary of energy is required to submit updated environmental data and reviews as the secretary determines are necessary (ANGPA, Section 110).

The major provisions of ANGPA are summarized in Sections 1.3.3.1 through 1.3.3.11. Topics discussed include: expedited approval process, prohibition of certain pipeline routes, environmental reviews, federal coordinator, expansion, open season requirements, in-Alaska service, study of alternative means of construction, and loan guarantees.[11]

1.3.3.1 FERC Authorized to Proceed Non-ANGTA Applications (Section 103(a))

Notwithstanding the ANGTA, FERC is authorized to consider and act upon an application for the issuance of a certificate of public convenience and necessity for a new project.

1.3.3.2 Expedited Approval Process (Section 103(c))

FERC is given a total of 20 months from the submission of a complete application to prepare the environmental impact statement (EIS) and issue a certificate. Specifically, not later than 60 days after the date of issuance of the final EIS, FERC shall issue a final order granting or denying any application for a certificate of public convenience and necessity for the project under the Natural Gas Act (15 U.S.C. 717f(e)). FERC regulations are discussed in Section 8 of this report.

1.3.3.3 Prohibition of an Over-the-Top Route (Section 103(d))

No license, permit, lease, right-of-way, authorization, or other approval required under federal law for the construction of any pipeline to transport natural gas from land within the

[11] As of June 15, 2005, the full text of the ANGPA can be found through the Federal Energy Regulatory Commission Internet Site at http://www.ferc.gov/industries/gas/indus-act/angtp/act.htm#act.

Prudhoe Bay oil and gas lease area may be granted for any pipeline that follows a route that (1) traverses navigable waters or the adjacent shoreline of the Beaufort Sea; and (2) enters Canada at any point north of 68 degrees north latitude.

1.3.3.4 FERC Required to Adopt Regulations for an Open Season (Section 103(e))

Historically, FERC has dealt with open season issues on a case by case basis. Section 103(e) requires FERC to promptly adopt a set of regulations governing the open season on an Alaska gas pipeline. The regulations do not apply to capacity made available as the result of a FERC-ordered expansion.

1.3.3.5 Environmental Reviews (Section 104)

The issuance of a certificate of public convenience and necessity authorizing the construction and operation of any Alaska natural gas transportation project must be treated as a major federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act of 1969 (NEPA). ANGPA designates FERC as the lead agency for the NEPA process. FERC shall prepare a single EIS, which shall consolidate the environmental reviews of all federal agencies considering any aspect of the Alaska natural gas transportation project. FERC shall (1) issue a draft EIS not later than one year after it determines that the application for an Alaska natural gas transportation project is complete; and (2) issue a final EIS not later than 180 days after the date of issuance of the draft EIS, unless FERC for good cause determines that additional time is needed.

1.3.3.6 FERC Given Expansion Rights for the First Time (Section 105)

Historically, FERC has lacked the power to order expansion of a pipeline to accommodate new customers. Because of concerns expressed by the state and independent explorers, ANGPA gives the FERC the power to order expansion of an Alaska gas pipeline after it is built. These powers are carefully spelled out and contain conditions and special procedures that must be satisfied.

1.3.3.7 Special In-State Provisions (Sections 103, 106, and 108)

Congress adopted a set of provisions that specifically address State of Alaska concerns. First, Congress required the successful applicant to study in-state needs and tie-in points for in-state access (Section 103 (g)). Second, ANGPA requires the FERC to provide “reasonable access” to the pipeline for the transportation of royalty gas of the state “for the purpose of meeting local consumption needs within the state” (Section 103(h)). Third, ANGPA makes clear that the justification of the FERC does not extend to a spur line that delivers gas to consumers within Alaska; that justification is being reserved for the Regulatory Commission of Alaska (Section 108 (a)). Fourth, ANGPA makes clear that the state shall have primary surveillance and monitoring responsibility in areas where an Alaska gas pipeline would cross state lands (Section 106(e)).

1.3.3.8 Federal Coordinator (Section 106)

The Office of the Federal Coordinator for Alaska Natural Gas Transportation Projects is established as an independent office in the executive branch to (1) coordinate the expeditious discharge of all activities by federal agencies with respect to an Alaska natural gas transportation project; and (2) ensure the compliance of federal agencies with the provisions of ANGPA.

1.3.3.9 Study of Alternative Means of Construction (Section 109)

If no application for the issuance of a certificate or amended certificate of public convenience and necessity authorizing the construction and operation of an Alaska natural gas transportation project has been filed with FERC 18 months after the date of enactment of the ANGPA (or by April 2006), the secretary of energy shall conduct a study of alternative approaches to the construction and operation of such an Alaska natural gas transportation project. The study must consider the feasibility of (1) establishing a federal government corporation to construct an Alaska natural gas transportation project; and (2) securing alternative means of providing federal financing and ownership (including alternative combinations of government and private corporate ownership) of the Alaska natural gas transportation project.

1.3.3.10 Loan Guarantees (Section 116)

The secretary of energy may enter into agreements with holders of a certificate of public convenience and necessity to issue federal guarantee instruments with respect to loans and other debt obligations for an Alaska natural gas transportation project. The secretary may also enter into such an agreement with one or more owners of the Canadian portion of a natural gas transportation project. The loan guarantee is only available for two years after the date on which the final certificate of public convenience and necessity (including any Canadian certificates of public convenience and necessity) is issued for the project. The amount of loans and other debt obligations guaranteed under this section for a qualified infrastructure project must not exceed 80 percent of the total capital costs of the project, including interest during construction, or $18 billion. The term of any loan guaranteed must not exceed 30 years.

1.3.3.11 Expedited and Limited Judicial Review (Section 107)

Section 107 expedites and limits judicial review. The U.S. Court of Appeals for the District of Columbia Circuit is given original and exclusive jurisdiction to determine (a) the validity of any final agency order or action, (b) the constitutionality of any provision of ANGPA or action taken pursuant to it, and (c) the adequacy of any EIS for the project. A case seeking judicial review must be brought within 60 days of the challenged decision or action, and the Court of Appeals must set the case for expedited consideration.

1.3.4 American Jobs Creation Act (AJCA)

On October 22, 2004, Congress passed the American Jobs Creation Act (AJCA). The major provisions of AJCA pertaining to an Alaska natural gas transportation project are summarized by topic below.[12]

1.3.4.1 Certain Alaska Natural Gas Pipeline Property Treated as Seven-Year Property (Section 706)

The portion of an Alaska natural gas pipeline that is within the State of Alaska may be depreciated on an accelerated basis over seven years, rather than the current 15 years, for federal income tax purposes.[13] For purposes of this section, an "Alaska natural gas pipeline" is defined as any natural gas pipeline system (including the pipe, trunk lines, related equipment, and appurtenances used to carry natural gas, but not any gas processing plant) located in Alaska that has a capacity of more than 500 million Btu of natural gas per day (i.e., 0.0005 bcf/d) and that is placed in service after December 31, 2013. A taxpayer that places an otherwise qualifying system in service before January 1, 2014, may elect to treat the system as placed in service on January 1, 2014, in order to qualify for the seven-year recovery period.

1.3.4.2 Extension of Enhanced Oil Recovery Credit to Certain Alaska Facilities (Section 707)

The 15 percent federal income tax credit currently applied to costs related to enhanced oil recovery is extended to construction costs for a gas treatment plant capable of processing two trillion Btu of Alaskan natural gas per day into a natural gas pipeline system. The gas treatment plant must also be located in the U.S., lying north of 64 degrees north latitude (i.e., north of line approximately 62 miles south of the City of Fairbanks), and it must produce carbon dioxide which is injected into hydrocarbon-bearing geological formations. The provision is effective for costs paid or incurred in taxable years beginning after December 31, 2004.

1.4 Stranded Gas Development Act

The contract discussed in this document is the result of a process authorized by the Stranded Gas Development Act (SGDA) of 1998. The SGDA was created to help bring Alaska's natural gas resources to the market. The following subsections provide information on the history of the SGDA, its purpose, and information on the process.

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[12] The American Jobs Creation Act has become Public Law 108-357. As of June 15, 2005, the text was at: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_public_laws&docid=f:publ357.108

[13] In general, a company benefits by accelerating the depreciation of an asset when calculating taxable income by reducing tax payments in the early years of the project, when additional cash flow can be more important (e.g., in securing bonds), and deferring these taxes to later years (EIA, 2005a). A shorter depreciation period allows the pipeline to more readily secure financing for a project and successfully begin operations.

1.4.1 History and Purpose of the SGDA

The SGDA was passed by the Alaska House of Representatives on April 17, 1998, and by the Senate on reconsideration on May 12, 1998; the act was signed into law on July 7, 1998. The stated purpose of the SGDA is to:

- Encourage new investment to develop the state's stranded gas resources by authorizing establishment of fiscal terms related to that new investment without significantly altering tax and royalty methodologies and rates on existing oil and gas infrastructure and production;
- Allow the fiscal terms applicable to a qualified sponsor or the members of a qualified sponsor group, with respect to a qualified project, to be tailored to the particular economic conditions of the project and to establish those fiscal terms in advance with as much certainty as the Constitution of the State of Alaska allows; and
- Maximize the benefit to the people of the state of the development of the state's stranded gas resources.

The SGDA contemplated a process for qualification of a project, development of a contract to set the fiscal terms, and contract review. These powers were assisted by carefully described authority to receive documents from the sponsors and others and keep them confidential for certain purposes. Documents relevant to the development of the state's strategy during contract negotiations were also subject to the confidentiality protections of the SGDA.

The legislature modified the SGDA with House Bill 16. The bill amended:

- The standards applicable to determining whether a proposed new investment constitutes a qualified project;
- The standards used to determine whether a person or group qualifies as a project sponsor or project sponsor group;
- The deadline for applications relating to the development of contracts for payments in lieu of taxes and for royalty adjustments that may be submitted for consideration; and
- The conditions bearing on the use of independent contractors to evaluate applications or to develop contract terms.

The bill also provided statements of intent for the SGDA relating to use of project labor agreements and to reopening of contracts and provided for an effective date.

House Bill 16 was passed by the House of Representatives on March 26, 2003, and by the Senate on April 4, 2003; it was signed into law on April 9, 2003. The SGDA, as amended, is included in Appendix A.

1.4.2 The Municipal Advisory Group

Under the SGDA, legislature ensured that the state would address municipal concerns by creating a Municipal Advisory Group, consisting of representatives of Alaska municipalities who may be "economically affected" or "revenue affected" from gas pipeline construction and operation. For purposes of the SGDA, a municipality is considered economically affected if it will be required to provide additional public services under the terms proposed in an application. A municipality is considered revenue-affected if it will be restricted from imposing a tax, or a portion of a tax, as a result of implementation of a gas pipeline construction contract.

In January 2004, the Alaska Commissioner of Revenue appointed a Municipal Advisory Group to advise the state about issues related to municipal impacts of the gas pipeline, particularly on economic and revenue impacts to municipalities under the specific construction scenarios submitted by applicants seeking to build the gas pipeline. ADOR contracted with Information Insights, Inc., to prepare a socio-economic impact study on the municipalities and the portion of the unorganized borough areas affected by construction and operation of the gas pipeline.

1.4.3 Definition of Stranded Gas

Per the SGDA, “stranded gas” is defined as “gas that is not being marketed due to prevailing costs or price conditions as determined by an economic analysis by the commissioner of revenue for a particular project.” The term “prevailing” is interpreted to mean during the period when the gas is expected to be marketed. The ADOR recently completed an economic analysis for ANS gas that examines whether ANS gas is stranded and what it means for gas to be defined as stranded. (ADOR, 2006a) The report, in its entirety, is available in Appendix C.

The report describes the economic conditions affecting natural gas development in the state. According to AS 43.82, ANS natural gas is considered legally “stranded” if it is not currently being marketed, and would not be marketed in the near term, due to cost and/or price conditions. There are many issues that influence the cost of natural gas development. Issues discussed in the ADOR report include: history of interest in ANS gas, the energy density of gas (versus other sources of energy), natural gas supplies and market, geography and infrastructure, price forecast, scale of project, competition among projects worldwide, rate of return, fiscal stability, and Alaska LNG.

The ADOR report summarizes many of the reasons that ANS gas is considered stranded and also presents an analysis on natural gas development. The commercialization of ANS gas will be subject to market forces, with the lowest cost supplies coming to market first, and higher cost supplies shut out until the lower cost supplies are depleted. ANS gas has not been marketed due to several factors, including the distance from a market, Alaska’s geography, and the existence of vast supplies of lower cost gas in other parts of the world. ANS gas development is also subject to greater risk than that encountered by other supplies, primarily the costs of the project, potential price conditions, and competition from other sources.

Before 1998, the commercialization of ANS gas was unrealistic mainly due to low market prices that could not justify the high costs of bringing gas to market. Recent events have caused the reconsideration of ANS natural gas development. These events include: increasing U.S. natural gas prices, the Prudhoe Bay gas handling facility reaching capacity, and opportunities for loan guarantees and tax benefits for an ANS natural gas pipeline project provided by 2004 federal legislation. Many other issues still negate the development of the ANS natural gas pipeline, particularly competition from other energy projects throughout the world which have higher economic returns. There are 6,000 to 7,000 tcf of proven natural gas reserves in the world. There are about 40 tcf of natural gas discovered in Alaska, most on the ANS, of which about 32 tcf are recoverable. (Sherwood and Craig, 2001; Natural Gas Supply Association. Natural Gas Overview, n.d.) With further exploration it is believed that there may be up to 200 tcf of natural gas resources in Alaska.

Transportation cost is one of the most important differences in costs between competing gas reserves. The closest pipeline infrastructure to the ANS gas is in Alberta; however, it is likely that a decade from now it will not have sufficient capacity to handle all of the Alaska gas, and some additional pipeline capacity would be required, either with new build or expansion of existing pipeline systems. In order to understand the competitiveness of ANS natural gas, Wood Mackenzie, an energy consultant group retained by the state, estimates that Qatar's transportation costs are about $1.25 per million Btu to the east coast of the U.S. If the pipeline project to Chicago came in on budget, the projected transportation cost would be about $2.20 per million Btu—nearly 80 percent higher than the Qatar LNG cost estimate.

Another option for transportation of natural gas is LNG transport. However, this process is also very expensive; LNG shipments from the Mid-East to the U.S. are less expensive than a pipeline from the ANS to the Upper Midwest, despite the longer distance. Qatar's gas travels about 8,300 nautical miles from Qatar to New York, while ANS gas is about 4,000 miles from Chicago. However, Qatar has a lower cost of transportation (per mmBtu) because its LNG facilities are on the water's edge and transportation only involves tankers.

Another major component of costs is fiscal costs: the dollar amount producers will pay to the government in taxes and royalties. Regardless of fiscal terms today, major changes in fiscal terms after the pipeline is constructed could drastically change the project's viability. One of the major goals of the SGDA is to mitigate this risk by stabilizing state fiscal terms in order to encourage the development of stranded gas. The flexibility of collecting payments and royalties, built in to the SGDA, strives to make the major investments safer by promoting an earlier return on investment. Deferring some costs, such as property taxes during construction, allows investors to recover their investment earlier and can increase the fiscal viability of the project.

Using industry-supplied confidential information, the ADOR estimates the internal rate of return (in nominal terms) on the capital investment for the sponsor group project to be 14.1 percent when natural gas prices are at $3.50 per mmBtu. This is lower than what most alternative developing projects will earn. With a 25 percent capital cost overrun, the rate of return is reduced to 12.5 percent. With a 50 percent capital cost overrun, the rate of return falls to 11.3 percent.

ANS gas could be one of the most expensive energy resources in the world to bring to market. Other gas that is less expensive to transport to market could reduce the market price of gas, leaving ANS gas producers at risk of losing money. The ANS gas project also faces the risk inherent in very large construction projects. Not only are ordinary cost overruns very expensive, but the logistical and technological complexity increases the probability of very large cost overruns. The record of very large cost overruns (over 100 percent) on large projects is extensive. (Flyvberg et al., 2003) The expense and potential for cost overruns put ANS gas near the end of the line for competitiveness and incremental introduction into the market.

1.4.4 Process Established by the SGDA

The SGDA establishes a process by which applicants and the State of Alaska can negotiate the state fiscal terms and develop a binding contract. The application is the initial step toward the contract development process. Any draft contract that is developed through negotiations between a sponsor and the state would be subject to at least a 30-day public review and comment period, and then consideration by the state legislature. If authorized by the legislature, the governor may execute the contract. The steps of this process are outlined below:

- Administration accepts applications from entities interested in building an Alaska natural gas pipeline, shipping gas through that pipeline, or both building the pipeline and shipping gas.
- Administration determines if a proposal is a qualified project submitted by a qualified sponsor or sponsor group.
- If the proposed project and sponsor or sponsor group are determined to be qualified, Administration negotiates with applicants on royalty adjustments, payment in lieu of one or more taxes, hiring of Alaska residents and contracting with Alaska businesses, and other terms. The Administration must notify each revenue-affected and economically affected municipality.
- If the Administration successfully concludes negotiations with an applicant, it prepares a preliminary finding and a determination (this document) in which it reports the facts and makes decisions based on those facts whether the contract is in the long-term fiscal interest of the state.
- The Administration provides a minimum of 30 days for public and legislative comment and must offer to appear before the Legislative Budget and Audit Committee for a discussion of proposed contract and other documentation. According to AS 43.82.440, a person may not bring an action challenging the constitutionality of a law authorizing a contract enacted under the SGDA or the enforceability of a contract executed under a law authorizing a contract enacted under the SGDA unless a lawsuit is brought in the superior court within 120 days after the date that the contract is executed by the state and the sponsors.
- Following the comment period, the Administration has 30 days to prepare a final fiscal interest finding if it is to proceed with the proposed contract.
- The Administration submits final proposed contract to the legislature with request for authorization to sign the contract.
- If the authorization by the legislature is provided, the governor and all parties must execute the contract, after which the contract becomes binding.

More detailed descriptions of some of these steps are provided in the sections that follow.

1.4.4.1 Application Process

The application process includes procedures to determine whether the project and the sponsor (or sponsor group) are qualified under the SGDA, and the information that needs to be submitted with the application.

Project and Sponsor Qualification Procedures

There are a number of criteria that are used to determine if a project and the sponsor (or sponsor group) are qualified. To provide a complete and accurate description of the application process set forth in the SGDA, the language of the Alaska statute relevant to these procedures is reproduced here in a near-verbatim form.

Under AS 43.82.100, the commissioner of revenue, based on the information available, may determine that a proposal for new investment is a qualified project if the project:

- Principally involves:
  - The transportation of natural gas by pipeline to one or more markets, together with any associated processing or treatment;
  - The export of liquefied natural gas from the state to one or more other states or countries; or
  - Any other technology that commercializes the shipment of natural gas within the state or from the state to one or more other states or countries;
- Would produce at least 500 bcf of stranded gas within 20 years from the commencement of commercial operations;[14] and
- Is capable, subject to applicable commercial regulation and technical and economic considerations, of making gas available to meet the reasonably foreseeable demand in this state for gas within the economic proximity of the project.

Under AS 43.82.110, the commissioner of revenue may determine that a person or group is a qualified sponsor or qualified sponsor group if the person or a member of the group:

- Intends to own an equity interest in a qualified project, intends to commit gas that it owns to a qualified project, or holds the permits that the department determines are essential to construct and operate a qualified project; and
- Meets one or more of the following criteria:
  - Owns a working interest in at least 10 percent of the stranded gas proposed to be developed by a qualified project;
  - Has the right to purchase at least 10 percent of the stranded gas proposed to be developed by a qualified project;
  - Has the right to acquire, control, or market at least 10 percent of the stranded gas proposed to be developed by a qualified project;
  - Has a net worth equal to at least 10 percent of the estimated cost of constructing a qualified project; and/or
  - Has an unused line of credit equal to at least 15 percent of the estimated cost of constructing a qualified project.

[14] Commencement of commercial operations is defined as the day the mainline is placed into service.

Project Plan Qualification Procedures

As set out in AS 43.82.120, a qualified sponsor or sponsor group may submit to the ADOR an application for development of a contract evidencing that the qualification requirements are met. Along with an application, an applicant shall submit a proposed project plan that contains the following information based on the project definition at the time of application:

- A description of the work accomplished as of the date of the application to further the project;
- A schedule of proposed development activity leading to the projected commencement of commercial operations of the project;
- A description of the development activity proposed to be accomplished under the proposed project plan;
- A description of each lease or property that the applicant believes to contain the stranded gas that would be developed if the project was built;
- A description of the methods and terms under which the applicant is prepared to make gas available to meet the reasonably foreseeable demand in this state for gas within the economic proximity of the project during the term of the proposed contract, including proposed pipeline transportation and expansion rules if pipeline transportation is a part of the proposed project;
- A detailed description of options to mitigate the increased demand for public services and other negative effects caused by the project;
- A detailed description of options for the safe management and operation of the project once it is constructed; and
- Other information that the commissioner of revenue, in consultation with the commissioner of natural resources, considers necessary to make a determination that:
    - The work accomplished as of the date of application, the schedule of proposed development activity, and the development activity proposed to be accomplished under the proposed project plan reflect a proposal for diligent development on the part of the applicant;
    - The proposed project plan does not materially conflict with the obligations of a lessee to the state under a lease or under a pool, unit, or other agreement with the state; and
    - The proposed project plan describes satisfactory methods and terms for accommodating reasonably foreseeable demand for gas in this state within the economic proximity of the project during the term of the proposed contract.

A proposed project plan may be approved as a qualified project plan under AS 43.82.130 if the proposed project plan:

- Reflects a proposal for diligent development of the project on the part of the applicant;
- Does not materially conflict with the obligations of a lessee to the state under a lease or under a pool, unit, or other agreement with the state; and

- Describes satisfactory methods and terms for making gas available to meet the reasonably foreseeable demand in this state for gas within the economic proximity of the project during the term of the proposed contract.

Under AS 43.82.140, the commissioner of revenue shall review an application and has the sole authority to determine whether the project is qualified under Section 43.82.100, and whether the applicant is qualified under Section 43.82.110. The commissioner of revenue may approve an application only if those provisions have been met. If the application is approved, the commissioner of revenue, together with the commissioner of natural resources, reviews the proposed project plan submitted with the application to determine whether it is a qualified project plan under AS 43.82.130. The commissioner of revenue may approve the proposed project plan as a qualified project plan only if the commissioner of natural resources concurs in the approval.

1.4.4.2 Negotiation Process

Under the SGDA, the commissioner of revenue is authorized to negotiate fiscal certainty for an extended period of time regarding taxation and other applicable issues with the qualified applicants who propose to build the gas pipeline that will bring ANS gas to markets in Alaska, Canada, and the lower 48 states.

The SGDA, at AS 43.82.200, provides that, if the commissioner of revenue approves an application and proposed project plan, the commissioner may develop a contract that may include:[15]

- Terms concerning periodic payment in lieu of one or more taxes as provided in AS 43.82.210;
- Terms developed under AS 43.82.220 relating to:
    - Timing and notice of the state’s right to take royalty in kind or in value; and
    - Royalty value;
- Terms regarding the hiring of Alaska residents and contracting with Alaska businesses under AS 43.82.230;
- Terms regarding periodic payment to, or an equity or other interest in a project for, municipalities under AS 43.82.500;
- Terms regarding arbitration or alternative dispute resolution procedures;
- Terms and conditions for administrative termination of a contract under AS 43.82.445; and
- Other terms or conditions that are:
    - Necessary to further the purposes of this chapter; or
    - In the best interests of the state.

[15] The scope of the terms that could be negotiated would be expanded by the proposed conforming legislation. The negotiated terms of the contract are discussed in Section 3 of this document.

1.5 The State's Guiding Principles and a Development Concept for the Future

In the negotiation process, the state was guided by six principles intended to ensure that its grand concept for the development of a natural gas industry goes beyond just a pipeline project. The state envisions a natural gas industry that will generate economic diversity, create fiscal stability, and increase the economic vitality of Alaska.

1.5.1 The Governor's Six Gas Pipeline Principles

(1) **Alaskans deserve a fair share of revenues from a gas pipeline.** The increase in state revenues from the project will benefit all Alaskans. The revenues that accrue to the state will help support programs that promote quality education, provide healthy and safe communities, and protect Alaska residents.

(2) **Alaskans need the opportunity to access the gas.** There is a growing shortage of Cook Inlet gas sources and a new source of energy is critical to the Railbelt and Southcentral, not only to support residential and commercial needs, but also to fuel industrial operations. Affordable energy is also vital to village economies throughout Alaska.

(3) **Future explorers must have access to the gas pipeline.** Exploration and development opportunities for new market entrants are important for the long-term sustainability of Alaska's economy. An environment that fosters new market entrants could only encourage a stronger and healthier economy.

(4) **The gas pipeline must be expandable.** New discoveries must get to markets so Alaska could achieve maximum benefit from the gas pipeline. The flexibility to expand pipeline capacity would ensure that market demands are met at the right time and maximum revenues are achieved.

(5) **The state should share in the wealth by owning a share of the gas pipeline.** Gas pipeline ownership will provide a stable, steady revenue stream. Ownership will also give the state a "seat at the table" to protect Alaska's interests.

(6) **Alaskans deserve Alaska gas pipeline jobs.** New direct and indirect jobs will be created in Alaska during pipeline construction and beyond. The goal is to ensure that Alaskans are considered first for pipeline jobs, particularly for so-called "legacy" jobs that will be available even after the construction period. Training programs are being implemented to ensure Alaskans are ready and well-equipped for these jobs.

1.5.2 The Alaska Development Vision

The state envisions a project that goes beyond just a pipeline project. The concept for the development of a natural gas industry includes high paying jobs for Alaska residents, additional oil and gas development, and even potential commercialization of gas hydrates and the establishment of a petrochemical industry. The concept strives for the kind of economic diversity and vitality achieved by Alberta, Canada—an industry leader in oil and gas.

1.5.2.1 Local Hire

The development vision calls for more jobs for Alaska residents. More jobs for Alaska residents means more income is retained within the state. The oil and gas industry provides the highest annual average wages in Alaska, about $96,000 compared to the all-industry average of about $37,000 (ADOLWD, 2003). Oil and gas industry workers are known not only for their high pay, but also for their high skill and experience level. Giving Alaskans the opportunity to obtain these jobs will create a well-trained, highly skilled, and experienced local work force; which in turn will create lasting benefits for the entire state.

1.5.2.2 Additional Oil and Gas Development

The development vision calls for additional oil and gas development in the state so that the state can generate additional revenues on oil and gas resources. The construction of the pipeline will provide a catalyst for increased oil and gas exploration, development, and production activity throughout the state. Federal and state geologists believe that the 35 tcf of known gas resources in Prudhoe Bay and Point Thomson are just part of a larger reserve. It is the intent of the state that the incentives provided by the contract will lead to exploration for and discovery of new gas so that the gas pipeline will be filled to capacity throughout its useful life. Investments in exploration, development, and production would generate additional jobs, increase value-added opportunities, and further expand the oil and gas support sectors, thereby generating even higher state and local revenues.

1.5.2.3 Alaska—the Next Alberta

The development vision calls for Alaska to emulate Alberta, Canada. Alberta is one of the world's top energy producers with vast reserves of oil and natural gas. In 2003, Alberta accounted for 66 percent of Canada's conventional oil, 81 percent of Canada's natural gas, and 100 percent of Canada's bitumen and synthetic oil. In the same year, Alberta's marketable natural gas deliveries totaled 4.97 tcf, and their production of natural gas liquids (ethane, propane, and butanes) totaled 101 million barrels, valued at $2.5 billion (Canadian). Alberta holds a 12 percent share of the U.S. natural gas market; the U.S. market accounts for approximately 62 percent of Alberta's gas sales (Alberta Economic Development, 2005).

The chemical and petrochemical industry is a major manufacturing industry and a key contributor to Alberta's economy. The industry produces over $9.5 billion (Canadian) worth of products annually. The industry comprises petrochemicals, fertilizers, inorganic chemicals, and specialty and fine chemicals.

Given Alaska's resources—the flow of four bcf/d of gas from ANS and ten million gallons per day of natural gas liquid (NGL) accounting for at least five percent of total North American gas and NGL sales (Alberta Economic Development, 2003)—the state has the potential to create a strong natural gas industry, and eventually achieve the level of technology infrastructure, knowledge base, and favorable business environment that made Alberta an industry leader in oil and gas.

1.6 Negotiations with the Sponsor Group

The State of Alaska conducted lengthy negotiations with the sponsor group resulting in the contract that is the focus of this document. The state and the sponsor group negotiated a business relationship, where the ultimate goal was to achieve areas of alignment that would help move the project forward.

Typically, businesses and governments are not likely to agree about what constitutes the best business relationship due to the conflicting nature of their interests. Business wants to maximize profits, and can best do so when governments agree to absorb risks and pay for costs that the business would otherwise shoulder, such as taxes, infrastructure, and training. Public interests, on the other hand, are more complex and diffuse because there are multiple stakeholders involved. Governments generally want more revenues to provide more public services, yet they also want to foster a business environment that will strengthen their economic base by retaining and attracting businesses at minimal expenditure.

While the best result for each party may never be reached, there is an area where mutual gains may be achieved, because public and private interests are interdependent and both parties need the other in order to attain their objectives. In this case, both parties would like to advance a gas pipeline project that is economically viable, because both parties view this undertaking as beneficial to their welfare. However, the natural gas pipeline project faces significant risks as a result of the multi-billion dollar cost of the project. Such a project could have significant cost over-runs. Additional risk will be present because operations of the project will be highly sensitive to global and domestic supply and demand of natural gas, and the resulting future market prices.

The negotiation process was crucial in achieving an acceptable outcome for the state and the sponsor group. The negotiation process was an important and complex undertaking for all parties for several reasons:

- The state wanted to develop a strategy to provide incentives to explore for and discover oil and gas resources so a stable amount of revenue is realized for the future;
- Fiscal certainty for the producers group is important in reducing risks involved in a project of this magnitude;
- There are multiple stakeholder interests, including the state, affected municipalities, in-state users of natural gas, the producers group, independent explorers, and future shippers;
- The contract would create stability by providing exemptions from taxes or a right to pay certain taxes subject to state reimbursement for fiscal obligations owed to the state and municipalities.

The State of Alaska is participating in the project by sharing in the risks as a pipeline owner. By doing so, the state also expects to collect revenues from the pipeline operations and to gain a “seat at the table” to ensure that the interests of the state are represented during project development and when pipeline operations begin. The producers group seeks fiscal certainty and stability to help mitigate the risks of this pipeline project.

Given that the state negotiated as an equity participant and shipper, the negotiations were conducted at arms-length where all parties carefully considered their risk-reward balance.

The state considered the rewards and risks of participating in the pipeline project and the producers considered the rewards and risks of undertaking a multi-billion dollar project that will affect their business positions in the global oil and gas markets.

1.6.1 Due Diligence and Verification

The contract is the result of a careful process of investigation with expert assistance on the issues that would attend to a stranded gas contract followed by extended negotiations on the precise terms of a contract. Literally thousands of hours of time were spent in this process by high-level state officials, state staff, and outside consultants.

At the highest level, the objectives of the gas negotiating team were set by the governor after consultation with his chief of staff and the gas cabinet. The gas cabinet included the commissioner of revenue, the commissioner of natural resources, the attorney general, and a dedicated group of deputy commissioners, and, as appropriate, senior staff from the departments. The gas cabinet met hundreds of times to review and approve the actions that were taken to implement the governor's objectives.

Even before the first qualifying SGDA application was received in January 2004, the state team met to define the issues that would arise in the SGDA negotiations. This process intensified after the applications were received in January 2004. For example, in the winter and spring of 2004, the state contracted for representatives from the largest investment houses to make presentations on the financing and development issues that they viewed as critical with respect to an Alaska gas pipeline. UBS-Warburg, Goldman Sachs, Merrill Lynch, and three other leading firms made presentations. The state also assembled a team of key consultants to prepare the state for the negotiations and to assist in the negotiations.

1.6.1.1 The Discussions and Analyses

After the sponsor group application was accepted, the state entered into discussions identifying and exploring the core issues that would set the agenda for a stranded gas contract. The discussions had two dimensions. The state and the sponsor group conducted a series of workshops focusing on such issues as the kinds of fiscal stability that would be needed for the project, how the state and shippers would obtain capacity on the pipeline, the regulatory approval process and timeline for any project, the economics, markets and sources of supply for the project, financing plans, and many other issues. The state independently analyzed many of the same issues through consultants and independent advisers. The state analyzed the federal tax and state law issues that would arise if the state chose to participate in the ownership of the pipeline and gas treatment plant, as well as parallel but separate questions that would arise from the state directly marketing its own gas. The state also retained Canadian counsel and corporate advisers to inform it about regulatory, aboriginal, and governmental issues in Canada. Representatives of the state also were in contact with relevant staff of FERC, the Department of Energy (DOE), the Department of the Interior (DOI), Congress, and the White House, and informally discussed questions that arose as the issues were framed and the negotiations progressed.

1.6.1.2 Consultants

A core adviser to the state was Pedro van Meurs, a leading international petroleum economist and negotiator. Dr. van Meurs has long experience representing governments exclusively in designing petroleum taxation regimes and in petroleum negotiations. In his career, he has represented more than 70 sovereigns in such negotiations, including countries such as Algeria, Vietnam, China, Kuwait, Bolivia, and Mexico. Dr. van Meurs served as lead economic adviser to the state on the Alaska gas negotiations and has devoted a significant amount of time to the state's investigation and negotiations in connection with this project. Dr. van Meurs was also a key adviser to the state in designing the new petroleum profits tax (PPT).

Dr. van Meurs served as lead negotiator for the state through the late spring of 2005. After that, he served as the senior economic adviser to the gas negotiations. Jim Clark, the governor's chief of staff, became lead negotiator in May 2005 and since then has devoted himself full time to the negotiations.

Early in the process, the state also retained Lukens Energy to advise the state on a wide variety of issues concerning gas pipelines and gas markets. Jay Lukens, who holds a Doctorate in Economics and is the founder of the company, is an internationally recognized expert in natural gas markets and regulation with broad experience in the lower 48 pipeline industry, including service as director of rates for TransCo pipeline. Two of his partners, Scott Smith and Dan Ives, also have highly relevant experience. Dan Ives has extensive experience with FERC gas rate issues and served in leadership positions at three major natural gas pipeline and distribution companies, including a role as vice president of rates and regulatory affairs at ANR Pipeline Company. Scott Smith has over 20 years of energy industry experience, including directing energy commodity and derivatives origination as a vice president of Southern Company Energy Marketing, L.P. Mr. Smith also served as vice president and general manager of Vastar Power Marketing, Inc. Lukens Energy has rendered consulting services for a wide variety of clients, including the Minerals Management Service of the DOI, domestic pipelines and distribution companies, and energy producers.

In the fall of 2005, the state hired a financial advisory group consisting of Challenger Capital Group, Credit Suisse First Boston, and UBS Investment Bank and Financial Service to advise on the state's financing of its ownership interest in the project. The Challenger team has over 20 years of investment banking experience and extensive experience advising clients in the natural gas sector, including providing financial and structural advice in connection with the Kern River Gas Transmission project and the Transgas pipeline from Algeria to Portugal. The Credit Suisse First Boston team is led by Steve Greenwald, a senior member of the firm's energy group and global head of project finance. Mr. Greenwald has worked on more than 150 projects around the world with an aggregate value in excess of $100 billion. Municipal finance advice was provided by UBS Financial Service, headed by Bob Doherty. Mr. Doherty has over 18 years of banking experience and is a managing director and co-head of the firm's national infrastructure group. Mr. Doherty has provided advice in connection with some of the largest and most complicated municipal finance transactions completed to date. UBS Investment Bank is represented by Wallace Henderson, a managing director in the firm's global energy group. Mr. Henderson has nearly 20 years experience advising clients in connection with international oil and gas projects. Legal advice to the financial advisor group was provided by Bill Voge and Ken Schuhmacher of Latham & Watkins. Mr. Voge is a partner in the firm's New York office and is recognized as one of the leading attorneys in the U.S. in the project finance area. Mr. Schuhmacher is a partner with extensive experience representing lenders and owners/developers in project financings in the U.S. and abroad.

Legal services were provided by the state's attorney general's office, by Morrison and Foerster, and by Preston Gates & Ellis LLP. Bob Loeffler led the Morrison and Foerster delegation, joined by Peter Hanschen, Nick Spiliotes, Ed Twomey, and other tax, regulatory, and business lawyers as needed. Mr. Loeffler has represented the state on pipeline and energy matters for more than three decades. From 1974 to 1982, he represented the state in congressional and executive branch process on the ANGTS. He was involved in all of the state's oil pipeline litigation and in aspects of its royalty and tax cases, and he represented the state with respect to the BP-ARCO merger. Mr. Loeffler also represented a variety of other energy industry clients, both private and public, in FERC and state administrative proceedings. He is listed by Chambers as a leading energy lawyer, was a director of the Energy Bar Association, and for two terms chair of the administrative law section of the DC Bar. Peter Hanschen, also recognized by Chambers, is an expert on gas pipeline regulatory issues, having served as general counsel of an interstate pipeline, Pacific Gas Transmission, and as deputy general counsel of PG&E, the nation's largest utility, before entering private practice. Ed Twomey is also an expert in federal and state energy regulatory matters. He was the lead counsel in the cost of service phase of the TAPS litigation and worked on that litigation from its outset. Nick Spiliotes is chair of Morrison and Foerster's 500 lawyer business department and is a leading project finance attorney. He has represented lenders and, particularly, quasi-governmental lenders on a number of large international power projects

Preston Gates & Ellis LLP provided advice on a variety of public finance, tax, state law, and legislative matters. Cynthia Weed, Louann Cutler, Joe Donohue, and Wilson Condon comprised the core team that assisted the state. Ms. Weed has served as the state's Bond Counsel for many years. She has almost thirty years of experience in public finance and has worked with numerous states and municipalities in Alaska and the Lower 48. Mr. Donohue represented the state in several major oil and gas tax cases and in the Exxon Valdez oil spill litigation, and also represented the Alaska State Legislature in the Arco-BP merger investigation. He was Deputy Commissioner of ADOR from 1979-1984. Mr. Condon has previously served as Deputy Attorney General (1975-1980), Attorney General (1980-82) and Commissioner of Revenue (1995-2002), and most recently served as the head of the Department of Law's oil, gas and mining section. He has represented the state in extensive and complex royalty and tax oil and gas litigation. Ms. Cutler represents the state and municipal clients in complex oil and gas tax litigation, and has extensive experience with drafting legislation, ordinances, and regulations. She worked from 1981-1987 as a special assistant to the Chair of the House Finance Committee on oil and gas tax legislation and other matters.

Other experts who were consulted included the Petroleum Finance Corporation of Washington, D.C., which investigated the comparative economic attractiveness of the Alaska gas project with other oil industry investment opportunities worldwide; Osler, Hoskin and Harcourt, LLP, a Canadian law firm with expertise in negotiating agreements with the oil industry, Canadian regulatory issues, and Canadian corporate law issues; Wood Mackenzie, a leading international authority on gas and oil industry trends; and Paragon Engineering

Company of Houston, Texas, which was consulted with respect to technical issues such as expansion.

Appendix D contains a list and description of other consultants and firms that assisted in the analysis and preparation of this document.

1.6.1.3 Expertise Contributed by State Employees

The state's negotiating team was supported not only by external consultants, but by a large group of experienced state employees. In the ADNR and ADOR, the state had a seasoned group of petroleum economists who developed sophisticated economic models that were used to evaluate various alternative project options as well as to project state benefits. ADNR staff included expertise on gas marketing, public utility ratemaking, royalty, lease terms, unit administration, auditing, and oil and gas engineering. The gas team also tapped ADOR experts on the administration of the state's ad valorem, production, and corporate income taxes and on auditing and accounting issues.

Attorneys from the Department of Law contributed expertise on Alaska constitutional and governmental law, as well as tariff, royalty, and tax issues that had been litigated over several decades. On Alaska hire issues, the gas team utilized the expertise of the Department of Labor in enforcing the state's employment laws.

The expert staff of other departments was consulted as appropriate for specific issues.

1.6.2 The Negotiations and Core Issues

The full scale negotiations with the sponsors started in February 2004. The idea of risk sharing on the part of the state was developed and presented to the legislature in a special presentation on April 7, 2004. A comprehensive risk sharing and participation proposal to the sponsors was developed by the end of July 2004. This proposal was discussed in depth with the sponsors.

In October 2004, an opening offer on fiscal terms was presented by the state. The state received a counter offer from the sponsor group in December 2004 that included a relatively complete draft contract. The state had independently drafted its own proposed contract.

Once the state and the sponsor group exchanged competing proposals, including draft contracts, negotiations intensified. Beginning in the late spring of 2005, the state and sponsor group engaged in negotiations on a seven day-a-week basis. In 2005, nearly all of the negotiations were conducted in Anchorage, but in 2006 the meetings were moved to Juneau. Negotiations proceeded not only on an issue-by-issue or clause-by-clause basis, but also on the basis of the overall fiscal terms (economic package) that each side was offering. At times the issues were resolved in principle and then reduced to writing. At other times, it best served the parties' interests to exchange drafts of competing concepts and endeavor to blend the drafts into one product. No major issue was easily resolved, and a few key articles took literally months of work to resolve. At several points, issues were escalated to the highest level, resulting in meetings between the Governor, the chief executive officers of EM and CP, and a high ranking representative of BP.

For most of 2005, the state negotiated with the three companies. When the state made proposals or counterproposals, these three companies independently reached a consensus position before responding to the state and this added to the length of the process. That changed in October 2005, when the state reached an agreement in principle with CP. That agreement was documented over the next month. From that point forward, the negotiating dynamic changed. CP and the state, on the one hand, and EM and BP, on the other, worked to reach consensus. The agreement with CP became the platform for resolving all of the issues with BP and EM.

There was a parallel process conducted with respect to the mainline limited liability corporation (LLC) and financing issues. A separate state team supported by the law firm Morrison and Foerster led those negotiations. The companies also fielded a somewhat separate team to advance the LLC negotiations. Otherwise, one set of negotiations would have followed the other, ultimately delaying the project. The LLC negotiations are ongong. Preston Gates & Ellis LLP prepared the legislation to create the entity that would hold the state's interest in the pipeline (the Alaska Natural Gas Pipeline Corporation). Because of the linkage between that and the LLC negotiations, they also provided substantial assistance to that process. The issue of how the state would finance its participation in the mainline called for high level assistance from the state's financial advisory team. Their worldwide experience in financing projects, including some in which the three sponsor companies had been involved, was invaluable.

Briefly, the major structural elements of the negotiations centered on the issues of:

- Determining the extent and terms of state's participation in the project;
- Creating a durable and stable fiscal regime;
- Establishing work commitments;
- Aligning of interests in the pipeline project with the state's 20 percent equity ownership;
- Taking royalty and production tax in kind;
- The parties' capacity commitment to ship their own gas; and
- Payments in lieu of taxes.

These elements were crucial bargaining issues in the negotiating process. The negotiation between the state and the sponsor group has been a lengthy process of give and take. This particular contract is essentially a business relationship that required special considerations and concessions by all parties.

The negotiations were conducted in a confidential manner to protect the applicants' confidential information and to protect the long-term fiscal interests of the state as provided under AS 43.82.310.

2 Project Description

The following sections describe the key elements of the project.

2.1 Overview

The project includes building a natural gas pipeline and related facilities, with a design capacity to transport approximately four bcf/d of stranded gas from the ANS to markets in Canada and the lower 48 states (see Figure 12). The pipeline will cross several federal, state, and local government jurisdictions in addition to privately owned land.

The project would consist of a large diameter, large volume pipeline delivering Alaska gas to North American markets. The project would transport approximately 51.1 tcf of natural gas over the anticipated 35-year operating life of the facility.

Figure 12. Alaska Gas Pipeline Route

Source: ADNR, 2006.

In 2001, the sponsor group developed a detailed cost estimate of about $18.5 billion for a project including a gas treatment plant, a pipeline from Alaska to Alberta, a NGL plant, and a pipeline from Alberta to Chicago. To avoid disclosing confidential information, this estimate was subsequently rounded to $20 billion and updated to 2003 dollars. Since that time, the inflation index for capital equipment (i.e., Bureau of Labor Statistics (BLS) Commodity Price Index WPUUSOP3000) has averaged 1.9 percent per year, while the inflation index for other pipelines (i.e., BLS Industry Price Index PCU 4869-- 4869--) has averaged 2.6 percent per year. Using this range of inflation, the cost estimate was adjusted to $21 billion, in 2005 dollars.

The pipeline system has been designed in two segments. The first segment runs from Prudhoe Bay to Alberta, Canada. This segment is a new build of 2,140 miles and would roughly parallel TAPS and the Alaska Highway. The second segment is a 1,500-mile pipeline which is currently visualized as a new build from Alberta to Chicago. An alternative to building this section of the pipeline would be to utilize existing expansion if it were competitively priced. In total, the pipeline system would consist of 3,600 miles of 48 to 52 inch high pressure pipeline and would include 24 compressor stations. According to estimates from the sponsor group, the construction project would require 54 million construction man hours, five to six million tons of steel, 134 loaders, 275 automatic welders, 665 sidebooms, 18 trenchers, 250 backhoes, 236 large dozers, 125 stringing tractors, 1,300 pickup trucks, and 230 buses.

The estimated costs for various components of the project are presented in Table 2. It should be noted that the values shown are in 2005 dollars. This estimate would be revised as the project becomes better defined, following completion of the engineering and design work.

Table 2. Preliminary Cost Estimates of the Project Components

Component	Amount ($ billion, 2005)
GTP	$2.6
Alaska Pipeline (Prudhoe Bay to Yukon border)	$5.1
Canadian Pipeline (Yukon border to Alberta)	$5.9
Total Cost to Alberta	$13.6
Estimated Cost from Alberta to Chicago	$7.4
Total Cost to Chicago	$21.0

Source: ADOR.

Note: This cost estimate does not include the cost of building the Pt Thomson feeder line; this is estimated to cost an additional $0.6 billion.

2.2 Physical Components

2.2.1 Gas Treatment Plant (GTP)

The GTP would be located on ANS and would be designed to remove carbon dioxide (CO_2), hydrogen sulfide (H_2S), and other impurities from the natural gas stream to meet inlet pipeline specifications. These pipeline specifications would also require that the gas be compressed and chilled.

2.2.2 Mainline

The pipeline consists of 48 to 52-inch, high-pressure buried pipe operating at approximately 2,500 pounds per square inch (psi). This large diameter gas pipeline will be located in Alaska along the TAPS and Alaska Highway. Compressor stations would be placed at regular intervals to maintain the pressure. In permafrost regions, the gas would be chilled to manage the mechanical strains on the pipe and mitigate any potential impact on frozen soils.

2.2.3 Gas Transmission Pipelines

The GTP and mainline will receive gas from a number of different fields including the Point Thomson, Kuparuk, North Star, Milne Point, Badami, and Colville River Unit fields. Each of these fields will connect to the GTP and mainline through the gas transmission pipelines.

2.2.4 Alaska – Alberta Pipeline

The Alaska to Alberta pipeline route would originate in the Prudhoe Bay Unit and parallel the Dalton Highway southward to Fairbanks, and then parallel the Richardson and Alaska Highways from Fairbanks through the Yukon and extreme northeastern British Columbia into Alberta, traversing a total of approximately 2,140 miles.

2.2.5 Natural Gas Liquids (NGL) Plant

A NGL plant is expected to be included in the project to allow export and subsequent recovery of hydrocarbon products that are currently too light to blend with crude oil for delivery through the TAPS. This NGL removal would likely be required in order to condition the natural gas to meet downstream market specifications. This NGL removal could be achieved through a new-build plant, through utilization of existing plant capacity or some combination thereof.

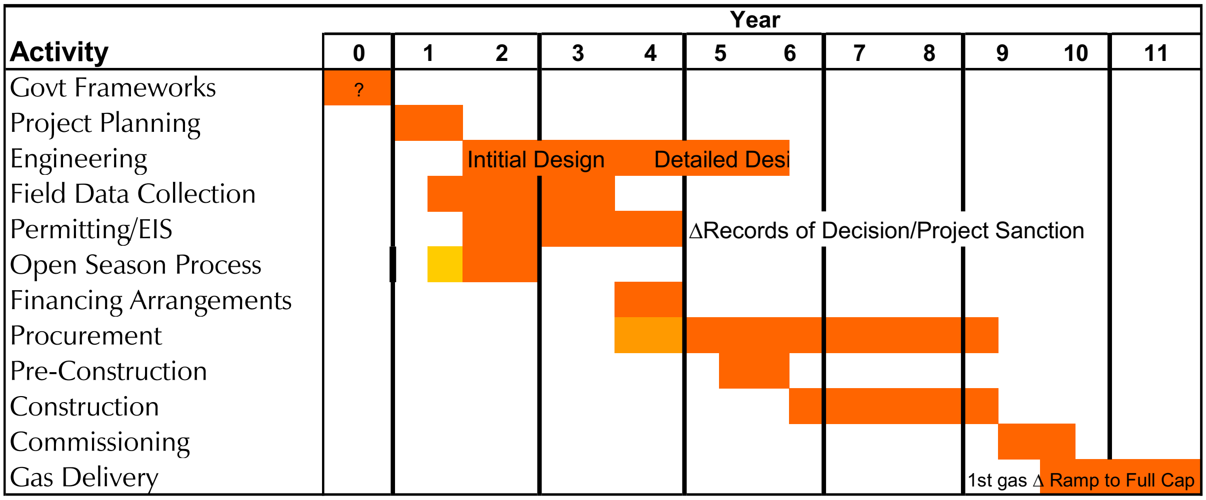
2.2.6 Alberta – Lower 48 Exports

The final portion of the project involves the export of gas from Alberta. As noted earlier, one option is a potential "new-build" pipeline system from Alberta to Chicago to provide this Alberta take-away capacity. Alternatives include utilizing existing pipeline capacity made available by decline in existing sources, expansion of existing pipeline systems, or installation of other "new build" pipeline concepts.

2.3 Conceptual Project Timeline

The sponsor group's SGDA application provided a conceptual timeline for the development of their proposed gas pipeline project. This timeline is illustrated in Figure 13.

Figure 13. Sponsor Group Conceptual Project Timeline



Source: Based on Sponsor Group’s SGDA Application.

3 Review of the Contract Articles

This section provides a review of the major terms and conditions of the Alaska Stranded Gas Fiscal Contract. The parties to the contract—the State of Alaska, BP, CP, and EM—have negotiated and agreed to 40 of 41 articles pertaining to various terms and conditions that would provide fiscal certainty to the sponsor group and help facilitate the construction of a natural gas pipeline. Article 14, Payments in Lieu of Production Taxes is still being negotiated. In part, negotiations are delayed by the completion of the PPT statute currently under deliberation by the legislature. This document had to be finalized for transmittal to the printer prior to completion of these articles in order to be available for release as soon as possible. Updates to this document incorporating the final articles will be issued when complete.

The following major items are summarized in this section:

- State ownership
- Fiscal terms of the deal
- Alaska hire and content
- Capacity management
- Work commitments
- In-state markets
- Dispute resolution

Sections of the contract that relate to communications, relationship of the parties, remedies, representations and warranties, and interpretation of the contract are important for administering the contract. These administrative provisions were considered in making this finding and determination, but are not discussed in this section. A more detailed article-by-article description of the contract is provided in Appendix E: *Contract Summary by Article*.

Table 3. List of Articles in the Alaska Stranded Gas Fiscal Contract

Number	Title of the Article
Article 1	Definitions
Article 2	Drafting Conventions
Article 3	Term
Article 4	Qualified Project Description
Article 5	Work Commitments
Article 6	Alaska Hire and Content
Article 7	State Ownership
Article 8	Regulation of and Access to Project Facilities and Disposal Services
Article 9	In-State Markets
Article 10	Capacity
Article 11	Fiscal Stability
Article 12	Royalty Payments
Article 13	Tax Bearing Gas Payment
Article 14	Payments In Lieu of Production Taxes
Article 15	Upstream Facilities Payments
Article 16	Midstream Payment
Article 17	Payment In-Lieu of Oil Pipeline Ad Valorem Taxes
Article 18	Impact Payments
Article 19	Payments In Lieu of State Corporate Income Tax
Article 20	Cost Allowances
Article 21	Payments to Political Subdivisions
Article 22	Payment of Fiscal Obligations
Article 23	Point Thomson
Article 24	Measurement
Article 25	Audit
Article 26	Mandatory Dispute Resolution
Article 27	Judicial Challenge and Order
Article 28	Administrative Termination
Article 29	Confidentiality
Article 30	Contract Administration and Notice
Article 31	Assignment, Addition, and Withdrawal
Article 32	No Joint Marketing
Article 33	No Third Party Beneficiaries
Article 34	No Agency
Article 35	*Force Majeure*
Article 36	Inflation Adjustment and Interest
Article 37	Liability and Limitation on Damages
Article 38	Interpretation Provisions
Article 39	Parts of this Contract
Article 40	Representations and Warranties
Article 41	Relationship to Law and other Agreements

3.1 State Ownership

The contract (Article 7) includes provisions for state ownership of the gas resources and the project facilities/infrastructure. The state proposes to take royalty payments as gas instead of cash, and has negotiated ownership positions, or options for ownership of the project facilities.

The State of Alaska owns much of the surface and subsurface estate on the ANS, outside of the federally-owned NPR-A, and ANWR. The producers hold the leases to the land that contains 94.3 percent of the proven North Slope natural gas reserves. The producers possess legal interests in the oil and gas reserves and the state collects royalties as owner of the subsurface estate. There will be no change in the state's royalty share under the contract; the state retains 12.5 percent or greater royalty on oil and gas produced from state-owned lands on the ANS (See Article 12).

Under Article 7 of the contract, the state has negotiated ownership positions, or options for ownership, in a number of project components. These include:

- A 20 percent ownership position in the gas treatment plant (GTP), a natural gas liquids (NGL) plant if located in Alaska, the main pipeline from the ANS to the Alaska-Canada border (mainline), and the pipeline and associated facilities from the Alaska-Canada border to Alberta (the Alaska to Alberta Project)[16];
- An ownership position in the pipeline and associated facilities from Alberta to the Lower 48 states[17] commensurate with the expected throughput of state gas (gas received as royalty and production tax payments);
- An ownership position in the gas transmission pipeline from the Point Thomson unit to the GTP or the mainline commensurate with the expected throughput of state gas;
- An option to own or ownership position in the gas transmission pipeline from the NPR-A to the mainline and other fields in the North Slope, depending on the date of project sanction for the gas transmission pipeline. The level of option or ownership position would be commensurate with the expected throughput of state gas; and
- An option to own an interest in other gas transmission pipelines.

In determining to take state ownership, the state weighed a number of factors in order to determine the organizational structure that will provide the best combination of benefits under tax and other relevant laws and regulations. For example, the state had to consider, among other factors, whether the state should own its interests in the pipeline and the gas directly or through newly formed state entities, as well as the impact of U.S. and Canadian rules and laws. The state also had to weigh various options for financing the contributions of debt and equity it will be required to make to the project and issues related to how the state could participate in the development, construction, and operation of the pipeline without conflicting with the state's separate regulatory and oversight functions.

[16] This percentage is roughly the expected share of gas for which the state will take delivery, based on its royalty share (royalty gas) and the gas associated with state's production tax (tax gas).

[17] The Alberta to Chicago project is an option that will be decided by the sponsor group as a whole. Other alternatives include utilizing existing pipeline capacity made available by decline in existing sources, expansion of existing pipeline systems, or installation of other "new build" pipeline concepts.

The administration has determined that state ownership in the project is in the long term fiscal interest of the state. As demonstrated in Section 5.1 state participation improves the economics of the project to a point that the Alaska natural gas pipeline project becomes an economically competitive option in the project portfolios of the sponsors. Ownership of the project will provide a stable revenue stream from the return on the state's investment compared to the income from selling the gas. In addition, the ownership and alignment of interests between the state and the project sponsors will expedite construction of a natural gas pipeline and the associated benefits to the state.

3.2 Fiscal Terms of the Deal

The state's existing oil and gas fiscal structure is composed of several different revenue streams:

- A share of the produced oil and gas (royalty share) because the state is the owner of the subsurface estate (AS 38.05.135);
- A production tax on the value of the product at the point of production[18] (AS 43.55);
- Property taxes subject to a maximum of 20 mills, and shared between the state and municipalities if oil and gas properties are located in an incorporated area (AS 43.56);
- State corporate income tax (AS 43.20.072).

The oil and gas industry may also be subject to municipal sales and use taxes, special assessments, and other charges.

Under the proposed fiscal terms, the state will receive these same major types of revenue streams with some modifications, particularly in the mode of payment. The contract terms provide for three types of payments: 1) gas payments; 2) cash payments based on volume of gas (volumetric); and 3) cash payments based on net income or profits (profit-based). Table 4 describes the existing and the proposed fiscal terms under each major type of revenue.

[18] The nominal oil production tax is 12.25 percent for the first five years of field production and 15 percent thereafter, with a minimum tax of 80 cents per taxable barrel (not including royalty oil produced). For natural gas, the nominal tax rate is 10 percent of its value at the point of production with a minimum tax of 6.4 cents per thousand cubic feet. The effective tax rate for both oil and gas is determined by multiplying the nominal tax rate by an economic limit factor (ELF).

Table 4. Existing and Proposed Fiscal Terms by Major Revenue Streams

Major Revenue Streams	Existing Terms	Proposed Terms
Royalty payments for gas	Option to take payments in-kind or in-value (minimum of 12.5 percent royalty share)	*Royalty gas* (taken as gas not cash; no change in royalty share)
Production tax payments for gas	Severance tax payments in cash (severance tax rate of 10% reduced by ELF to an average effective rate of about 7.25%)	*Tax gas* (cash value converted to gas; 7.25% with no ELF-adjustment)
Property tax payments	Properties to be taxed subject to max of 20 mills, to be paid in cash	*Upstream* and *Midstream* payments based on volume of gas
State Corporate Income Tax Payments	Cash payments based on federal taxable income with Alaska adjustments; max rate of 9.4% for taxable income greater than $90,000	*Payments in lieu of SCIT* based on net income; generally the same rate but with some modifications

Part D (Articles 11 through 25) of the contract comprises the agreed-upon fiscal terms; these articles discuss payment of fiscal obligations, define several types of payments in lieu of taxes, and include topics regarding measurement and reporting. Table 5 provides information on Articles 11 through 25; and where appropriate, the table relates these articles to elements of the existing tax structure in place in 2005 that they are meant to replace.

Table 5. Contract Fiscal Terms

Contract Fiscal Terms	Existing Fiscal Terms/Description of Term
Fiscal stability (Article 11)	Provisions for enabling fiscal certainty
Royalty payments (Article 12)	Royalty obligation in kind or in value
Tax bearing gas payment (Article 13)	Severance or production tax
Payments in lieu of production taxes (Article 14)	Still being negotiated (subject to oil negotiations)
Upstream facilities payments (Article 15)	Property taxes on oil field infrastructure
Midstream payment (Article 16)	Property taxes on gas infrastructure
Payments in lieu of oil pipeline ad valorem taxes (Article 17)	Property taxes on oil pipeline
Impact payments (Article 18)	Property taxes on project before commencement of commercial operations
Payment in lieu of SCIT (Article 19)	Production payment and upstream cost allowance not included
Upstream cost allowance (Article 20)	Reimbursement for field handling, gas transportation and treatment
Payments to political subdivisions (Article 21)	Local shared tax payment on oil, gas, and pipeline infrastructure
Payment of fiscal obligations (Article 22)	Procedures for tax and other payments
Point Thomson (Article 23)	Development of Point Thomson Unit
Measurement (Article 24)	Methods for determining amounts subject to fiscal provisions
Audit (Article 25)	Methods to verify satisfaction of obligations

The following subsections address Articles 11 through 25 in more detail.

3.2.1 Article 11 – Fiscal Stability

The Alaska natural gas pipeline project will be the highest capital cost private project ever proposed to be constructed in North America or the world. In enacting the SGDA, the legislature recognized that it could help facilitate development of the gas pipeline and encourage the significant benefits that result by providing a stable and certain fiscal environment. Such a fiscal environment is important for a number of reasons. First and foremost is the enormous cost to design and construct the pipeline and the fact that these expenditures occur early in the life of the project. That is, the developers of the pipeline must spend billions of dollars in advance of any gas flowing through the pipeline. Their investment will be recovered over an extended number of years. Providing certainty that the state will not change the "economic rules" in midstream encourages investment by providing assurances that the assumptions made during planning and construction regarding the project and the sponsor group's fiscal obligations to the state will continue to be true over the term of the contract. Similarly, just as fiscal certainty and stability can help foster the development of the gas pipeline, they also are important to encourage additional exploration for the reserves that are needed to fill the pipeline over the term of the contract. Like the pipeline, exploration on the North Slope often requires a producer to make a large up-front capital investment that is recovered through future production. Providing fiscal certainty with respect to taxes and royalty can help promote the additional exploration that is the underpinning for the development of the gas pipeline project.

To address fiscal stability, the state had to determine the taxes or potential taxes that could affect the project, define those taxes in contractual terms, and negotiate substantive and procedural limitations. Article 11 sets forth the bargain between the state and the sponsor group. In return for the performance of their obligations under the contract, such as work commitments, the monetary payments of Articles 11 through 19, and Article 22, capacity management, special expansion rights, state ownership, the opportunity to serve in-state needs, Alaska hire and Alaska business opportunities, the state covenants to provide fiscal certainty as laid out in the contract articles—consistent with Article IX of the Alaska Constitution. Article 11 also spells out the mechanisms by which the covenant can be enforced.

Section 11.1 of the contract sets out a covenant in which the state agrees to provide fiscal stability either by contracting away for a limited period its power to impose or change certain taxes, or by agreeing to reimburse a producer if certain kinds of tax changes occur. Sections 11.2 through 11.12 of the contract provide additional detail regarding the mechanics of implementing this agreement.

There are several categories of existing, future, or potential taxes:

1. *Restricted Taxes* cover a wide range of taxes on various aspects of the oil and gas business. Restricted taxes include property taxes on the project prior to commercial operations. Under existing law, political subdivisions are not allowed to impose these taxes and the contract continues that prohibition.
2. *Fixed Payable Taxes* are property taxes levied on certain non-project oil and gas assets (i.e., trucks or oil and gas properties located elsewhere in Alaska [non-ANS]).

The effects of these taxes are held constant under the contract so that if the law changes to raise taxes during the term of the contract, the state will reimburse the participants, and if the law changes to lower taxes, the participants will reimburse the state.

3. *Reimbursable Property Taxes* are existing property taxes that would affect the project, and when imposed by a political subdivision, the state will reimburse the payer.
4. *Targeted and Capped Taxes* are general taxes like sales or excise taxes—except for a tax that is enacted or changed after October 11, 2005—for which the participants, their affiliates, contractors, and subcontractors bear more than 20 percent of the tax burden, which is then defined as a Targeted Tax.
5. *Other Tax* is a tax levied by a political subdivision that does not fit any of the above categories.

For taxes levied by the state, the participants will pay 1) *fixed payable taxes;* and *2) capped taxes* up to the fiscal stability cap of $4 million per year before commencement of commercial operations and $5 million each year thereafter, escalated using the CPI with a 2005 base year; and will either pay or receive a fiscal stability increment[19]. Each participant would be exempt from all other state taxes, and may generally exercise its exemption by withholding payment. State taxes will be audited under the contract and any disputes will be resolved under the contract terms.

For taxes levied by political subdivisions, each participant is obligated to pay all but restricted taxes, and *other taxes* (as that term is defined) in excess of $10 million a year. With those two exceptions, even if the participant is exempt from a tax, such as a reimbursable property tax, targeted tax, or a capped tax above the fiscal stability cap, the participant will pay it, and then will be reimbursed by the state.

This article also sets out the rules under which a participant gets to audit taxing authorities to see if a tax is a *targeted tax*, identifies the circumstances where a participant is indifferent to the amount of a tax because the state will reimburse it for taxes paid, and identifies the procedure for the state to appeal and participate in disputes with the political subdivision regarding a tax on a participant.

3.2.2 Article 12 - Royalty Payments

The State of Alaska typically has a royalty interest of 12.5 percent or greater of the produced oil and gas on the North Slope, although sliding-scale royalties[20] and net profit share provisions exist on some leases. This royalty interest remains at the same rate in the proposed contract.

Under existing North Slope oil and gas leases, the state can physically take the oil and gas and market the products, sell the oil and gas to other parties at market prices, or allow the

[19] The fiscal stability increment refers to the change in tax due to a change in law.

[20] A sliding-scale royalty is a leasing method which involves computing the royalty share based on a sliding scale according to the volume of production or other factors which in no event may be less than 12.5 percent in amount or value of the production removed from the lease.

producers to sell the products and pay the state a royalty based on the wellhead value after deduction of certain transportation costs.

Article 12 of the contract provides that prior to the commencement of commercial operations,[21] the state will receive its royalty as provided in the applicable lease or other agreements in effect on October 1, 2005.

After commencement of commercial operations, the state will take physical delivery of its royalty gas from individual producers at a delivery point. The total volume of royalty gas due to the state is based on the royalty percentage for the applicable lease, unit, or settlement agreement, and the total volume of gas subject to royalty. On leases where sliding scale royalty provisions are applicable, the producer can elect to convert to a fixed royalty percentage for the term of the contract.

The state will assume responsibility for field handling costs and other costs, including disposition of carbon dioxide and other impurities, as described in Article 20, which discusses cost allowances.

3.2.3 Article 13 – Tax Bearing Gas Payment (Tax Gas)

Article 13 describes a payment that would replace the severance or production tax on gas that exists in the current fiscal structure. The contract uses the term “Tax Bearing Gas Payment,” but for simplicity the term “tax gas” is used in this discussion.

Under current law (AS 43.55), the production tax for gas is calculated as 10 percent of the gross value of the taxable gas produced from the property, or $0.064 per mcf of taxable gas produced from the property, whichever is greater, and as modified by the ELF. This tax will remain in effect under the contract until the GTP, the mainline, or an NGL plant in Alaska is available.

Gas that is subject to the production payment (tax gas) under the contract does not include:

- State royalty gas;
- Gas produced from federal leases on the Outer Continental Shelf;
- Gas equal to the royalty from private and federal leases in Alaska.

During line pack[22], which occurs right before commencement of commercial operations, the state will receive cash proceeds based on the total proceeds received by the producer for the volume of tax gas from the property, multiplied by the production payment percentage.

After commencement of commercial operations, the state will receive its payment as a share of each producer’s tax gas in lieu of receiving a cash payment, with delivery at the lease

[21] When the pipeline is being filled with gas before the start of commercial operations, the state will receive cash proceeds based on the total proceeds received by the producer (for the gas) multiplied by the royalty percentage for the property. The Mainline Entity (LLC) will purchase gas from the owners to fill the pipeline before the start of operations.

[22] Line pack refers to the quantity of gas purchased for operational (non-commercial) use by the mainline entity to fill and pressurize the pipeline prior to the commencement of commercial operations. The line pack quantity is considered a permanent part of the pipeline's asset base (and its cost is included in the tariff), allowing the pipeline to deliver gas for a shipper at a pipeline delivery point at the same time the shipper delivers that quantity of gas to a pipeline receipt point.

boundary. The production payment percentage is 7.25 percent of the gas after subtraction of royalty gas.

On state-owned lands, the effect of the contract's tax and royalty provision will result in the state receiving slightly less than 20 percent of the total gas produced. The amount of gas received by the state is expected to decline as gas from federal lands subject to federal royalties is developed and becomes a larger share of the gas shipped through the mainline.

3.2.4 Article 14 – Payments In Lieu of Production Taxes

Article 14 is still being negotiated.

3.2.5 Article 15 – Upstream Facilities Payments

The Upstream Facilities Payments[23] have two components, an oil payment and a gas payment. These payments are paid by the producers who have interests in facilities upstream of a delivery point. The oil payment is an annual payment that replaces property and other taxes on the ANS oil field infrastructure of the producers who are party to the contract. The upstream facilities oil payment provides additional fiscal certainty for the producers on their ANS oil infrastructure that typically produces both oil and gas.

The upstream oil payment is based on the volume of hydrocarbon liquids—including royalty volumes—delivered from a property to a common carrier pipeline and eventually to TAPS. This volume of oil is multiplied by a payment for each barrel. The payment per barrel varies between fields based on the current property tax assessment as shown below:

- $0.496 per Barrel for Prudhoe Bay Unit;
- $0.500 per Barrel for Point Thomson Unit;
- $0.482 per Barrel for Kuparuk River Unit;
- $0.579 per Barrel for Duck Island Unit;
- $_____ per Barrel for Northstar Unit;
- $0.579 per Barrel for Milne Point Unit;
- $0.452 per Barrel for Colville River Unit;
- $0.579 per Barrel for Badami Unit;
- $0.500 per Barrel for a Property existing on January 1, 2005, but not included in the above Properties on January 1, 2005; and
- $0.500 per Barrel for a Property added under Article 31.

For oil fields producing as of the date when the contract is fully executed, the annual volume is estimated as the average of the actual annual volumes produced during the preceding five calendar years, if a payment is due in 2006 or 2007, and an average of the actual annual volumes produced during the preceding three calendar years for payments due in subsequent years. For the first five years of production for new fields, the volume is based on the actual

[23] The upstream payment does not replace property and other taxes that are currently levied against the TAPS.

annual volume delivered to an oil pipeline during the prior-year, and for each year thereafter, an average of the annual volumes produced during the three prior calendar years. The payments per barrel shown above are adjusted annually beginning in 2007 at 70 percent of the annual change in the Consumer Price Index (CPI).

The upstream facilities gas payment is applicable for the volume of producer gas, associated state gas, and other royalty gas from a producer's property, measured at the delivery point, multiplied by $0.021 per mcf. After the fifth year of production, the volume of gas is an annual arithmetic average of the prior three calendar years. The gas payment shown above is adjusted annually at 80 percent of the annual change in CPI.

3.2.6 Article 16 - Midstream Payment

The Midstream Payment is an annual payment by the entities (including the state) that own the mainline, gas transmission lines, and GTP designed to replace property and other taxes that might otherwise be levied on the midstream elements of the mainline, the GTP, and any gas transmission pipelines. The following are the terms agreed upon:

- The midstream payment for gas entering the Mainline is $0.024 per mmBtu;
- The midstream payment for gas flowing from the GTP into the Mainline is $0.01 per mmBtu; and
- The midstream payment for gas flowing on other gas transmission lines—lines that are upstream of either the GTP or the Mainline—are based on $0.0003 per mcf per mile that the volume of gas is transported in the gas transmission line.

The quantity or volume of gas for the first five annual midstream payments is based on the prior year's quantities or volume, and for each subsequent year will be based on an average of the prior three years.

The dollar per mmBtu and dollar per mcf per mile rates noted above are adjusted annually for inflation based on the full CPI inflation adjustment using 2005 as the base year. The parties will negotiate an appropriate midstream payment rate for any new midstream element facilities that are not covered in the contract.

3.2.7 Article 17 – Payments In Lieu of Oil Pipeline Ad Valorem Taxes

Article 17 provides for payments in lieu of oil pipeline ad valorem taxes for the producers that are parties to the contract and that have interests in oil pipelines on the North Slope. In general the sponsors will continue to make payments that are equivalent to the 2006 payments made under the existing statutes, and inflated over time.

3.2.8 Article 18 - Impact Payments

Under the existing fiscal structure (2005 fiscal terms), communities that would be affected by the project could levy property taxes on the pipeline while the project was under construction and those new property tax receipts could be used to address potential impacts to the community. Under the proposed contract terms, local municipalities will be compensated with Impact Payments (payments that address local economic and social impacts in communities that may be economically affected by the project as required under AS

43.82.505) but the ability to tax the project, even during construction is limited by the contract.

The impact payments cited in the contract total $125 million and will be paid over a six-year period. The first payment would occur at the end of the calendar year immediately following project sanction. If any of the impact payments occur nine years after the effective date, those payments will be adjusted for inflation using the CPI for the ninth year as the base. The annual payment schedule is shown in Section 4.1.

3.2.9 Article 19 – Payment In Lieu of State Corporate Income Tax (SCIT)

Article 19 establishes the rules for payments in lieu of the state corporate income tax (SCIT) for the producers that are party to the contract. In general, producers will continue to make payments that are equivalent to the SCIT in accordance with existing state statutes and codes. The exceptions are that the gas delivered to the state under Article 13 (tax bearing gas payment), the cost allowances (Article 20), and the field cost allowance (Article 19.4) paid by the state to the producers under leases or other agreements, will not be included as sales in calculating SCIT. The article also clarifies the process to be used if the federal income tax system changes and acknowledges that the SCIT payment is a tax based on, or measured by, net income.

3.2.10 Article 20 – Cost Allowances

Under some leases and agreements, the state production tax regulations allow a similar deduction against production taxes levied on produced gas. Under current practice, the state pays the oil producers a fee to cover the cost of handling, treating, and transporting the state's royalty gas from certain leases. Article 20 establishes contract terms for similar activities related to the state's gas received per the contract.

The 1980 Prudhoe Bay Unit (PBU) Royalty Settlement Agreement provided for the state to compensate the PBU leaseholders for certain costs the leaseholders incurred in handling and treating state royalty oil and gas. The provisions of Article 20 of the contract, as described below, supersede and replace those portions of the PBU agreement related to gas. The provisions of Article 20 also apply to other gas that is subject to Upstream Facilities Payments, only after a major gas sale.

Under Article 20, the state agrees to pay an upstream cost allowance (UCA) for field handling costs, transportation to the delivery point (i.e., the GTP or Mainline), and treatment of the state's royalty and tax gas. The UCA covers direct and indirect costs associated with gathering, separating, cleaning, dehydrating, compressing, and other field handling costs upstream of a delivery point. The UCA is set at $0.224 per mcf on state gas, including volumes of any impurities that are reinjected, and is paid on a monthly basis. This UCA rate is adjusted annually for inflation according to the CPI indexed to 2005.

Cost allowances for royalty oil or NGLs under existing lease or other agreements will remain in place.

3.2.11 Article 21 - Payments to Political Subdivisions

Article 21 provides for payment to local political subdivisions (e.g., the North Slope Borough, Fairbanks North Star Borough, and any new political subdivision that may be formed) to replace property and other taxes that might be levied by these political subdivisions on the project or the producers.

The contract describes the method to be used for calculating the amounts due to each local government for upstream facilities payments, midstream payment, and oil pipelines (Articles 15, 16, and 17). These payments will be made by the pipeline and GTP owners (including the state). The portion of the payments not going to the political subdivisions will go to the state. Political subdivisions will receive their payments in proportion to the relative amount of the asset within their borders, and proportional to their mill rate divided by 20. In addition, for the mainline, the payments to the North Slope Borough and the Fairbanks North Star Borough are proportional to the mileage of the pipeline contained within their jurisdictions relative to a total mileage of 450. The use of 450 miles in the calculation both preserves status quo revenues for the political subdivisions and allows for expansion. In the event new political subdivisions form, amounts not otherwise allocated to the two existing boroughs may be reallocated to the new political subdivisions, rather than to the state.

3.2.12 Article 22 – Payment of Fiscal Obligations

Article 22 describes the procedures under which beneficiaries of the contract will make payments to the state every month, including mechanisms for the beneficiaries to insure collection of certain amounts the state may owe in the unlikely event that such amounts were owed and the state did not pay them on a timely basis (e.g., during a period of very low prices the beneficiaries may have low SCIT PILT and PPT PILT payment obligations, or the political subdivisions might impose taxes that the state is obligated to reimburse under the contract). In such event, the payment procedures set forth in this Article will under certain circumstances: (i) allow each producer to seek repayment of amounts that may be owed to it or its affiliates by the state either by receiving redirected payments under state gas sales contracts or by recovering the amount by recouping the value from the sale of gas it would otherwise deliver to the state, and (ii) subject to the rights of the state’s lenders under certain project indebtedness, allow each midstream entity to offset amounts that may be owed to it by the state by against distributions that such entity might otherwise pay with respect to the state’s equity interest.

There are two payment procedures described in Article 22. The first (Article 22.1) applies to the producers and their affiliates and the state, and the second (Article 22.2) applies to each midstream entity and the state. In the producer/affiliate payment procedure, a producer adds up all the payments under the contract that the producer and its affiliates collectively owe to the state in a month, and then subtracts the payments owed to them by the state under the contract. If the amount is positive, the producer must pay the net amount to the state. If the amount is negative, the state actually owes the producer the net amount. The state may pay the amount immediately or may elect to defer payment for up to three months in anticipation that during that three-month period the net obligations owed to the state by the producer/affiliate group would ultimately offset the amount owed to the producer by the state (for example, as a result of an estimated quarterly SCIT PILT payment obligation becoming due). If, after three months, the state’s obligation has not been offset by additional net payment obligations of the producer/affiliate group, then, subject to certain restrictions, the producer may withhold the state's share of the gas that the producer would otherwise provide the state under the contract (excluding the royalty portion from which proceeds are dedicated to the Permanent Fund) and use the proceeds from the sale of that gas to recoup the amount the state owes (including accrued interest). A producer may also assign its right to any payments from the state under Article 22 to another producer or to a midstream entity, which would then be included in the calculation of the assignee's obligations under Article 22.

The second payment procedure is parallel to the producer procedure described above except that it deals with payment obligations between each midstream entity and the state under the contract. In this payment procedure, if the state has a net payment obligation to a midstream entity owner which has not been paid by the state within three months, then the midstream entity may, subject to certain restrictions, withhold payments (such as dividends or periodic distributions) that that midstream entity would otherwise owe to the state until the state's payment obligation is paid in full.

It should be noted that any payment under the contract between the producers, the state, and the owners of the midstream elements will be offset against one another during each month. For this purpose the SCIT PILT—and for a period of thirty years—the PILTS replacing the PPT and ad valorem taxes on oil pipelines, are pertinent components of the payment procedures. However, payments to political subdivisions must be made by the producers, their affiliates, and the midstream entities directly to the political subdivisions, and will be netted out for purposes of the calculations in Article 22.

3.2.13 Article 23 – Point Thomson

Article 23 addresses development of the Point Thomson Unit (PTU). The PTU has not yet been developed, but is critical to the success of the project because it contains about 8 tcf of natural gas—that is, 23 percent of the total recoverable known gas reserves in the North Slope that are anticipated to be dedicated to the project. This article commits the PTU producers to produce a minimum of 500 million cubic feet per day of PTU gas for the project. The producers shall apply to the Alaska Oil and Gas Conservation Commission for issuance of pool rules to authorize the field gas off-take rate for PTU gas within six months of the effective date of the contract.

Under the contract, the state agrees to (i) temporarily suspend any enforcement actions with respect to the PTU, (ii) suspend any actions to terminate the PTU, (iii) forbear from requiring the PTU owners to prepare and obtain approval of a plan of development for the PTU, and (iv) forbear from requiring that the PTU owners alter or modify the rate of development or operations of the PTU. The suspension would last until the date of initial delivery of PTU gas into the gas line. Within nine months of that date the PTU owners will then be required to submit a plan of development for the PTU.

If the contract is terminated or the producers fail to satisfy their obligations under the contract, the state will have the option to terminate the temporary suspension, in which case the PTU owners must (1) begin development drilling in the PTU within one year after the termination of the suspension period; (2) drill seven development wells in the PTU within three years after the termination of the suspension period; and (3) submit a plan of development in order to retain the PTU leases.

3.2.14 Article 24 – Measurement

Article 24 addresses the issue of measuring volume, quantity, and composition of gas and hydrocarbon liquids. Measurements used to account between the participants and the state are to be the same as measurements used to account among the producers. Measurements shall be provided by the entity owning the asset, or other person responsible for making the measurements. Gas delivered to the state must have the same composition as gas delivered to the producers at the delivery point (lease boundary).

3.2.15 Article 25 – Audit

Article 25 covers audits under the contract. Within the time and procedural constraints of this article, the state retains the right to audit as necessary to verify a participant's fiscal obligations under the contract. Depending on the scope of the audit, the audit period is restricted to two to three years. Most of the article focuses on audits of the SCIT PILT, including (i) what to do if the IRS no longer views the SCIT PILT as a tax, (ii) how to handle IRS adjustments to federal returns that affect state returns, and (iii) a requirement for the state to show good cause before it audits certain items also subject to audit by the IRS or for certain categories of foreign income subject to audit by the participants financial auditors.

3.3 Alaska Hire and Content

If the project goes forward, a significant number of new jobs will be created during the construction period, and a smaller but substantial number of permanent jobs will be needed to operate the mainline and other project components during the operational period. In order to ensure that a large proportion of these new positions—especially during construction peaks—can be filled with Alaska residents, Article 6 of the contract includes several terms that would enhance Alaska employment and content.

In accordance with the SGDA, the contract requires compliance with laws relating to hiring of Alaska residents or contracting with Alaska businesses and the training of employees responsible for making hiring and contracting decisions on these requirements. Within the constraints of law, each midstream entity shall employ Alaska residents and shall contract with Alaska businesses to work on construction, fabrication, or operation of the Alaska project to the extent Alaska residents or Alaska businesses:

- Are available, ready, willing and able to accept employment at the time required and are located anywhere in Alaska, not just in the area of Alaska where the work is to be performed;
- Are competitively priced in that they offer goods or services required by an Alaska project entity at a total cost that is equal to or less than the total cost of equivalent goods or services offered by a non-Alaska resident or a non-Alaska business; and
- Possess the requisite resources, education, training, skills, certification and experience to satisfactorily perform the work necessary for a particular position or to perform a particular service.

When hiring employees, the contract requires the midstream entity to advertise for available positions and use Alaska Job Service Organizations (the Alaska Job Center Network) to notify Alaska residents of available positions and provide the Alaska Department of Labor and Workforce Development (Labor Department) with a copy of each advertisement at the time each advertisement is made public.

To ensure that contractors working on the Alaska project comply with the labor provisions of the contract, the contract (See Figure 14) provides specific language to be included in contracts for the provision of goods or services in connection with the Alaska project.

Figure 14. Contract for Alaska Hire and Content

1. Comply with law. [Contractor Name] shall comply with all valid laws relating to hiring of Alaska residents or contracting with Alaska businesses to work on construction or operation of the Alaska project. In making hiring or contracting decisions for construction or operation of the Alaska project, [Contractor Name] shall not discriminate against Alaska residents or Alaska businesses.

2. Alaska Hire. Within the constraints of law, [Contractor Name] shall employ Alaska residents and shall contract with Alaska businesses to work on construction, fabrication, or operation of the Alaska project to the extent Alaska residents or Alaska businesses:

a. are available, ready, willing and able to accept employment at the time required and are located anywhere in Alaska, not just in the area of Alaska where the work is to be performed;

b. are competitively priced in that they offer goods or services required by an Alaska project entity at a total cost that is equal to or less than the total cost of equivalent goods or services offered by a non-Alaska resident or a non-Alaska business; and

c. possess the requisite resources, education, training, skills, certification and experience to satisfactorily perform the work necessary for a particular position or to perform a particular service.

3. Recruitment. In hiring its employees, [Contractor Name] shall advertise for available positions and use Alaska Job Service organizations to notify Alaska residents of available positions on the Alaska project, under the requirements of the SGDA. [Contractor Name] shall provide the State of Alaska Department of Labor and Workforce Development ("Labor Department") with a copy of each advertisement at the time each advertisement is made public. The Labor Department may publicly disseminate that information. A position is available if:

a. it is vacant and located primarily or exclusively in Alaska;

b. it has not been offered; and

c. [Contractor Name] intends to fill it with personnel not already employed by [Contractor Name] or its affiliate.

4. Reporting. The state shall report Alaska resident employment on the Alaska project, consistent with the provisions of applicable law. [Contractor Name] shall facilitate this reporting by using the state electronic unemployment insurance.

The owners of the pipeline and their subcontractors will recruit and employ Alaska residents and contract with Alaska businesses. In order to maximize opportunities for local hire and to reduce impacts of population growth due to immigration, workforce development efforts in Alaska communities will require an estimated $6.6 million in new training costs over the four years prior to, and at the beginning of the project to meet gas pipeline construction needs. (Information Insights, Inc., 2004)

The contract requires the mainline entity to spend or cause the spending of a combined total of $5 million in funding workforce training programs and activities in Alaska. (ADOL&WD, 2005b) Other sources of funds that can support training for skills that will be needed to construct and operate the proposed pipeline include $7.5 million in grants awarded to the Alaska Department of Labor and Workforce Development (Labor Department) from the U.S. Department of Labor for pipeline training and for the high growth energy initiative plus up to $5 million per year from the Alaska Training and Employment Program, which is given priority for energy-related workforce development. (ADOL&WD, 2005b) The emphasis on recruitment and training of Alaska residents for pipeline construction and operation jobs is a direct result of lessons learned during the construction of TAPS.

3.4 Capacity Management

The purposes of the Capacity Management article (Article 10) are to ensure:

1) State gas can always be transported from the point of delivery to the market, along with the producer gas with which it is associated;
2) The state does not bear unreasonable risks or costs due to holding commitments to long term capacity, disproportionate to expected production shares;
3) The state marketing entity receives production, forecast and other information required to effectively manage capacity commitments and marketing;
4) While accomplishing 1) – 3), above, the state maintains the ability to meet North Slope and other instate gas demands.

Article 10 consists of seven key sections:

1) *Open season capacity acquisition*

Article 10.1 provides for the state to receive a proportionate share of firm capacity obtained in an open season, by producer and property, based on the expected share of state gas from that producer and property. The producer obtains firm capacity on behalf of the state "to the extent the *producer capacity holder*[24] is successful in obtaining capacity". The article does not contemplate that firm capacity will be initially assigned in any manner other than in an initial open season or subsequent open season. The state and producers may seek FERC approval of the capacity management article to mitigate risks of future regulatory shifts. In addition, the article specifies that if the state were to obtain capacity in any manner outside the terms of this article, the producer commitments to obtain capacity on behalf of the state would terminate.

[24] This term as used in the fiscal contract means an affiliate of a producer that holds or will hold capacity on behalf of that producer. The term "producer" in this definition refers to BP, CP, or EM.

Under the terms of Article 10.1, the state is also able to meet North Slope and other in-state gas demands. These demands and capacity requirements must be determined by the state prior to an open season, and will be included in open season bidding. The article also allows the state to choose to acquire firm capacity directly at an open season; however, if the state chooses to do so, all producer commitments to acquire firm capacity on behalf of the state terminate.

2) *Insufficient state capacity*

Article 10.2 is intended to ensure the state always obtains the capacity to move state gas to market along with, and under similar terms as, the producer gas with which it is associated. If a producer is planning deliveries for which the state has inadequate capacity, the producer is required to "satisfy any need for capacity required by the state to transport or treat additional state gas from that property". The producer retains the right to choose various alternatives to meet the state's need including:

1) Re-designating unused firm capacity to the property and reallocating the re-designated capacity between the producer and the state (Art. 10.2(a)(i));
2) Releasing firm capacity to the state (Art. 10.2(a)(ii));
3) Acquiring firm capacity and releasing a portion to the state (Art. 10.2(a)(iii)):
4) Acquiring capacity on the state's behalf directly (Art. 10.2(a)(iv)); or
5) Performing other actions to meet the state's need as may be mutually agreed (Art. 10.2(a)(v)).

If the actions in 1 – 5 cannot eliminate the state's shortage, the producer may purchase the state gas at the market gas price minus netback, or reduce deliveries to the project. The actions taken by a producer are also constrained by several provisions:

- State capacity must be adequate to transport and treat associated state gas delivered by the producer to the state (Art. 10.2(a)).
- The producer-initiated capacity re-designation must ensure the state's firm capacity share for that producer and property equals the Forecast Ratio for that property (Art. 10.2(a)(i)).
- Capacity released to the state or obtained for the state must be under the same terms and conditions as capacity obtained by the producer on their own behalf (Art. 10.2(a)(iii)(A) and (B)).

Article 10.2(a)(ii) [action 2, above] can be implemented in a scenario in which a producer has a relatively high proportion of the total unused firm capacity commitments, with respect to other producers. As a result, a relatively high proportion of the state's unused firm capacity is associated with that producer. If, subsequently, the producer delivers gas to the project from a property with a higher forecast ratio than which was assumed in the existing unused capacity shares, the state may then not have adequate capacity to transport and treat the state gas associated with that producer's new deliveries. In such a situation, it will be necessary for the producer to release capacity to the state to provide the state capacity to transport and treat state gas delivered by that producer from that property. This would be implemented by exchange of notices in accordance with Article 10.2(b). The notice from the producer releasing capacity to the state provides final documentation of the capacity resolution.

Article 10.2(a)(ii), as well as all other actions which may be undertaken by a producer under Article 10.2(a), may only be implemented if the state has inadequate state capacity. After resolution by one of the actions under Article 10.2(a), except item (ii), the producer will issue a final capacity notice to the state (Art. 10.2(c) or Art. 10.6) to document the final capacity resolution.

3) *Excess state capacity*

Article 10.3 seeks to maintain parity between a producer and the state with respect to utilizing excess firm capacity commitments. The state has a proportional right to participate in transactions to acquire unaffiliated gas purchases initiated by a producer to fill excess firm capacity and to release excess firm capacity to the extent of the Takeaway Ratio between the state and that producer. In both cases, the terms received by the state must be the same as those received by the producer.

Rejection by the state of an offer made under Article 10.3(c), will destroy the proportionality between state and producer firm capacity commitments, and terminate all future producer obligations under the capacity management article.

4) *Put capacity*

Above a minimum threshold of imbalance (Art. 10.4(d) (iii)), Article 10.4 provides the state and a producer the mutual right to “put” firm capacity commitments to the other, if the entity bears a disproportionate share of firm capacity commitments. This section will protect the state in the scenario in which deliveries are inadequate to keep the pipeline full and exploration, development, and production efforts have moved away from state acreage (where the state gas share is around 20 percent) to non-state acreage (where the state gas share is 0 to 7.5 percent). If the state’s Takeaway Ratio exceeds the state’s Forecast Ratio, the state may “put” excess firm capacity commitments to the producer to equalize the Forecast Ratio to the Takeaway Ratio. These “puts” are done month-to-month at the Effective Rate for that firm capacity. Were the relationship between the Takeaway Ratio and the Forecast Ratio to be reversed, the producer would then have a similar right to “put” firm capacity to the state to restore the equality.

If a producer shifts production deliveries from one property to another, the producer is required to re-designate, in a Capacity Notice (Art. 10.2(a) & (c)), the firm capacity upon which it is shipping, to the new property. If the producer’s Forecast Ratio also changes due to production from a property being increased above the volumes specified in an existing Capacity Notice, firm capacity upon which the production is being transported or treated must be released and acquired to match the Takeaway Ratio to the new Forecast Ratio for the term of those deliveries (Art. 10.4(d)).

5) *Short-term imbalances*

Article 10.5 states that minor and temporary field imbalances (less than a month) are not covered by the Capacity Management article, but by gas balancing agreements among the producers. The producers are required by Article 10.5 to extend the terms of any gas balancing agreements to the state. Article 10.5 also describes other tools the state may use to manage minor and temporary field imbalances.

6) *Other amended capacity notices*

Article 10.6 is intended to require a producer to submit to the state an amended capacity notice within 90 days after any change which would change the current capacity notice.

7) *Information*

Article 10.7 requires that, to the extent a producer receives information; the producer shall promptly provide the state with information on deliveries and forecasts. The standard for information the producer is responsible to transmit to the state under this section is the completeness, applicability and immediacy of the information received.

The seven key sections are followed by four administrative sections which largely provide constraints on legal and arbitrated commitments under the terms of the article:

- Term and termination—which provides for producer commitments under this article to terminate if the state takes action, or fails to act, creating an imbalance between state and producer capacity commitments; or if a judicial authority invalidates the provisions of the article and if the parties are unable to develop an alternative to the invalidated provisions. The state's unilateral right to terminate is also defined.
- Limitations on remedies and damages—specifies that damages awarded with respect to terms of this article are limited to specific performance under the article.
- Indemnification—specifies that the state indemnifies the producers for damages incurred as a result of implementing the terms of this article.
- Compliance with law—provides that the producers and state will adhere to FERC Standard of Conduct in performing under the terms of this Contract.

Capacity management is implemented with the use of Notices and Capacity Notices between the state and each shipping producer as defined under the contract. Separate capacity commitments will need to be managed for firm capacity offered on each element in the transportation and treatment system:

- Each transportation pipeline from a delivery point to the GTP, mainline, or an intermediate transportation pipeline;
- The GTP will offer unbundled services, requiring capacity in each section of the GTP to be managed separately;
- The mainline within Alaska, including in-state deliveries;
- The mainline within Canada to the point(s) of delivery to take-away points; and
- Depending on the ultimate scope of the project, capacity may need to be managed in a lower-48 states segment of the mainline.

It will be necessary for each shipper, including the state, to manage and integrate these separate and distinct capacity commitments in order to efficiently manage shipments upon the system. The state and sponsor group may seek early FERC approval or acceptance of these capacity management procedures in order to reduce the risk that they might be invalidated by subsequent actions or policy shifts. Similar approval by NEB may also be sought for the Canadian portions of the project.

3.5 Work Commitments

Under Article 5 of the contract, the participants will be required to advance the project "as diligently as is prudent under the circumstances" until project sanction.[25] This performance standard is defined in the contract as "diligence."

The three planning-related requirements that the participants have committed to under Article 5 are

- project implementation,
- preparation of a qualified project plan, and
- preparation of an annual project summary.

The project implementation obligation requires that the participants begin project planning no later than 90 days after the effective date of the contract, and after that point, they must advance planning with diligence and conclude with a decision whether to begin regulatory applications and open season planning. The qualified project plan is a plan that will be prepared by the mainline entity on behalf of the participants that will outline how the project will be implemented. The plan will be prepared, amended, and submitted to the state annually until the commencement of commercial operations. Included with the qualified project plan will be a project summary, which will contain a project overview, a description of the work accomplished, an estimated project schedule and proposed development activities, and a description of expenditures and programs implemented under the Alaska workforce training and development programs described in Article 6.4 of the contract.

If the participants do not exercise diligence, the state's exclusive remedy is termination of the contract before project sanction. In order to terminate, the state must establish by clear and convincing evidence that the participants did not act with diligence, and that it resulted in a material adverse impact to the project. The state may initiate termination of the contract by providing a termination notice to all participants. The termination notice may be disputed by one or more participants, who may suspend their obligations in response, and who have the opportunity to cure.

If all participants consent to the termination notice, the contract will expire on the 60th day after the issuance of the notice. Any disputing participant must provide notice of the dispute to the state within 60 days of receipt of the notice. The dispute will be resolved under the mandatory dispute resolution procedures set forth in Article 26 of the contract, except the parties will not be required to exhaust the amicable resolution process, the Tribunal will only decide the issue of diligence under the clear and convincing evidence standard, and the decision may be made public.

Once the state issues a termination notice, the mainline entity may suspend its obligations, and, subsequently, any participant may suspend its obligations by providing a suspension

[25] Project sanction refers to the point when the state and the project sponsors collectively vote, as members of the entity that would build and operate the pipeline, to proceed or not proceed with the construction of the project. Prior to this collective decision, the state and the board of directors of each of the project sponsors would make independent decisions regarding their participation in the project entity and authorizations for expenditure of funds and the borrowing of money for that purpose. There are certain conditions required by the mainline entity before it proceeds with construction.

notice to the state and all other participants. However, suspension may not be invoked until the participant has the opportunity to address the deficiency. The participants have 90 days from the date of the notice to take any actions they deem appropriate to address matters. If the final resolution is to terminate the contract, the participants still may commence a cure within 60 days of the resolution. The participants must thereafter pursue the cure to completion, and the date for performance of any mainline entity and impacted participants' obligations will be extended by a period equal to the length of the suspension. The state may file a notice of dispute to contest the adequacy of the cure, but the participants will not have a second opportunity to cure after resolution.

The suspension notice will remain in effect until it is terminated by the mainline entity or the date of a final resolution of the dispute. While the suspension notice is in effect, each obligation identified in the suspension notice will be suspended, except for payments due under Articles 14, 15, 17 and 19. Each party will bear its own costs incurred in connection with a suspension, and no penalty or interest will accrue on amounts otherwise payable to the state by the mainline entity or the impacted participants. After the end of suspension, if the contract remains in effect, the time periods for obligations will be extended by an amount of time equal to the length of the suspension. If the contract is terminated, the mainline entity and the impacted participants will be free of further obligations under the contract except for the rights, privileges or obligations that accrued before the earlier of the effective date of the suspension notice (if there was one) or the date of the final resolution of the dispute.

If the contract terminates before completion of the initial open season for the mainline, the project entity agreements must allow the state's affiliate to dissolve the project entity. If the contract terminates after that open season, the state's affiliate may withdraw from each project entity.

These work commitments may be suspended upon the occurrence of certain other conditions as stipulated in Article 35 (*Force Majeure*[26]) or as a result of Canadian regulatory processes or Canadian aboriginal issues. Under Article 35, any party declaring f*orce majeure* shall provide prompt notification to other parties. All parties shall attempt to alleviate the f*orce majeure* condition. In the event of *force majeure*, obligations regarding payments, receipt of hydrocarbons and/or for handling treating and transporting hydrocarbons are suspended. The state may not claim *force majeure* due to laws or directives issued by the state or its political subdivisions. The types of events that are included in *force majeure* are identified in Article 35 of the contract.

The contract provides for the contingency that Canadian regulations or Canadian aboriginal rights might pose serious obstacles to completion of the project. In such a contingency, a party could suspend or terminate its work commitment obligations, subject to the decision of the Arbitration Tribunal as specified in Article 5 and certain exhibits of the contract.

The work commitments will be performed in conjunction with the step by step project process laid out in Section 8. The cost and design of the project will become more defined as the project is advanced through this step by step process—from the front end engineering and design, the open season, the FERC certificate and other agencies' permitting process, all the

[26] Generally defined as an act over which the party has no control (e.g., Acts of God, war, etc.) Work suspensions are also allowed during a judicial challenge to the fiscal contract and during certain disputes between the parties.

way to project sanction, What the sponsors have set forth as the project process corresponds to industry standards for the project life cycle (IPA Institute, 2005; Flybjery, et al, 2003). A staged project process helps mitigate that risk.

As the project advances through the stages of its development, the state through its membership in the to-be formed mainline entity (the Alaska Gas Pipeline Co. LLC [AGPC], see Section 8.2) will be a participant in the major decisions of project development. The state will form an entity, the Alaska Natural Gas Pipeline Corporation (ANGPC) that will own its membership interest in AGPC and will be entitled to appoint a member of the management committee of AGPC. The major decisions, including budget, will be reviewed and approved by that management committee. As such, ANGPC will have access to the budget, engineering and field reports, plans for securing regulatory approval, and the construction plan itself. A 20 percent share of the money being spent will be funded by the state through ANGPC so ANGPC will have every incentive to be vigilant and interested in the activities of the AGPC as it steps through the process. Unlike TAPS, the state's public corporation will be at the table, gaining information, speaking to the issues, and voting on a wide variety of critical matters.

3.6 In-State Markets

Article 9 of the contract describes the conditions for providing natural gas for in-state markets. Items covered by this article include in-state needs and off-take points[27], the open-season in-state service, the in-state distribution system, in-state gas sales contracts, and the completion of a feasibility study analyzing NGL processing opportunities in Alaska.

The contract allows the state to request up to four in-state off-take points and if requested by the state, the mainline entity would support funding of the construction of these off-take points. Article 9.1 establishes that at least 30 days before filing its plan for the initial open season, the mainline entity shall:

- Complete/adopt a study of gas consumption needs and off-take points consistent with FERC requirements; and
- Consult with the state on the location of the off-take points.

The rules issued by FERC governing the conduct of open seasons for Alaska natural gas pipeline projects require any open season notice to include an assessment of in-state needs based to the extent possible on any available study conducted by Alaska and a listing of prospective delivery points within Alaska. Ultimately, the selection of in-state off-take points would be guided by the study of natural gas consumption needs and prospective in-state off-take points.

Article 9.2 describes the open season in-state service. The mainline entity shall offer mileage-sensitive rates for gas transmission service to the off-take points designated in Article 9.1 during an open season. In addition, the mainline entity must propose tariff provisions for segmented capacity consistent with FERC procedures, so that a shipper may

[27] In the contract, "off-take point" means a connection, consisting of necessary valves, flanges and fittings, where gas flows out of a midstream element, except for a location where gas flows from one midstream element into another midstream element or the Alaska to Alberta Project and is defined in Article 1.35 of the Contract.

use its firm transportation services to off-take points, provided they are upstream of the firm contracted service point. As a practical matter, it is advisable that capacity for in-state service be obtained in the open seasons. Otherwise, in-state shippers might be accommodated at the discretion of the pipeline or if FERC later orders the pipeline to accommodate in-state shippers (Order 2005-A, page 30). Commitment to in-state capacity in the open season avoids issues of stranding mainline capacity downstream of in-state deliveries or interference with the right of capacity holders to meet their shipping commitments.

In-state distribution systems are described in Article 9.3. The contract does not require any party to fund/install/maintain any facilities downstream of any off-take point. Facilities are considered separate from the mainline. However, the contract requires the mainline entity to cooperate with any person sponsoring facilities that would interconnect with an off-take point in the planning/design of such facilities, consistent with FERC policy.

Article 9.4 describes in-state gas sales contracts. Any party may, but is not required to, sell gas to an Alaskan purchaser. Outside of an open season, any party may make changes or new arrangements for delivery in Alaska as long as it does not cause the stranding of capacity or the shifting of cost responsibility to holders of preexisting shipping agreements unless mutually agreed upon by all affected parties. Shippers already transporting gas out of Alaska may choose to deliver in Alaska so long as they continue to satisfy their shipping requirements outside of Alaska.

The contract requires that changes or new arrangements not shift costs to the holders of pre-existing shipping commitments or create excess pipeline capacity unless mutually agreed with everyone affected. For example, if the state decided to shift deliveries of gas from Alberta to an in-state off-take point, the state would still be responsible for that portion of costs for providing the capacity to deliver the volume of diverted gas from the off-take point to Alberta. The state could avoid this cost if it found additional gas to ship to Alberta, or alternatively, in this example, the in-state purchaser could agree to keep the state whole for its unused capacity charges downstream of the in-state off-take point. In a second alternative, the pipeline could be expanded, within reasonable parameters, to accommodate the increased in-state flows if incremental gas were available to ship on the line.

Article 9.5 of the contract requires that before the commencement of the initial open season, the mainline entity must conduct a feasibility study of NGL processing opportunities in Alaska. The results of the study must be summarized in the project summary. The individual owners of gas will determine the processing of NGLs based on their commercial decisions.

3.7 Dispute Resolution

The producers proposed that all disputes arising under the contract be resolved by a standard arbitration process. The state and the producers ultimately agreed on the arbitration process that is set forth in Article 26 and certain exhibits of the contract.[28]

[28] As the North Slope's oil resources were developed, the state and the producers engaged in a series of major cases concerning the valuation of North Slope oil for tax and royalty purposes and the proper transportation charges that affect valuation. There were court cases, regulatory cases followed by court appeals and private arbitrations. These cases were complex, costly, and protracted.

The mandatory dispute resolution process described in Article 26 and elsewhere in the contract is intended to “exclusively and finally” resolve all disputes arising under the contract between the state and one of more of the parties. Article 26 does not affect the right of third parties to challenge the validity or constitutionality of any aspect of the contract. What constitutes a dispute is broadly defined in the contract.

The procedures to be followed when a dispute arises are described in the contract. They are modeled after the rules of the International Institute for Conflict Prevention and Resolution (CPR) but adapted for the special circumstances of the contract. A description of the process follows. A more detailed summary of Article 21 is provided in Appendix E of this document.

When notice of a dispute is given, the parties must first endeavor to resolve the dispute in an informal “amicable resolution” process. After identifying the issues and exchanging information that assists understanding and resolving the issues, each side will designate a senior executive as its representative. The senior representatives then attempt to negotiate a resolution of the dispute. The contract sets a time limit of 120 days for completion of the informal dispute resolution process. By agreement, the parties can explore other forms of informal dispute resolution, including mediation.

If informal dispute resolution is unsuccessful, the parties then begin the arbitration process. The first step in the process is for the parties to send a notice of arbitration that states the claim, whether the party wants the dispute to be resolved through baseball arbitration[29], and whether the dispute is with a single participant or involves a multi-party dispute. Next, the parties jointly attempt to select a panel of three arbitrators. If the parties cannot agree on the arbitrators, then the CPR is asked to recommend qualified arbitrators. Qualifications for the arbitrators are set forth.

The arbitration is governed by the U.S. Arbitration Act, not Alaska’s Uniform Arbitration Act. Otherwise, the substantive law of Alaska applies except for its conflict of laws’ principles.

The place of the arbitration is to be established by agreement of the parties or, if the parties are unable to agree, by the arbitration tribunal. The contract also specifies the parties’ rights to discovery and defines those rights in terms of the size and nature of the dispute. All arbitration proceedings are confidential with a limited exception.

Dispute may arise between the state and a participant or between the state and multiple participants. The latter is described as a multi-participant dispute. There may be certain procedural differences depending on whether the dispute is a multi-party dispute or not.

The arbitration tribunal conducts the arbitration process, rules on procedural issues, presides over the hearing and ultimately renders a decision. As part of its decision or as necessary to conduct the arbitration process, the arbitration tribunal is given the right to apply the remedies that a court might adopt subject only to certain limitations that the contract or existing law imposes. The costs of the arbitration panel are divided among the parties. Ordinarily, the arbitration tribunal is expected to render its decision within six months of the pre-hearing conference in a particular dispute.

[29] Baseball arbitration is also referred to as "last best offer" arbitration, in which each party submits an offer to an arbitrator and the role of the arbitrator is limited to choosing one offer of the two or more offers.

After the arbitration tribunal has reached a decision, the winning party must go first to the state courts in Alaska to confirm and enforce the decision. If the Alaska state court that is assigned the case does not enter a final judgment within one year, the winning party is free to seek enforcement from any state court in the United States that has jurisdiction.

4 Analysis of the Contract

The agreement on a stranded gas contract is another marker on the road to an Alaska natural gas pipeline. The contract provides the sponsor group with fiscal certainty and the state with fiscal benefits. The contract gives the state the right to own 20 percent of the gas treatment plant, the mainline (including compressors and other related facilities), and the mainline to the Alberta hub. The state will also take possession of approximately 20 percent of the gas which places the state in the position of becoming a major owner and marketer of gas. The state also has the right to ownership in other pipelines that feed the project and a pipeline from Alberta south to the lower 48 states; the state's share of ownership will be in proportion to its share of gas in these pipelines. Also, the contract requires that the state relinquish certain rights under the lease for royalty gas and under regulation for tax gas.

Finally, the contract contains special clauses to protect other interests Alaska considers critical. Specific clauses give protection for intrastate users (see Articles 8.7 and 9.4. A special clause gives the state the right to pursue expansion of the pipeline above and beyond the unique powers Congress gave FERC in the ANGPA (see Article 8.7). Creating and protecting opportunities for Alaskan workers and businesses are addressed. Each of these and other major provisions is addressed in subsequent sections of this document.

The state negotiating team was guided by Governor Murkowski's six gasline principles in developing the contract. These principles are used to analyze the contract terms and the merits of the proposed pipeline project. In addition to the guiding principles, other important contract issues that were necessary to address the requirements of the sponsor group are addressed in this section.

4.1 Alaskans Deserve a Fair Share of the Revenues

Alaskans deserve a fair share of the revenues and the contract achieves that principle. The governor's first gasline principle focuses on the balance that must be struck between the state's interests to maximize its revenues and the need to develop a commercially viable project. The emphasis on a fair share for the State of Alaska is important to this discussion. A fair share of the revenues will enable the project to move forward and the subsequent revenues will enable the state to support quality education, healthy and safe communities, and protect the most vulnerable seniors and children. In addition, approximately 28 percent of the royalty gas sales will go to the Permanent Fund and increase future Permanent Fund dividends.

This section presents the projected fiscal benefits of the proposed contract to the State of Alaska and municipalities. The revenue generating elements of the project such as tax and royalty payments, impact payments, and revenues from state equity ownership in the project are provided. The analysis compares fiscal and economic effects to the state of the proposed contract terms with the existing fiscal structure (fiscal terms in effect as of December 2005). The following subsection discusses the analytical models used in various analyses conducted for this findings and determination document.

4.1.1 A Caveat on Models and Assumptions

Due to the enormous scope of this finding, a large amount of historical data, assumptions, and calculated results appear throughout this preliminary findings and determination. This body of information is central to understanding the complexities of the contract and to formulating the recommendations, conclusions and findings contained in this document. In some cases different methods and assumptions were used in the various analytical models because the objective of the analysis was focused on particular issues or attributes of the fiscal contract. While differences in various analysis and results were sometimes not easily reconciled, significant effort was undertaken to identify and correct inconsistencies.

The information used for this report came from materials developed over a long period of time. Some of the background studies and reports were prepared before the SGDA was extended and amended in 2003. In connection with negotiating a contract, others were prepared in 2003, 2004, 2005 and 2006. This poses the question as to whether the numerical assumptions and results used to negotiate the contract with the producers should be presented as originally formulated or should these studies and reports be updated for the sake of consistency. The commissioner decided in favor of the former approach.

4.1.1.1 Models used in the Analysis

Various analytical models were used to support the state's position during the negotiating process and in preparing this fiscal findings and determination:

- the ADOR cash flow model, primarily developed by Roger Marks;
- the ADNR cash flow model, primarily developed by Greg Bidwell and Dr. William Nebesky;
- the PVM cash flow model, developed by the state's primary consultant, Dr. Pedro Van Meurs; and
- the Information Insights, Inc. regional and statewide economic model.

The PVM model is a gas only model. It does not take into consideration the investments in oil production, oil revenues and oil losses in Prudhoe Bay. The PVM model was primarily used for the following purposes: (1) to analyze the economic parameters that the members of the sponsor group consider when ranking the project with other worldwide alternative investment opportunities, and (2) to compare the Alaska fiscal regime with those of competing alternatives.

The ADOR and ADNR models both have oil and gas components. Both models analyze the impact of the proposed fiscal terms for oil and gas on the state fiscal system over the long run; although the ADNR model is more complex than the ADOR model.

The Information Insights model was developed to compare project alternatives, specifically the projects of the sponsor group and the AGPA. The model compares values of gas at the wellhead, fiscal impacts on the state treasury, and overall impact on the state economy.

The three cash flow models describe in great detail the gasline project economics and its relationship to fiscal system tax and royalty elements. These models quantify expected investment, production, price, revenue, cost, and financing for ANS gas pipeline development over a 45-year forecast horizon. The models incorporate complex technological and commercial relationships, as well as state, federal, Canadian, and relevant lower-48 tax and royalty fiscal system attributes. The models provide a platform for systematic evaluation of fiscal system changes in terms of various economic performance factors for the project and for state and federal government revenues. Key project performance factors include: yearly and cumulative cash flows, net present values, internal rates of return, profit-to-investment ratios, years to payout, and in some cases, expected monetary values. The models incorporate elements of the proposed fiscal contract and describe the implications for various state revenues and for state GTP/mainline ownership and gas marketing.

At several points in time, the first three models were cross-tested based on the same inputs in order to ensure that they exhibited internal consistency and provided reliable results. Slightly different results may be attributed to the different, but equally valid methods used to reach the result.

After weighing the considerations discussed above, at the risk of minor confusion, it was concluded it was most appropriate to use the results from each model and not attempt to adjust the numbers throughout the various sections of the report to achieve consistency.

At the time this document was prepared, deliberations on the PPT were still ongoing. The analysis and financial results presented in this report assumes that the PPT will be similar to that contained in the House Finance Committee substitute for Senate Bill 305 as of midnight on May 7, 2006. An update of the fiscal interest findings and determination will be prepared after the final PPT is available.

4.1.1.2 Discounting Policy for Proposal Evaluation

The design and scope of the proposed ANS gasline project involves a lengthy period of construction and long lead times from project sanction to startup and eventual operations. Also, the proposed project spans a period of fiscal stability on gas that could reach 45 years. Consequently, project costs and benefits will be separated by significant spans of time. Policy makers need a way to compare time-distinct monetary impacts. Discounting is a technique that weights costs and benefits occurring at different points in time so they are comparable. Discounting is appropriate because (1) people generally prefer present to future consumption (they have time preference) and (2) resources that are invested will normally earn a positive return. People give up that expected return on investment when they consume resources today. This opportunity cost implies that, apart from time preference, current consumption is more highly valued than future consumption.

The choice of the appropriate discount rate is a highly contentious subject that depends on many factors. Chief among these are (1) the type of analysis that is being performed (economic versus financial), and (2) to whom the benefits and costs apply (the sponsor group versus the state).

The ADNR enlisted consulting services that examined the matter of the appropriate discount rate the state should adopt for evaluating the costs and benefits that would accrue to the state from the proposed project. Several key questions were considered in the report (Newell, 2004):

- Do major oil/gas companies use a different discount rate than the government?

- Should the state adopt a corporate discount rate when assessing its participation in pipeline project alternatives?
- What rate should the state use, and how should it account for project risk and uncertainty?

The report concludes:

> First, there are good reasons for the state to use a different discount rate than oil and gas companies. Second, the state should not adopt a corporate discount rate when assessing its participation in pipeline project alternatives. Third, a reasonable benchmark rate for the state to use is 5 percent nominal, or 3 percent real (assuming 2 percent inflation), with additional sensitivity analysis of this rate and separate accounting for project risks and uncertainties. This rate could differ if the market interest rate on funds used for project purposes was to change significantly from present levels.

In light of these findings and, given the general upward movement in interest rates over the intervening 18+ months of proposal evaluation, the economic analysis presented in this document draws from various studies that employ nominal discount rates for state revenues ranging from 5 to 8 percent. A 10 percent nominal discount rate is applied to the sponsor group's costs and benefits stemming from the project.

While the contract was being negotiated a six percent discount rate was used to estimate the net present value of the fiscal terms, with an objective of ensuring that the total net present value of revenues to municipalities was higher with the proposed contract. The North Slope Borough receives a lower net present value under the contract terms because of the time value of money. A higher discount rate is used for state revenues because the state has higher opportunity costs. The state owns the assets in the Permanent Fund, which are expected to earn 8 percent annually on a long-term average. Most municipalities have no such fund; instead, the highest opportunity cost the municipalities have is their borrowing cost (reinforced by the state's credit), which is approximately 6 percent.

Under AS 43.82.400, the SGDA requires that the projected public revenue from the project be compared with the estimated operating and capital costs of the additional state and municipal services arising from the construction and operation of the project over the term of the contract. The following section provides the revenue and cost comparison.

4.1.2 Total Revenue from Project

The results presented in this section are the output from the ADOR model using both the 2005 fiscal structure and the proposed contract with PPT for oil and gas. The ADOR computer model uses confidential information from the sponsor group to estimate the fiscal effects of the gas pipeline project and oil production from the ANS.[30]

Cumulative total state revenues (including proceeds to municipalities) from all sources under the fiscal contract, including the PPT, would be expected to range from $86 to $306 billion, depending on future sustained prices for gas and oil. This translated to between $16 and $70

[30] The sponsor group's information on project cost was subject to independent verification by Paragon Engineering Services (2004).

billion, respectively, in discounted net present value terms. These cumulative state revenues are compared with 2005 fiscal system revenues at different prices, with and without the PPT, in Table 6.

Table 6. Comparison of Total State Oil and Gas Revenues

	Revenues of Project Under 2005 Fiscal System			Revenues of Project Under Proposed Contract		
	2005 Oil	2005 Gas	Total	PPT Oil	SGDA Gas	Total
Price Level/Results	Revenues ($ Billions)			Revenues ($ Billions)		
$3.50 per mmBtu of Natural Gas at Chicago City Gate/$22 per barrel of WTI Crude Oil						
Nominal $						
Total (2007-2050)	33	57	90	29	57	86
Present value (at 8%)	11	8	19	9	7	16
Real $ (2005)						
Total (2007-2050)	20	28	48	17	28	45
Present value (at 6%)	10	7	17	8	6	14
$5.50 per mmBtu of Natural Gas at Chicago City Gate/$35 per barrel of WTI Crude Oil						
Nominal $						
Total (2007-2050)	66	101	167	71	101	172
Present value (at 8%)	22	14	36	24	13	37
Real $ (2005)						
Total (2007-2050)	42	52	94	46	52	98
Present value (at 6%)	21	13	34	23	12	35
$8.50 per mmBtu of Natural Gas at Chicago City Gate/$55 per barrel of WTI Crude Oil						
Nominal $						
Total (2007-2050)	111	167	278	158	167	325
Present value (at 8%)	37	24	61	52	23	75
Real $ (2005)						
Total (2007-2050)	73	90	163	96	90	186
Present value (at 6%)	35	22	57	46	21	67

Source: ADOR model.

Notes: Total revenues are expressed in billions of both nominal and real dollars over the period 2007 to 2050.

The estimates above are based on the following assumptions:

1. PPT provisions are per the House Finance Committee substitute for Senate Bill 305 as of midnight on May 7, 2006.
2. Revenues for the gas proposal are net of all state expenses, including investment and the 20 percent investment credit.
3. Revenue streams include total state revenues including royalties, severance tax, property tax, and corporate income tax.
4. The property tax numbers do not include TAPS.
5. Debt from state investment is retired by the end of 2035 (20-year debt).
6. Ability to tax facility and equipment exists before gas pipeline is built.
7. SGDA gas includes earnings from ownership of the gas.
8. Assumes an Alaska to Alberta project.

Projections of future revenues and costs associated with the project require assumptions about construction and operating costs, the market price of oil and gas, future production of Alaska oil and gas, and the impact of pipeline construction and operation on the cost of providing local and state governmental services. Some of the major assumptions used to calculate revenues and costs associated with the proposed pipeline are shown in Table 7.

Table 7. Assumptions

Cost or Revenue	Estimated Value
Price of gas Chicago City-gate (2005$) per mmBtu (base case)	$5.50
Price of oil West Texas Intermediate (2005$) per barrel	$35.00
Production rate/volume of gas (bcf/day (includes CO_2)	4.7
Volume of gas sold (bcf/day)	4.2
Projected recovery	53 tcf
Pipeline, GTP, etc.	
Construction cost (2005$)	$21 billion
Operating costs over 35 years (2005$)	$ 9 billion
Additional upstream investment costs including PTU, feeder lines, and yet-to-find gas fields	$5.7 billion
Costs to local government (2003$)	$125.0 million
Payments to offset impacts to local governments	$125.0 million
State's share of Impact Payments	$25.0 million
Inflation rate (%)	2
Discount rate for net present value (NPV) calculations for state (%)	8
Discount rate for net present value (NPV) calculations for municipalities (%)	6

West Texas intermediate (WTI) oil is a global benchmark for oil prices; ANS oil sold on the west coast of the United States typically sells for $2 less per barrel than WTI. The $35.00 for WTI presented above is considered to be the long-term price that major oil companies are using for planning purposes (See Section 5.1). A barrel of crude oil has about 5.8 mmBtu so, assuming Btu parity between gas and oil, natural gas prices per mmBtu are typically about 1/6 of the price of a barrel of oil. A west coast ANS price of $33 would result in an approximate price of $5.50 for natural gas.

The model is based on a natural gas production rate of 4.7 bcf/day, and sales of approximately 4.2 bcf/d. The difference between the two numbers is composed of impurities such as CO_2 that are removed from the natural gas stream, fuel use, and similar factors. The total production over 35 years is about 53 tcf.

In addition to the project costs of approximately $21 billion, it is estimated that an additional $5.7 billion will be required to develop the gas field infrastructure of known and yet-to-be-discovered gas fields. The operating costs for the project are estimated at $9 billion over the 35-year operating period. There is additional gas field operating costs but this is not included since much of these costs are also associated with the production of oil.

Local governments are estimated to incur costs of about $125 million during construction of the project, and $125 million is available from the parties to mitigate the impacts of these costs. As a 20 percent owner of the project the state will be responsible for contributing $25 million to the impact payment. In addition to these local government costs, the state may incur up to $800 million for rehabilitation of roads and highways after the gas pipeline construction is complete (See Section 8).

The ADOR model uses an inflation rate of two percent per year. The long-term nominal discount rate for the state is assumed to be about eight percent, composed of the two percent inflation rate and a market interest rate of funds for the project of between five and six percent.

The department developed projections of annual oil and gas revenues to the state, net of state investment, and to the NSB and FNSB with and without a natural gas pipeline in Table 6. Revenues are estimated under three different price assumptions for oil and gas. Impact payments of $125 million over a six-year period, as required in Article 18.1 of the contract are included Table 6 as a source of revenue to the state.

The ADOR computer model estimates state's oil and gas revenues from 2007 to 2050 under the 2005 fiscal structure and under the proposed contract terms (Table 6Table 6).[31] The ADOR model results indicate that gas revenues are about the same under either fiscal structure. The results for gas are similar because the contract terms retain the same royalty share for the state, and the contract production payment of 7.25 percent is approximately the same as the existing production tax (10 percent) and adjusting down for the ELF.

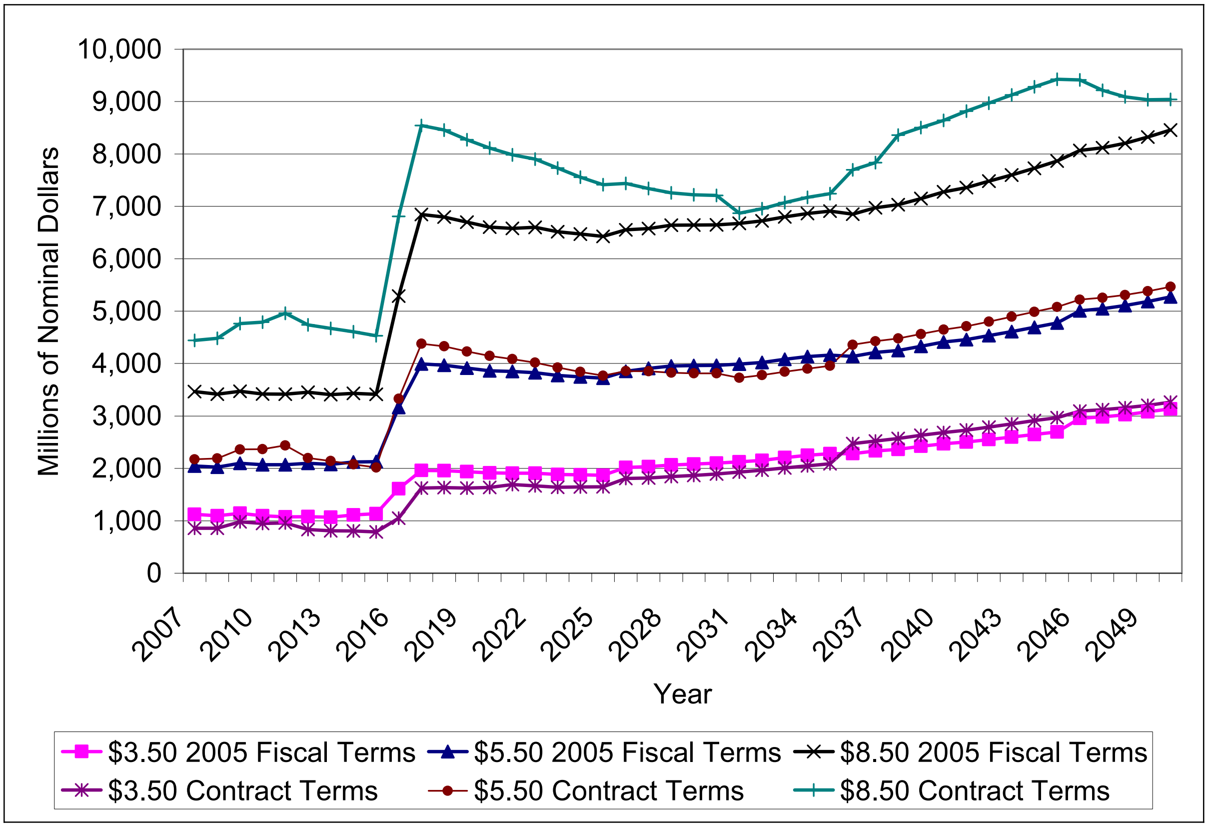
The net revenue numbers in Table 6 reflect the Alaska to Alberta project. However, the net revenues for the Chicago project are not materially different since the price of gas in Alberta simply reflects the price of gas in Chicago less the transportation cost between Alberta and Chicago. Alberta revenues could be slightly higher in later years to the extent existing pipeline capacity between Alberta and Chicago is utilized and is fully depreciated. However, though the net revenue difference between Alberta and Chicago may be small, the differences in the rate of return are very large; while the Alberta and Chicago alternatives have similar net revenues, the cost of getting to Chicago is several billion dollars more.

Figure 15 shows the total revenues (including pipeline earnings) accruing to the state over the duration of the contract in nominal dollars. The revenues from gas are about the same under either fiscal system at any price. For oil revenues, because of the PPT, the new fiscal system provides slightly less at low prices, slightly more at medium prices, and a substantial amount more at higher prices. Figure 16 shows the total revenues (and earnings) accruing to the state over the duration of the contract in real 2005 dollars. Both of these figures portray the total revenues with an Alaska to Alberta project. Energy prices in Figure 15 and Figure 16 reflect Btu equivalency. Prices are shown for gas only; the comparable oil prices would be:

Oil Prices ($ per barrel)	Gas Prices ($ per mmBtu)
22	3.50
35	5.50
55	8.50

[31] The revenue model developed for evaluation of the gas project does not have all of the detail as in the Department's model used semi-annually by the department for estimating future state revenues, so the results of the two models differ.

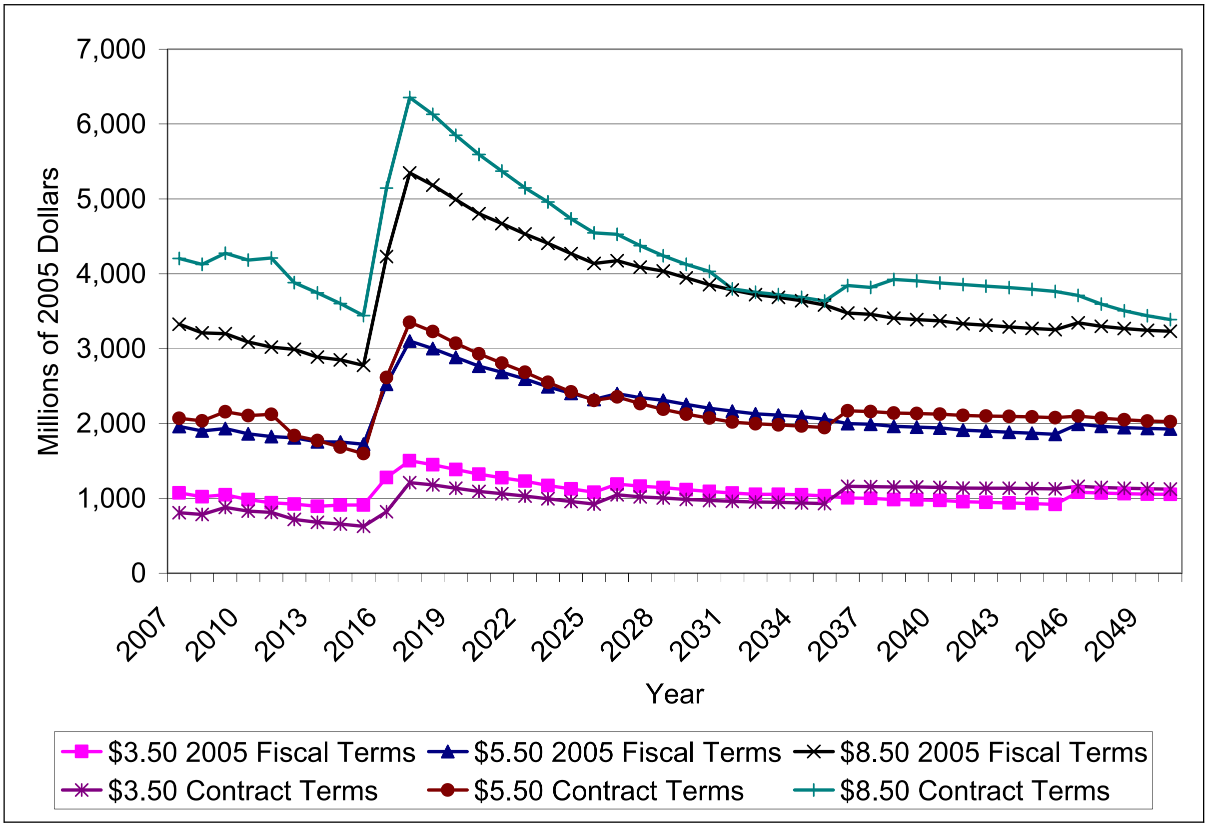
Figure 15. Total Alaska Revenue at Different Energy Prices in Nominal Dollars



Source: ADOR model.

Note: Natural gas prices are Chicago City-gate prices and oil prices are WTI crude oil.

Figure 16. Total Alaska Revenue at Different Energy Prices in Real Dollars



Source: ADOR model.

Note: Natural gas prices are Chicago City-gate prices and oil prices are WTI crude oil.

4.1.2.1 State Revenue and Cost Components

The state's revenues and costs that are included in the computer model for the gas project are presented in Table 8. The table illustrates the breakdown of costs and revenues under the 2005 fiscal terms in nominal dollars. The net revenues depict income for gas only, and do not contain revenues from oil production.

Table 8. Gas Pipeline Model Revenues and Costs

Revenues	$ Billions	Costs	$ Billions
Gas sales	$87	Principal and interest	$7
Tariff income on excess capacity	$2	Operating costs	$3
Net profit shares on PTU	$0	Marketing costs	$1
Corporate income tax	$14	Upstream cost allowance	$4
Upstream PILT	$2	Property taxes in Canada and the Lower 48	$1
Midstream PILT	$3	Income taxes in Canada	<$1
PILT on distribution lines	$1	State's share of Impact Payments	<$1
Impact payments	<$1		
Local NPR-A distributions	$8		
Total:	$117		$16

Source: ADOR model.

Notes:

1. Values are expressed in billions of nominal dollars.
2. Values shown are total costs and revenues over the period 2007 to 2050 under the 2005 fiscal system.

4.1.2.2 Break Even Analysis for State Revenues

The ADOR also performed sensitivity analyses to determine the point at which changes in prices and costs caused cash flows to the state to turn negative. The breakeven analysis showed that at the Alberta project cost of $13.6 billion (in 2005 dollars), a Chicago city gate price of $1.69/mmBtu in real terms or $1.40/mmBtu in nominal terms caused the state's cash flows from the project to turn negative. This analysis did not include revenues from oil, which presumably at that gas price would also be small.

The sensitivity analysis also examined the magnitude of cost overruns that would cause the state's cash flows to turn negative at various gas prices. At a 20 percent cost overrun, the real gas price would need to remain above $1.84 in real terms for the state's cash flow to remain positive, and at a 50 percent cost overrun the state would need to receive gas prices of $2.05 to retain a positive cash flow (See Table 9).

Table 9. Sensitivity of State Cash Flow Projections to Cost Overruns

Percent Cost Overrun	Alberta Project Cost ($Billions)	Gas Price (Chicago city-gate $/mmBtu)	
		Real Price	Nominal Price
0	$13.6	$1.69	$1.40
20	$16.3	$1.84	$1.54
50	$20.4	$2.05	$1.75
100	$27.2	$2.41	$2.09
150	$34.0	$2.77	$2.44
200	$40.8	$3.13	$2.78

Source: ADOR model.

4.1.2.3 Municipal Governments

Because the contract anticipates changes in royalty and other payments, the ADOR has estimated state and local revenues under the fiscal regime existing at the end of 2005 and the proposed contract (See Table 10). Impact payments are excluded as a source of revenues to the municipalities because it is not yet known how those funds would be allocated. The model results indicate that the nominal dollar stream of revenues to the NSB and the FNSB from 2007 through 2050 would be higher under the proposed contract than it would be under the 2005 fiscal system. The net present value of the revenue stream under the contract would be higher for the FNSB but lower for the NSB. The total net present value of the revenues to the two municipalities is higher under the proposed contract.

Table 10. Comparison of Projected Revenues to the North Slope Borough and the Fairbanks North Star Borough

	2005 Fiscal System		Proposed Contract	
Revenues	North Slope Borough	Fairbanks North Star Borough	North Slope Borough	Fairbanks North Star Borough
Total 2007-2050 (Nominal $)	4,473	217	4,708	384
NPV 2005$ at 6%	1,308	78	980	82

Source: ADOR.
Notes:
1. Gas pipeline project revenues only; excludes oil and TAPS.
2. The contract terms for oil replicate the 2005 fiscal terms and oil revenues to the NSB are similar under either system and are not included here.

Under the 2005 fiscal system, the NSB could levy a property tax on the project while it was under construction, and receive some revenues five to six years earlier than under the proposed contract. During the contract negotiations it became apparent that this taxation prior to the flow of revenues from the project had an adverse effect on the project economics and was in conflict with one of the balancing principles of the SGDA, which states that the state and municipal revenues should be relatively lower in the earlier years than in the later years of the project. The total revenues to the NSB are greater under the contract but because of the delay in receiving those funds the net present value is lower.

4.1.2.4 Alaska Permanent Fund Corporation

The Alaska Permanent Fund Corporation (APFC) will be the recipient of an estimated 28 percent of the gas royalties that accrue to the State of Alaska[32]. Table 11 shows the anticipated revenues to the APFC over the first 10 years of the project. These revenues are included in the total state revenues shown in Table 6.

[32] Prior to 2004, oil and gas from leases issued after 1979 had a Permanent Fund contribution rate of 50 percent of royalties, while all older leases contributed at 25 percent. In 2004 the legislation was changed so that all leases contributed at 25 percent. However, once the individual Permanent Fund dividend is reduced by $20.00 because of the reduced contribution rate, the rate for the newer leases reverts back to 50 percent. About 2/3 of Point Thomson leases are pre-1979, and 1/3 after 1979. The Permanent Fund Corporation estimates that so far the provision has reduced dividends $1.85. It was 52 cents after 2004. They do not have an estimate of when the cumulative reduction will reach $20. The assumption is made that $20 is reached by 2016, which results in a weighted average contribution rate of 28 percent.

It should be noted that there is also a benefit to the APFC of receiving royalties from gas production sooner rather than later because APFC can invest these funds and begin to generate investment returns.

Table 11. Potential Revenues to the Alaska Permanent Fund Corporation from Project Gas Royalties

Year	$3.50/mmBtu	$5.50/mmBtu	$8.50/mmBtu
	Permanent Fund Revenues (Nominal $ millions)		
2016	52	127	240
2017	110	263	493
2018	115	271	506
2019	120	280	519
2020	126	288	532
2021	133	301	552
2022	141	312	570
2023	146	320	583
2024	151	329	596
2025	157	338	609
10-Year Total	**1,251**	**2,830**	**5,199**

Source: ADOR model.
Note: Assumes 28 percent royalty contribution rate; See Footnote 32.

4.1.3 Estimated Earnings from State Ownership

The amount of money the state would generate from the return on its equity investment in the project will depend on a number of factors, many of which are not yet known. Earnings are used here to note the return the state will get from its investment compared to the revenues it will obtain from sales of its gas. Total revenues would incorporate both earnings and gas revenues. The following assumptions are used to estimate earnings from pipeline equity ownership:

- a $13.6 billion pipeline to Alberta (including the gas treatment plant) and an additional $7.4 billion pipeline from Alberta to Chicago;
- the state owns about 20 percent of the pipeline;
- the state finances its 20 percent ownership with 20 percent equity and 80 percent debt;
- the state may finance its equity share from any number of sources, and for this analysis, with moral obligation debt with a 6.5 percent interest rate over 20 years; with a cash investment the state's opportunity cost would be about the same or possibly higher;

- FERC awards a 14 percent after-tax return on equity for U.S. assets, and Canadian regulators award a 12 percent return on equity for Canadian assets; and
- the pipeline has a 30-year depreciation period.

The earnings from pipeline ownership are the difference between the rate of return on equity awarded in the tariff, and the cost of capital for the state's equity share. Note that the state could finance its equity share with mechanisms other than moral obligation debt, including, for example, cash, or an investment from the Permanent Fund. All of these would have opportunity costs, and the income would be the difference between the return on equity and the opportunity cost. Moral obligation debt is used here as an example for quantifying the illustration.

There may be excess capacity in the gas transmission pipelines that extend from Alberta to the lower 48 states; the model therefore considers a terminus at Alberta and in Chicago. It is estimated that the state could theoretically earn about $707 million on its equity investment in a pipeline to Alberta over a 20-year financing period or about $1 billion for investment in a pipeline to Chicago (see Table 12). If less than four bcf/d is shipped to Chicago, the state's ownership earnings would be between these two estimates, assuming the other assumptions remain in place.

Table 12. Estimated State Earnings from Pipeline Equity Ownership by Segment

Destination	Unit of Value	State Equity Contribution ($ Millions)	Total State Pipeline Ownership Earnings ($ Millions)
Alberta (base case is with inflation)	Nominal	672	707
	Constant (2005$)	572	577
Chicago	Nominal	1,019	1,087
	Constant (2005$)	866	888

Source: ADOR model.

Note that the state will not pay state or federal income taxes on its in-state share of the pipeline, and will only pay property taxes to itself through its midstream entity. Not paying these taxes is neither cost savings nor earnings. In the case of property and state income taxes, the state would be paying this tax to itself on its share of the infrastructure and gas, so there is no net effect on cost. In the case of federal income taxes, if the tariff is maintained at the same cost over the years, the effects of accelerated depreciation are so great on a time value of money basis that eliminating the income taxes slightly increases the tariff.

4.1.4 Monetary Payments

The contract replaces the existing property tax system that generates revenues for the state and local governments with several in lieu of payments (Articles 15, 16 and 17). Article 15 (upstream facilities payment) replaces the property tax on the existing oil field infrastructure and future gas field infrastructure. Article 16 (midstream payment) replaces property taxes on the proposed gas pipeline, the GTP, and any gas transmission lines, and Article 17 is proposed to address payments in lieu of oil pipeline property taxes, but is still being negotiated.

Table 13 shows the total estimated amounts in nominal and constant dollars that would be received by the state and local governments over the project term (2007 to 2050) from each of these payments. The estimates shown in the table exclude the TAPS.

Table 13. Monetary Payments to State and Municipalities

Monetary Payment	State	Municipalities
	(Millions of Nominal $)	
Upstream facilities oil payment	213	4,175
Upstream facilities gas payment	79	1,540
Midstream payment	289	3,552
	(Millions of 2005 $)	
Upstream facilities oil payment	168	3,301
Upstream facilities gas payment	53	1,047
Midstream payment	160	1,936

Source: ADOR Model.

Note: Monetary payments are expressed in both millions of nominal and real 2005 dollars. The amounts are total payments over the period 2007 to 2050.

4.1.5 State Corporate Income Tax Payments

Article 19 replaces the state corporate income tax with an in lieu of payment. In general, the sponsor group would continue to make payments that are equivalent to the SCIT in accordance with existing state statutes and codes. These four monetary payments, rather than taxes, form the basis of revenues for local governments and also contribute revenues to the state.

4.1.6 Impact Payments

While the project is under construction it is anticipated that local governments will incur costs for addressing local economic and social impacts resulting from construction activities, temporary population increases, and other factors. Local governments will receive an impact payment from the mainline entity to cover these increased costs associated with these economic and social impacts. A report prepared for the Municipal Advisory Group identified about $125 million (2003$) in costs for local governments and others to address the potential impacts from the project.[33]

The impact payments cited in Article 18 of the contract total $125 million and will be paid over a six-year period. The first payment would occur at the end of the calendar year immediately following project sanction. The annual payment schedule is shown in Table 14. As a 20 percent owner in the project, the state will pay 20 percent of this payment, or $25 million.

[33] Information Insights, 2004.

Table 14. Impact Payments Schedule

Year	Amount ($millions)
1	8.90
2	16.60
3	27.70
4	27.70
5	26.00
6	18.10
Total	**125.00**

If any of the impact payments occur nine years after the effective date, those payments will be adjusted for inflation using the CPI for the ninth year as the base.

4.2 Alaskans Need Access to the Gas

Affordable energy is vital to growing a healthy economy throughout Alaska, and new energy sources are critical to the railbelt and southcentral Alaska, as well as interior communities. Access to the gas from the ANS is a key element in meeting these needs.

The following subsections provide an overview of:

- Historic In-state Consumption of Natural Gas
- Historic Production of Natural Gas from the Cook Inlet Basin
- Projected In-state Gas Demand
- Lateral Spur Pipeline for ANS Gas
- Natural Gas Liquids and In-state Use
- In-state Distribution of ANS Gas
- Identification and Selection of Offtake Point

4.2.1 Historic In-state Consumption of Natural Gas

Natural gas is currently produced at Cook Inlet and the North Slope. Cook Inlet gas is consumed by residential, commercial, power generation and industrial users in the southcentral and interior regions. Most ANS gas produced in association with oil operations is re-injected for field maintenance. A small portion (297 billion cubic feet or about four percent) is used for oil field equipment, operations, and pipelines (including the first four TAPS pump stations), and for local sales to North Slope utilities. In rough terms the annual North Slope industrial gas consumption is approximately 50 percent greater than the annual gas produced and consumed in the Cook Inlet basin.

Annual Cook Inlet gas consumption averaged over the five-year period 2001-2005 was 203.5 bcf. Table 15 shows historical Cook Inlet gas consumption by major group since 1990. Gas consumed for power generation and space heating (utility gas) has increased in step with steady growth in residential and commercial demand. Until recently, industrial use of Cook

Inlet gas (the LNG and ammonia-urea plants) has remained fairly constant since 1990. Gas consumed in field operations has followed the pattern of oil production in the Cook Inlet basin.

On average, over the past five years, industrial uses—LNG, ammonia-urea plant, and field operations—have accounted for about two-thirds of total Cook Inlet gas consumption; utilities and power generation account for the remaining one-third (see Table 15). [34]

Table 15. Historical Cook Inlet Natural Gas Consumption by Major Group, bcf per Year, 1990- 2005

Year	Power Generation	Gas Utilities	LNG	Ammonia-Urea	Field Operations and Other	Total
1990	38.9	25.9	65.1	54.8	25.8	210.5
1991	35.3	24.7	65.4	52.6	28.6	206.6
1992	33.5	25.9	66.2	55.0	27.6	208.2
1993	32.0	24.2	67.3	56.2	20.7	200.4
1994	33.0	26.6	76.7	55.4	22.3	214.0
1995	34.0	26.7	78.1	54.0	21.6	214.4
1996	36.1	29.0	81.4	54.0	24.8	225.3
1997	37.7	26.6	75.4	52.3	22.4	214.4
1998	33.4	27.4	78.1	53.6	22.5	215.0
1999	34.6	32.0	78.0	53.9	14.9	213.4
2000	36.8	29.1	78.5	49.0	15.5	208.9
2001	31.6	34.9	75.2	53.9	15.2	210.8
2002	33.7	32.0	73.0	46.3	17.2	202.2
2003	36.6	33.0	74.0	40.2	16.6	200.4
2004	42.1	33.1	71.1	39.5	14.5	200.2
2005	41.8	33.3	74.9	40.4	13.5	203.9
Average for past 5 years	37.2	33.3	73.6	44.1	15.4	203.5
Average % past 5 years	18%	16%	36%	22%	8%	100%

Note: Power generation and gas utilities include residential and commercial demand.
Source: ADNR, (forthcoming).

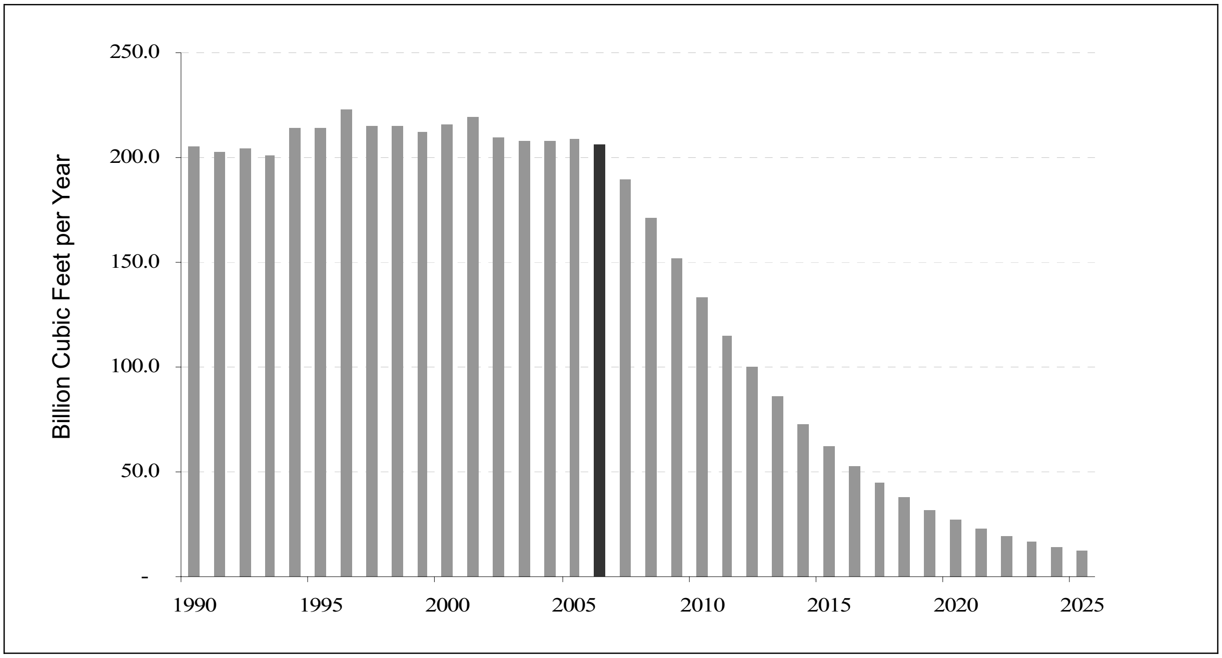
4.2.2 Historic Production of Natural Gas from the Cook Inlet Basin

Until recently, the reserves-to-production ratio in the Cook Inlet basin was comparatively high, in excess of 12-to-1 (meaning, about 12 years of remaining reserves at current rates of production). However reserves replacement in the Cook Inlet basin is not keeping pace with production. Recent Alaska ADNR estimates of remaining reserves indicate a reserves-to-production ratio of about 8-to-1 (ADNR, forthcoming). Without additions to the proved

[34] A local distribution company called Fairbanks Natural Gas (FNG) began operations in 2000 by trucking LNG produced from the Cook Inlet basin. While still comparatively small, the FNG customer base and distribution system have grown sharply to about 1 bcf per year in 2005, in part due to the high cost of energy for space heating in interior Alaska.

reserves base, gas production from discovered fields in the Cook Inlet basin is projected to decline markedly, as shown in Figure 17.

Figure 17. Actual and Projected Cook Inlet Gas Production from Discovered Fields, 1990-2025



Source: ADNR (forthcoming).

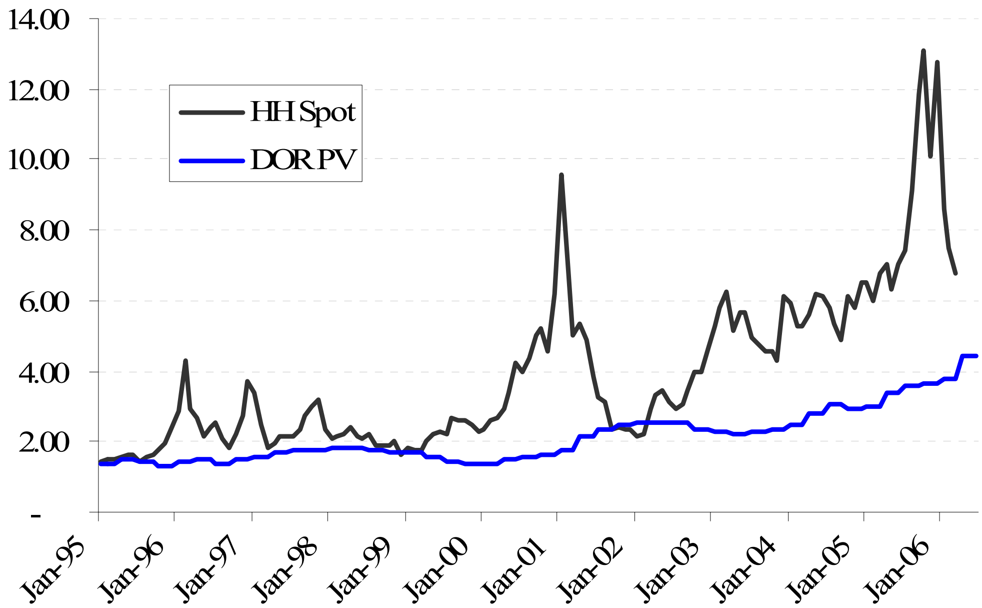
As a whole, the Cook Inlet basin has transitioned in recent years from long-standing excess gas supplies to a condition of gas under-supply. Industrial gas users that depend on low-cost base-load gas are confronted with the implications. For example, the Kenai ammonia-urea plant operated by Agrium, Inc. since 2000 experienced significant gas supply curtailments in January 2006 and currently seeks cost-effective gas supplies for scaled-back plant operations after October 2006. The Kenai LNG plant, operated jointly by ConocoPhillips Alaska, Inc. and Marathon Oil Co. contemplates plant operations beyond April 2009, when its LNG export license expires.

Long-term, cost-effective gas supply is a significant issue for these industrial users but they are not alone. Concern for long-term gas supplies for residential and commercial space heating and for power generation, has resulted in higher-cost utility gas supplies in recent years.[35] The shifting demand-supply balance is reflected in the rising price of Cook Inlet gas to utility consumers, as reflected in the ADOR reported Prevailing Value for Cook Inlet gas (Figure 18). [36]

[35] In October 2001, the RCA, approved a long-term gas supply contract between Unocal (now Chevron) and Enstar, the local gas distribution company that indexes the gas cost to the lower-48 Henry Hub gas price. Currently the RCA is evaluating another Marathon-Enstar gas supply contract that also is tied to the Henry Hub gas price.

[36] Prevailing Value is the weighted average price of significant sales of gas to publicly regulated utilities in Cook Inlet.

Figure 18. Henry Hub and ADOR Prevailing Value for Cook Inlet Monthly Natural Gas Prices



Source: *Platts' Gas Daily,* Monthly average of daily midpoint Henry Hub spot prices and Tax Division, ADOR,
Note: Natural gas prices are expressed in $ per mcf for the period January 1995 to March 2006

4.2.3 Projected In-State Gas Demand

A study conducted for the ADNR by Econ One (Dismukes, 2002) predicted that in-state gas usage over the next two decades has the potential to increase by approximately 140 bcf to 367 bcf per year (Table 16). The report concluded that baseline economic growth represents about 19 percent of this projected increase in gas usage. Fuel switching for power generation in interior communities could account for another 20 percent of this potential growth. Also, the study considered possible added sources of industrial gas demand. Examples cited included petrochemical and internet server facilities as well as expansion of the existing Kenai LNG plant and the ammonia-urea plant if baseline gas supplies were available. It is worth noting that an incremental increase or decrease in industrial load would substantially alter the overall consumption picture. For example, even at current reduced production rates of about 40 bcf per year, annual gas consumption at the Kenai ammonia-urea plant exceeds by 25 percent gas consumption for the entire Enstar distribution system for space heating in southcentral Alaska.

Table 16. Baseline In-State Gas Demand and Potential Growth 2000-2020, Bcf per Year

Instate Baseline in 2000	Residential & Commercial	Industrial	Electric Power	Total
Southcentral[a]	35.3	151.2	35.0	**221.5**
Interior[b]	0.1			**0.1**
North Slope[c]	10.8		0.6	**11.4**
TOTAL	**46.1**	**151.2**	**35.7**	**233.0**
Percent	17%	65%	15%	100%
Potential for Growth in 2020 (Additions to 2000 Baseline)				
Baseline	14.2	8.0	5.1	**27.3**
Expanded Service				
Southcentral	2.2			**2.2**
Interior	4.3			**4.3**
Existing Industrial				
LNG Plant		2.8		**2.8**
Ammonia-Urea Plant		7.2		**7.2**
New or Expanded Industry				
Ammonia-Urea Plant		30.0		**30.0**
Internet Server		4.3		**4.3**
Petrochemical		27.0		**27.0**
Fuel Switching for Power				
Interior (only)			15.0	**15.0**
Gas by Wire (Central Station)				
Interior (only)			12.5	**12.5**
TOTAL in 2020, All Sectors	**66.7**	**230.5**	**68.3**	**365.5**

Notes:

[a] Approximate composition of baseline industrial usage in 2000: LNG=78 Bcfy, Urea=52, Field Ops=20.

[b] Based on usage in 2000 for Fairbanks Natural Gas, LLC.

[c] Barrow Utilities & Electric Coop, Inc., (residential and electric power) plus commercial usage of about 10 Bcf per year at the Prudhoe Bay industrial complex. Estimates exclude TAPS pump stations and North Slope field operations (about 250 bcf per year).

Source: Dismukes, 2002.

A more recent study was prepared by SAIC which found that:

> In the base case, only the residential/commercial and power sectors appear to provide firm demand at the prices at which natural gas can be delivered from the North Slope to South Central Alaska by a spur pipeline. These two sectors provide a demand that could be satisfied by North Slope gas by a spur pipeline designed to deliver about 350 Million Cubic Feet per Day (MMcfd) of dry gas in 2035 to South Central Alaska coupled with 80 MMcfd of natural gas storage to meet seasonal swings in demand. Natural gas liquids to support a petrochemical and propane industry in South Central Alaska could also be viable under the right pricing conditions, and would support a 590 MMcfd wet-gas line. If prices are even more favorable, GTL and LNG could add an additional 700 MMcfd of dry gas demand. A dry gas pipeline of with a

capacity of 1,100 MMcfd would meet total this demand. If NGLs are included the total wet gas pipeline capacity needed would be 1,300 MMcfd.

The demand in Central Alaska is estimated to increase from a yearly average of about 18 MMcfd in 2015 to about 65 MMcfd in 2025, increasing to 75 MMcfd in2035.

The potential for locating a petrochemical industry in the Fairbanks area was not analyzed in detail but the analysis performed indicates that the differences with a South Central Alaska location will mostly be construction, operating and labor cost differences (SAIC, 2006).

4.2.4 Lateral Spur Pipeline for ANS Gas

Many areas of the state are not currently served by natural gas utilities and several potential and current industrial uses could be served by natural gas when commercialization of the major ANS gas project is realized. This gas could be used for commercial, industrial, and residential heating needs as well as for additional electricity generation capacity.

Current studies on existing gas supply and demand in Cook Inlet indicate that, without access to additional gas reserves, annual gas deliverability in the Enstar local distribution system may fall short of potential demand (at current, relative energy prices) before the year 2010 (ADNR, 2005). The recent Anchorage Chamber of Commerce report (2005), concluded that even if both major Kenai industrial plants were to shut down on or before 2009, that projected remaining demand could exceed projected supply by 2011.

According to an Econ One study prepared for the ADNR (Dismukes, 2002), the economic feasibility of moving gas to the southcentral region depends in part upon future reserve development in the Cook Inlet basin. Study results indicate that spur line throughput must achieve minimum volumes of 30-to-40 bcf per year to generate sufficient economies of scale and be competitive with other energy sources.[37]

A U.S. Department of Energy study of natural gas supply and demand in Southcentral Alaska (SAIC, 2004) concluded that the Cook Inlet Basin is still under-explored, especially offshore and that more discovered reserves would be forthcoming but at higher cost. The study indicated that, while discoveries of smaller fields are more likely, the discovery of large fields is still possible.

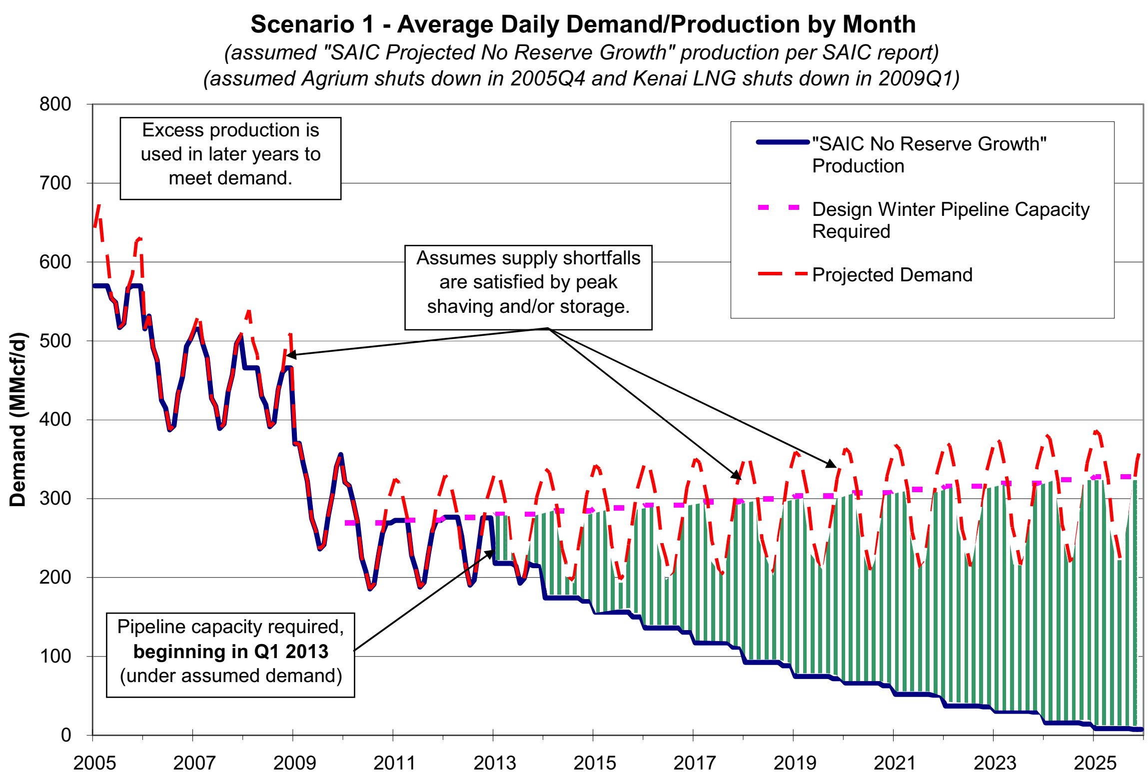
Lukens Energy Group (2004) examined the relationship between declining production rates of existing Cook Inlet gas fields and with the steady progression of energy demand in the southcentral and interior regions. Its analysis indicates that supply shortfalls could occur between 2013 and 2019 even with the potential discovery of 1.5 tcf of Cook Inlet gas reserves. The imbalances initially would involve daily deliverability shortfalls resulting in some amount of expected industrial curtailment similar to that experienced by the Kenai

[37] The preliminary findings of Econ One (Dismukes, 2002) indicate that the levelized cost of a 16- to 20-inch spur pipeline linking southcentral with a major gas pipeline near Fairbanks could be competitive with energy alternatives (such as fuel oil or LNG imports into Cook Inlet) if annual spur line throughput exceeds 30-to-40 bcf per year. This rate is equal to approximately equal to about 100 million cubic feet per day (mmcf/d), about the same as total daily deliveries of the Enstar local distribution system in southcentral Alaska (and about 1/5th of the total Cook Inlet basin gas consumption). The state's proposed share of total ANS gas mainline daily throughput would be about nine times this amount.

ammonia-urea plant in January-February 2006. The study conducted by Northern Economics (2004) for the Alaska Natural Gas Development Authority (ANGDA) also supports these findings.

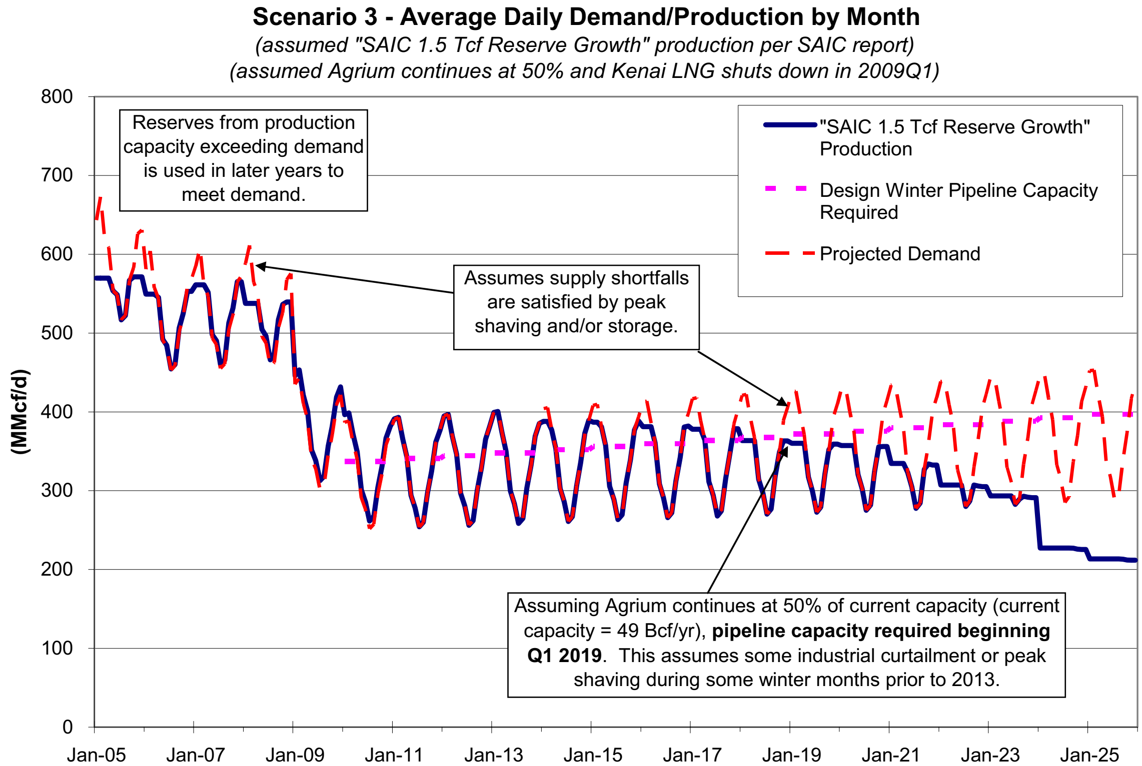
The Lukens Energy Group results are depicted in Figure 19 and Figure 20. Figure 19 is based on the assumption of no additional reserves growth. Here, supply shortfalls beyond those related to seasonal swings would occur beginning first quarter 2013. Industrial plant closures would result in significant demand shifts and would delay the shortfall. Significant 1.5 tcf reserves additions would defer the shortfall several years, depending on the extent of future industrial plant closures (Figure 20).

Figure 19 Projected Daily Cook Inlet Demand and Production, No Reserve Growth with Full Industrial Plant Closures in 2005 and 2009



Source: Lukens Energy Group, June 2004.

Figure 20. Projected Daily Cook Inlet Demand and Production, 1.5 Tcf Reserve Growth and Partial Industrial Plant Closures



Source: Lukens Energy Group, June 2004.

If a Fairbanks to Anchorage spur, or a Glennallen to Anchorage spur were built, this infrastructure would relieve possible future supply constraints that might occur as Cook Inlet natural gas reserves are depleted. The price impact on southcentral Alaska areas already using gas is uncertain. Southcentral gas prices are presently some of the lowest in the nation, although recent gas sales contracts have been tied to prices at Henry Hub, a major natural gas distribution point in Louisiana, which has resulted in southcentral gas prices increasing over time.

In-state ANS gas supplies would likely be priced at the wellhead netback price plus the mileage-sensitive tariff. Whether this price will be competitive with local supplies would depend on the local supply-demand balance. If new Cook Inlet or onshore resources are developed, they might be available at a low enough price to preclude the need for ANS gas. In any case, the option of ANS gas provides both a backstop supply and a ceiling price for southcentral gas. A study conducted for the state by the Lukens Energy Group (2004), indicated that the estimated delivered cost of ANS gas to the Anchorage region would be less than Enstar's current gas supply agreement with Unocal that is pegged to Henry Hub prices. The study further noted that although a more detailed review is needed, the delivered cost is also expected to be less than or competitive with other alternatives for gas delivered into the Anchorage region. The delivered cost of gas into the Anchorage area was based on estimated North Slope netback prices and the cost of transportation on the mainline and the spur line from Fairbanks to the Anchorage region. The study conducted by Northern Economics (2004) for the Alaska Natural Gas Development Authority (ANGDA) also supports these findings.

4.2.5 Natural Gas Liquids and In-State Use

The spur pipeline that provides in-state gas transportation from an off-take point near Fairbanks raises the question of handling NGLs. When gas is produced, a hydrocarbon liquid consisting of a mixture of NGLs gets carried to the surface with the gas stream.[38] In addition to methane, the "rich" ANS gas stream contains relatively high amounts of natural gas liquids including: ethane, propane, butane, and pentane. The significant entrained NGLs content in the gas stream has pluses and minuses for the project.

On the one hand, the rich gas stream may exceed the standard design limits for transmission pipelines. In such cases, either the NGLs must be removed from the gas stream or the pipeline must be built to handle the additional flow-stream mass. The thick-walled, high-pressure, dense-phase mainline system for ANS gas transmission is specially designed to carry this rich gas flow stream. But with very few exceptions, the rich ANS gas stream exceeds the standard design limits for most major North American pipelines that ANS gas will feed into.[39] In order for ANS gas to flow to ultimate market destinations, the NGLs must be removed in order that the gas stream satisfy downstream pipeline, utility, and industrial user specifications for the gas.[40]

On the other hand, NGLs are energy rich and have multiple industrial and petrochemical uses. NGL extraction and trading are valuable business opportunities. Enormous petrochemical complexes and pipeline systems are strategically located near major regional centers for NGL extraction. Investments in these industrial facilities would not have come about if the NGLs were nothing more than residual byproducts. Because they compete with products refined from oil, butane and propane prices are a function of crude oil prices, as well as natural gas prices. These components almost always sell at a heat-equivalent premium to methane.

Extracting NGL components from the gas stream requires a two-step process of (1) removing the "raw mix" of liquids from the gas stream at gas processing facilities typically located near the gas wells, then (2) separating the liquid mixture into various constituent elements—ethane, propane, butane, pentane, and other components—in a fractionation facility. Extraction and fractionation are capital intensive. The sponsor group proposed project design includes a $690 million NGL plant partly for product design specification purposes and partly because the NGL components are themselves inherently valuable.

These NGL co-products have commercial value both as primary energy products and as feedstock for numerous intermediate industrial and petrochemical product applications. For

[38] Some gas fields, such as those in the Cook Inlet Basin of South-central Alaska produce "dry" gas stream that consists primarily of methane with few additional hydrocarbon components. Dry gas reduces handling processing requirements. Cook Inlet gas consumers burn raw gas direct from the well bore except for treatment with an odorizing agent.

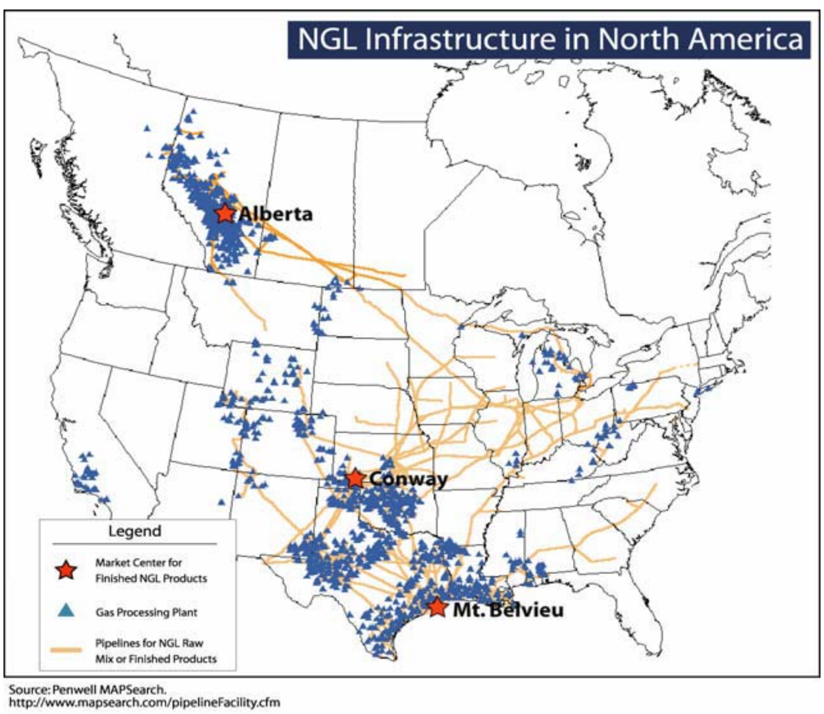
[39] The Alliance Pipeline that began operating in 2001 from Western Alberta to Chicago is a high-pressure, dense-phase pipeline designed to carry NGLs.

[40] ANS gas also contains carbon dioxide and sulfur dioxide. These contaminants are to be largely removed at the gas treatment plant before the gas enters the mainline.

example, ethane is the feedstock for ethylene, a major building block for chemicals and plastics. It is also used as a solvent for enhanced oil recovery. In addition to its use in space and water heating and cooking, propane has large-scale industrial heating uses, as well as uses in petrochemical, agricultural, and transportation. Butane also has numerous industrial uses including blending agent for heavy oil pipeline transportation, octane enhancer for motor gasoline, and for production of vinyl acetate.

Over the past several decades, major North American regional trading and industrial centers have grown around the NGL business. With over 600 NGL field plants for raw mix removal, six major straddle plants, and several dozen central fractionation facilities, Alberta is a significant regional hub in the North American NGL industry. Total capacity for NGL recovery in Alberta is about 650,000 barrels per day. Straddle plants account for about 40 percent of this total.[41] Most of Canada's petrochemical industry is ethane-based and located in Alberta. Natural gas production from conventional sources in the WCSB is expected to remain flat and eventually decline over the next two decades (NPC 2004). Non-conventional natural gas from coal and other sources contain minimal NGLs. Consequently, new sources of NGLs, such as ANS gas, could serve the industrial and petrochemical products markets in Alberta. In addition to Edmonton, Alberta, the other major North American NGL trading centers serving various regional markets are: Conway, Kansas; Mont Belvieu, Texas; and Sarnia, Ontario (not shown) (Figure 21).

Figure 21. NGL Infrastructure in North America



Source: Dismukes, 2002.

[41] Straddle plants are located adjacent to (or straddle) natural gas transmission pipelines. These facilities typically operate both process steps: extraction and separation, for multiple NGL product removal and sale.

Irrespective of where ANS is consumed, NGL extraction ultimately will be necessary and potentially highly profitable. One option would be to construct a large-scale NGL extraction and fractionation plant at an off-take point near Fairbanks in interior Alaska, possibly in conjunction with a lateral spur pipeline designed to deliver ANS gas to in-state markets. The economic potential for a NGL plant and/or a petrochemical facility, would depend on many factors, including: oil and gas prices, NGL prices and costs, including product transportation and access to markets. Normally, large NGL facilities are built in proximity to petrochemical facilities that use the NGLs. Muse Stancil (June 2004a) studied this question and concluded that, while certain advantages for petrochemical complex development in Fairbanks could be present (availability of attractively priced feedstock, water-borne access to California markets, and synergy with other potential energy developments such as cogeneration of electric power), these advantages would be offset by significant disadvantages, including:

1) variability of gas composition over time and problems with optimal sizing,
2) inefficiency of processing large amounts of gas twice—first at Fairbanks and again in Alberta,
3) non-optimal sizing of the mainline system downstream of Fairbanks,
4) higher capital and operating costs than in other competing locations,
5) lack of supporting infrastructure, and
6) lack of supporting markets for byproducts.

In sum, the large-scale petrochemical complex at Fairbanks would be unlikely to satisfy basic economic thresholds. Any advantage in low feedstock costs probably would be overwhelmed by technical, efficiency, cost and transportation factors.[42]

An alternative would be to construct a small-scale NGL extraction and fractionation facility designed, in conjunction with a spur pipeline, to serve local and regional in-state markets for certain NGL components such as propane. One option would be to simply extract the NGLs with a straddle plant at the off-take point and infuse the NGL raw mix back into the mainline flow-stream, possibly after partial propane and/or ethane separation for local specialty, petrochemical operations. But returning the raw mix to the gas stream would further enrich the entire mainline flow-stream destined for Alberta and could push it closer to its dense-phase operating limits. Further economic and engineering study of variations to this option is currently underway in separate evaluations by ANGDA and AGPA. At a minimum, ANS gas off-take at an intermediate point near Fairbanks would require NGL extraction, either at the point of off-take or further downstream at port facilities in Valdez or in Cook Inlet. The NGLs either would be disposed via in-state uses or exports, or put back into the mainline gas stream. In-state LPG (propane and butane) consumption has historically ranged from 600 to 900 barrels per day (Muse Stancil, October, 2004b).

The Muse Stancil (June, 2004a) study will not be the last word on the feasibility of an NGL plant in Alaska. The project must conduct a feasibility study of NGL processing

[42] In 2001-02, Williams Bros. Inc. examined the commercial potential for a large-scale polyethylene pellet manufacturing facility near Fairbanks with rail and ocean transport to Pacific Rim markets. While their conclusions were never shared publicly, the company has not pursued this opportunity further.

opportunities in Alaska before the commencement of the initial open season (see Article 9.5). If a NGL plant is feasible in Alaska, that is, if any participant decides to build one, then the state reserves a 20 percent ownership interest in that plant.

The sponsor group project presumes a large-scale NGL plant either in Alberta or in the Lower-48 and does not contemplate large-scale NGL extraction in Alaska. An NGL plant in Alaska would be a major departure from the existing project scope and design.

4.2.6 In-state Distribution

The state's concerns about ensuring access to the pipeline for needs within Alaska were addressed in three ways. Working with the U.S. Congress, the state made sure that the ANGPA created special provisions directed at in-state service. First, ANGPA requires that a pipeline project study in-state needs, "including tie-in points along the Alaska natural gas transportation project for in-state access" (Section 103(g)). Second, ANGPA requires that the commission provide for "reasonable access" to the pipeline for transportation of royalty gas of the state "for the purpose of meeting local consumption needs within the state" (Section 103(h)). Third, in section 109, ANGPA confirms that a lateral (spur line) from the mainline serving in-state needs shall be regulated by the RCA, not FERC. Section 109 also states that FERC will consult with the state regarding mainline rates that transport gas for delivery within Alaska.

FERC built upon this foundation in the open season regulations. FERC requires the pipeline to offer an intrastate transportation rate in the open season and in its tariff, based on mileage, separate and apart from any interstate rates. The intrastate rate is to be constructed without reference to costs to make deliveries outside of Alaska. Second, FERC requires the pipeline to propose in-state delivery points as determined by the required study of in-state needs. The pipeline must also include an estimate of how much capacity will be used in state (18 CFR Section 157(b) and (c)(1),(8), and (14)).

In turn, the contract sets a timetable for the pipeline to complete its study of gas consumption needs and offtake points in Alaska and requires consultation with the state on the location of these off-take points. The contract requires the pipeline to pay for facilities at four offtake points. It confirms that in the open season, the pipeline will offer mileage sensitive service and offer segmented capacity to facilitate in-state service. The contract requires the pipeline to cooperate with any person wanting to connect facilities to the pipeline for in-state service. The contract also requires the mainline entity to conduct a study of NGL processing opportunities in Alaska before the open season. Alaska will gain useful knowledge of the feasibility of processing natural gas liquids in Alaska because of this study.

As part of a comprehensive set of provisions for in-state service, the contract ensures that intra-state gas pipelines can be built by interested third parties. As the project advances, the dimensions of the need for service within Alaska should become clearer and planning is already underway to identify the best means to satisfy that need.

4.2.6.1 Identification and Selection of Off-take Points for In-state Needs

The contract specifies that the in-state connections where gas could be taken from the mainline (i.e., off-take points) and the mileage-sensitive tariffs for deliveries to those points will be provided to facilitate firm contract deliveries to in-state gas off-take points such as Delta Junction and the Fairbanks North Star Borough. The location of the off-take points has not yet been established. The selection by the state of these in-state off-take points will be guided by a study of natural gas consumption needs and prospective in-state off-take points.[43] The location of each potential gas off-take point would be in part driven by market forces and demand for natural gas. FERC could also require in-state off-take points in addition to the four selected by the state.

The construction of off-take points would make it possible to provide natural gas infrastructure to areas which are not currently served by natural gas. This gas could be used for commercial, industrial, and residential heating needs as well as for additional electricity generation capacity. It would be the responsibility of the end users of the natural gas or local utility companies to provide the entire infrastructure needed to process and deliver the natural gas downstream of the main line. In addition, in-state off-take points would provide the opportunity for the sponsor of a liquefied natural gas project or an in-state petrochemical project to arrange contracts for the delivery of natural gas. The cost-competitiveness of ANS gas vis-à-vis the coal, wood, and fuel oil alternatives currently in place is not certain. Nevertheless, the option of supplying in-state areas with ANS gas provides a backstop for the current energy resources now in use in the northern railbelt.

Spur lines from Fairbanks to Anchorage, as well as from Delta Junction to Glennallen, Anchorage, and Valdez are under consideration.[44] As discussed above, although these spur lines are not addressed in the contract and would not be a part of the project, they would enable delivery of ANS natural gas to the existing southcentral natural gas distribution grid.

4.2.6.2 Purchase of Gas

The mainline entity[45] will not own natural gas transported in the pipeline. Any natural gas shipper, including the State of Alaska, may choose to sell and supply gas to in-state users. Sales agreements will likely require long-term purchase commitments by in-state users.

4.2.6.3 Initial In-state Volume and Rates

During the initial open season, the mainline entity will receive firm commitments from potential shippers to purchase capacity for the shipment of natural gas to points on the proposed pipeline. The producers will bid for capacity on behalf of the state. This is advantageous for the state since the producers have better economic and supply information for each field or unit. The state has the right to make separate capacity commitments to cover

[43] FERC requires the mainline entity to either complete the study or adopt a study that, "if practicable", includes or consists of a study conducted, approved, or otherwise sanctioned by an appropriate governmental agency, office or commission of the State of Alaska (§ 157.34(b) FERC Order No. 2005 Final Rule, issued February 9, 2005). The study of natural gas consumption needs and prospective in-state off-take points would be completed or adopted at least thirty days before the mainline entity files its initial plan to accept bids from shippers for the use of the new pipeline's capacity with the FERC.

[44] Alaska House Bill 254 would provide $8 million of Railbelt Energy Funds to plan for natural gas spur lines from the proposed mainline from Delta Junction to Glennallen and Valdez or from Fairbanks/Nenana to Anchorage via the Parks Highway route. <http://www.legis.state.ak.us/basis/get_bill_text.asp?hsid=HB0254A&session=24>

[45] The proposed mainline entity is Alaska Gas Pipeline Company, LLC (AGPC); see Section 8 for additional information. The mainline entity will own the line pack.

in-state access to the gas without giving up its right to have the producers take the lead in the bidding process. The mainline entity will make its final decisions about the design of the pipeline based upon firm commitments received from shippers during the initial open season. These commitments to purchase pipeline capacity will be partially based on estimates of the costs of building and operating the pipeline ("cost of service") that must be provided by the mainline entity when it files a notice with FERC for the initial open season.[46]

FERC also requires estimated unbundled transportation rates for each in-state off-take point to be posted when the mainline entity files its notice for the initial open season.[47] As noted above, the contract requires the mainline entity to offer mileage sensitive rates to in-state off-take points including the Fairbanks North Star Borough and Delta Junction.

Once actual construction and financing costs are known and shortly before the pipeline is to begin operation, FERC will review and approve the initial cost-of-service rates for the pipeline. FERC typically requires that a new pipeline file a rate case within three years of beginning operation and that practice should be followed here. In certain circumstances, shippers or prospective shippers may also initiate a challenge to the rates being charged by the pipeline. Under the commission's negotiated rate policy, however, "shippers and the pipeline are free to make an agreement to dispense with cost of service regulation and agree to any mutually agreeable rate" [48] (FERC, 2005). If spare or unused capacity is available, a potential shipper can pay the cost-of-service (recourse rates) or try to negotiate a rate with a capacity owner. Negotiated rates are posted by FERC and may be considered a maximum rate during a rate case. If no excess capacity is available, a potential shipper can attempt to negotiate with a capacity owner to move natural gas on the pipeline.

If commitments are made for in-state delivery of natural gas during the initial open season, the mainline would be sized to accommodate this in-state demand and rates would be established by FERC. However, if no firm commitments are made for in-state delivery during the initial open season, FERC requires cost of service rates be established for the off-take points. [49]

4.2.6.4 Changes to In-state Volume and Rates

Once the pipeline is built, a new shipper or a shipper desiring to increase the volume of gas delivered to an in-state off-take point could purchase excess pipeline capacity, if it exists, and pay either the recourse rate or attempt to negotiate a rate. If excess capacity is not available, the shipper can attempt to negotiate with an existing capacity owner to obtain delivery of the gas and would likely pay a negotiated rate.

If a capacity owner agrees to change deliveries in, or increase shipments to, Alaska off-take points, Article 9.4 of the contract requires the changes or new arrangements not shift costs to the holders of pre-existing shipping commitments or create excess pipeline capacity unless

[46] § 157.34(c)(7) FERC Order No. 2005 Final Rule, issued February 9, 2005

[47] § 157.34(c)(6) FERC Order No. 2005 Final Rule, issued February 9, 2005

[48] "Negotiated rates can be used to lock in transportation costs and pipeline revenues to the mutual benefit of both the shippers and the pipeline, without the risks of later changes to rates and revenues under the NGA." Order 2005-A at p. 30.

[49] § 157.34(c)(6) FERC Order No. 2005 Final Rule, issued February 9, 2005

mutually agreed by all affected parties. For example, if the state decided to shift deliveries of gas from Alberta to an in-state off-take point, the state would still be responsible for that portion of costs for providing the capacity to deliver the volume of diverted gas from the off-take point to Alberta. The state could avoid this cost if it found additional gas to ship to Alberta, or if the in-state purchaser agreed to reimburse the state for unused capacity charges from the in-state off-take point to Alberta. In a second alternative, the pipeline could be expanded, within reasonable parameters, to accommodate the increased in-state flows if incremental gas was available to ship on the line. The preceding example illustrates a situation that might occur if potential, major in-state users are not ready to contract for natural gas during the initial open season or before the design of the pipeline is finalized.

Article 8.7 of the contract establishes procedures to expand mainline capacity if a need is demonstrated and prospective shippers satisfy the credit standards of the existing tariff contract and are able to fully cover the capital cost of the expansion without impacting the recovery of costs from existing facilities. If, for example, additional gas were available on the North Slope, it might be possible to add compressors and increase the flow of natural gas to meet an increase in demand of in-state natural gas users after the pipeline is built. However, such an increase would require both an expansion of pipeline capacity and greater production of natural gas.

4.2.6.5 Movement of Gas from Off-take Points to In-state Users

Delivery of gas beyond an in-state off-take point would require investment in local gas conditioning and distribution infrastructure (e.g., pressure reduction equipment, calorific control equipment, spur lines, local gas distribution systems, etc.). As specified in Section 108(a) of ANGPA, regulation of downstream facilities in Alaska would be the responsibility of the RCA. Construction and operation of such facilities will not be the responsibility of the mainline entity.

ANGDA and Enstar are both evaluating spur line concepts to take natural gas from the mainline and make gas available to in-state users that are in proximity to the pipeline, as well as transport the gas to markets in southcentral Alaska. Enstar is considering a spur line from Fairbanks that would parallel the Parks Highway to Palmer, and ANGDA is considering a spur line from Delta Junction or Glennallen that would follow the Richardson Highway and Glenn Highway corridors to Palmer (See Section 5 for additional information on the ANGDA proposal).

4.3 Future Explorers Must Have Access to the Gas Pipeline

Exploration and development opportunities for new market entrants are critical for Alaska's future and without access to the gas pipeline there may not be enough new explorers and exploration activity to find the gas resources that are necessary to fully operate the pipeline for the 35-year contract term. In addition, these new explorers should have the opportunity to have the same fiscal terms as the sponsor group in order to enable them to compete for lease sales on the ANS. This section describes the conditions that provide access to pipeline capacity and fiscal certainty.

4.3.1 Explorer Access to Capacity

A prominent concern of explorers not affiliated with the pipeline has been their ability to ship gas they discover on a pipeline that is owned by the sponsor group. They have concern not only with respect to fair access in the initial open season on the pipeline but also with respect to shipping gas that may be discovered years into the pipeline's life. If the pipeline is fully subscribed by the successful bidders in the first open season who are more likely than not to be those companies that control the vast majority of known ANS gas resources, it is important that explorers have assurance that the pipeline will be expanded to accommodate their gas. Access to pipeline capacity will provide incentive for explorers to find and develop additional gas resources.

4.3.2 Fiscal Certainty for Explorers: Uniform Upstream Fiscal Contract

The state believes that the contract benefits for the sponsor group should also be available to other North Slope leaseholders. The reason for this is that more gas needs to be discovered and developed to fill the pipeline to capacity during the term of the contract. As noted in Section 1.2, there are about 35 tcf of identified resources that will support the project but a total of 59 tcf is needed to fill the pipeline to capacity for 35 years. Additional gas resources would strengthen the project, enable an expansion, and provide more revenues to the state.

For all of these reasons, the state will propose legislation that would create a level playing field for explorers and producers not affiliated with the project with the objective of attracting more gas to the project. The legislation would authorize the commissioner of revenue, after consulting with the commissioner of natural resources, to develop a uniform upstream contract. This upstream contract would include provisions identical in substance to numerous key provisions of the contract and would require that signatories to the contract agree to work commitments requiring diligent exploration efforts and to making firm transportation commitments for the shipment of gas that results from their development efforts.

The contract contains a list of all of the oil and gas leases which may produce gas or oil that are entitled to fiscal certainty under the contract. The contract provides that new leases may be added if a sponsor obtains the lease at a state, federal, or private lease sale. Property acquired at a state lease sale must be removed from the contract and lose fiscal certainty if the lease does not deliver gas to the gas line within 15 years. Property acquired at a federal or private lease sale has 20 years to deliver gas to the gas line.

A person who is not a sponsor may obtain fiscal certainty on an oil or gas lease located on the ANS not listed in the contract by agreeing to be bound by an upstream contract applicable to the lease. Under this contract, the person would obtain substantially similar fiscal certainty terms as those applied to the sponsors. The person must enter into a letter of intent to make a firm commitment for transportation of gas that is discovered from the lease on the project. If the contract with the sponsors is terminated, the upstream contract would terminate as well. The ability to enter into an upstream contract lasts until a total of 70 trillion cubic feet of gas has been committed to the project and 70 trillion cubic feet of gas has been delivered or has reasonably become available for delivery to the project. In addition, the authority of the commissioners of revenue and natural resources to jointly execute such contract would expire once 70 tcf has been committed to the project[50].

4.4 The Gas Pipeline Must Be Expandable

New discoveries must get to market so Alaska realizes maximum benefit from the gas pipeline. As noted in Section 1.2, Alaska's potential gas resources may exceed 200 tcf, a huge increase over the level of known resources. With increased exploration activity it is likely that additional commercial resources will be discovered and the pipeline must be capable of expansion to achieve maximum benefit for the state and its residents.

Expansion issues have been addressed in three ways. Section 105 of ANGPA gives FERC the power to order expansion of an Alaska gas pipeline if certain conditions are met and special procedures followed. FERC also addressed some expansion issues in the open season regulations. Finally, the state negotiated a special expansion article in the contract that created rights for the state to initiate an expansion if a person is unable to secure capacity from other shippers or the pipeline or through a voluntary expansion by the pipeline entity (Article 8.7 of the contract).

FERC's new authority to order expansion in certain circumstances has been described above and will not be repeated here. Because it is new, one cannot know how the FERC will interpret and apply its new powers. In its open season regulations, the FERC has said that as part of its pre-certification review of the project design, it will consider the extent to which a proposed project has been designed to accommodate "low cost expansion" and may require changes in project design as needed "to promote competition and offer a reasonable opportunity for access to the project" (18 C.F.R. § 157.37). In the open season orders, FERC reversed its lower 48 policy and established a presumption favoring rolled in rates for any expansion. This is thought to encourage expansion by making sure expansion shippers will not pay a higher rate than existing shippers (18 C.F.R. § 157.39). The FERC regulations also establish that the FERC will review whether those who obtain capacity in expansion open season are established or new shippers on the pipeline and may order changes for competitive reasons (18 C.F.R. § 157.36).

Despite these competitive safeguards, the state sought additional protection because of its concern for independent exploration. It successfully negotiated an additional expansion clause. Article 8.7 lays out a special process for state initiated expansions. If any person, including the state, is unable to obtain expansion capacity either from another shipper or from a voluntary expansion of the pipeline by its owners, the state may issue an expansion notice to the owners of the pipeline that ultimately requires them to file an expansion application at the FERC provided certain conditions are fulfilled and processes followed (See Section 4.4.3).

With this clause, those interested in expansion have three remedies. They have the protective provisions that the FERC built into the open season regulations. They have the right to go to FERC to obtain a mandatory expansion based on the new powers granted in section 105 of

[50] The 70 tcf amount is an estimate of the total amount of gas that would be needed if the project were to be expanded to transport approximately 5.5 bcf/day for 35 years.

ANGPA. They also have the right to have the state act in their stead as provided in Article 8.7 of the contract.

4.4.1 Expandability of Base Design

There are two ways in which gas pipelines can be expanded to increase their throughput—by adding compression or by looping. Additional compressors can be added at existing or pre-arranged compressor sites. The additional capital required is comparatively small but additional fuel is required to power the new compression. Looping or "twinning" as it is sometimes called involves adding additional segments of pipe between compressor stations. This is more capital intensive.

The initial design capacity of the project is for a throughput of 4 to 4.5 bcf/day. The sponsor group has indicated that their preliminary design contemplates that the pipeline can be expanded relatively inexpensively through additional compression. The additional compressors would enable throughput of approximately 6 bcf/day. Additional capacity would require looping. From an engineering perspective, it is optimal to design for expansion when the base design is undertaken. There are complicated engineering trade-offs between fuel and capital cost that must be undertaken to optimize the design for expansion. In arriving at a design that allows for compression expansion to near 6 bcf/day, the sponsor group appears to have addressed the potential need for low cost expansion.

The project summary describes a gas pipeline that is designed to accommodate relatively low cost expansion. The sponsor group made a preliminary decision to build a gas pipeline 52 inches in diameter with an operating pressure of 2,500 pounds per square inch. A high-pressure line of this diameter requires exceedingly strong steel and thick walls. The pipeline construction methods for a smaller 48-inch line are well-established, but building this 52-inch, thick-walled line will require special steel mills to fashion the pipe, and specially-made pipe-laying and welding equipment to construct the line. Building a 52-inch line is riskier and more expensive[51] than building a smaller line, and for this reason the pipeline companies that state officials talked to said that they would build a smaller-diameter line. Not so the sponsor group. They were willing to take this 52-inch risk in order take maximum advantage of the economies of scale associated with gas pipelines.[52] This large-diameter pipeline not only allows a large volume of gas to be transmitted through the line while limiting fuel loss, it also allows for a relatively inexpensive and attractive large increment of expansion. In fact, the average capital cost per unit decreases for an almost 50 percent expansion of the line. This decreasing cost function means that expansions not only will be in the pipeline entity's best interest (through more tariff revenue), but will also benefit existing shippers as well as

[51] There are additional risks to building a large volume pipeline. The sponsor group faces the market risk of placing four bcf/day of additional gas supply into the North American market at one time. They also face the reserve risk that comes from rapidly depleting the known gas resources. After 16 to 20 years, gas production rates from known gas resources will begin to decline, and the pipeline will have empty space unless more gas is found. The sponsor group appears to have made the decisions on pipeline diameter, grade of steel, and other new technologies in a calculated risk to make a challenged project work. They apparently thought that they had to go beyond the traditional 48-inch gas pipeline to make the project a reality.

[52] The pipeline's design is one targeted to move gas off the North Slope that would otherwise remain there. The high operating pressure of the line allows NGL components (ethane, propane, and some butane) to be transmitted in the line, components that, being too light and vaporous to be sent down TAPS with the oil, would remain trapped on the slope.

expansion shippers through lower per-unit tariffs. Apart from the FERC access regulations, or the SGDA contract provisions, the 52-inch decision is a concrete way of telling explorers that if the gas is there, the pipe capacity will be there to take it to market.

As part of these regulations, the commission has addressed competitive issues that might arise from an improperly sized pipeline or a pipeline that was not capable of expansion to take new shippers (i.e., competitors to the production companies affiliated with the large North Slope producers). The open season regulations state that “the Commission will consider the extent to which a proposed project has been designed to accommodate the needs of shippers who have made conforming bids during the open season, as well as the extent to which the project can accommodate low-cost expansion, and may require changes in project design necessity [sic] to promote competition and offer a reasonable opportunity for access to the project.” 18 C.F.R. Section 157.37. If an expansion is proposed, “the Commission will consider the extent to which the expansion will be utilized by shippers other than those who are initial shippers on the project and, in order to promote competition and open access to the project, may require design changes to ensure [access].” 18 C.F.R. Section 157.36.

4.4.2 Voluntary Expansion

A pipeline expansion might result from three different avenues. They are voluntary expansion by the owners of the pipeline, a state initiated expansion arising from specific provisions of the contract, and mandatory expansion under the ANGPA. In this and the following two subsections, these processes will be described. It is important to recognize that under any of the above provisions, a pipeline cannot be expanded without the prior approval of the FERC.

In the lower 48 pipeline industry, expansion decisions are made by the owners of the pipeline. As pipeline owners, they have an incentive to attract shippers to fill their pipe. If there is a potential to attract additional shippers through expansion of the pipeline, then the owners will conduct an analysis to determine the best way to add capacity. As indicated above, capacity may be added through additional compression or by looping.

The LLC for the mainline contains a procedure for the members of the LLC to determine whether to expand it. Any member of it may deliver a written proposal for a proposed expansion. There follows a sequence of steps beginning with a management committee vote on whether to conduct a feasibility study, followed by the preparation of such a study, and then a decision on whether to proceed with a FERC application for expansion authority. If and when an expansion is authorized by the FERC, the steps to accomplish the expansion are laid out.

The sponsor group asserted that the owners of the pipeline will have a natural incentive to expand the pipeline if sufficient customer support is shown. They argue that expansion throughput provides additional profit to them from pipeline operations. There is an opposing school of thought, however, that the owners of the pipeline may have an incentive to control expansion to favor their affiliate production and restrict competition. The merits of this argument from an antitrust perspective are addressed in Section 4.7.7.3 below.

4.4.3 ANGPA Mandated Expansion

Section 105 of ANGPA of 2004 gives the FERC the power to order the expansion of an Alaska gas pipeline after notice and an opportunity for a hearing subject to satisfaction of a number of carefully delineated conditions and procedures. Any person can initiate the expansion process. The commission then must satisfy conditions that the rates for the expansion service are designed to ensure the recovery of the costs associated with the expansion whether those rates are incremental to, or rolled in with, existing rates, that those rates do not require a subsidy by existing shippers, that the expansion be consistent with the terms and conditions of the existing gas pipeline tariff, that the expansion not adversely affect the financial or economic viability of the project nor its overall operations, that the contract rights of existing shippers be protected, and that adequate downstream facilities to deliver gas to market exist or are expected to exist. Finally, any expansion order issued by the Commission under Section 105 is void unless the person requesting the order executes a firm transportation agreement within such reasonable time period as the Commission shall determine.

The enactment of Section 105 assures shippers that they have a remedy at the FERC should the pipeline refuse or resist expansion. Because the statutory provision is new and untested, it is uncertain how a future FERC will chose to interpret and apply the requirements of Section 105. Nonetheless, the fact that it exists provides a backstop to independent shippers in any negotiations for a voluntary expansion.

4.4.4 State Directed Expansion

Even though Section 105 of ANGPA of 2004 gives the FERC unique authority to order expansion of an Alaska gas pipeline, the state sought additional protection because of its concern for independent exploration. Article 8.7 lays out a special process for state initiated expansions. If any person, including the state, is unable to obtain expansion capacity either from another shipper or from a voluntary expansion of the pipeline by its owners, the state may issue an expansion notice to the owners of the pipeline that ultimately requires them to file an expansion application at the FERC provided certain conditions are fulfilled and processes followed.

The state's option can be exercised no more frequently than every five years. The expansion must be of a minimum size depending on whether it is for the mainline and GTP (125,000 mmBtu of capacity per day) or a gas transmission pipeline (50,000 mmBtu). Each number does not count any sponsor’s volumes. The expansion is confined to the mainline and does not apply to an in-state lateral, nor can it require looping in excess of 100 miles. The proposed expansion shipper must be creditworthy, pay in advance the costs of preparing and filing the expansion application, and must participate in an expansion open season.

There are also rate requirements for the expansion that are designed to protect both the expansion shipper and existing shipper interests. These generally mirror the balance Congress struck in the mandatory expansion language of ANGPA. Any disputes arising under this clause will be resolved under the dispute resolution provisions of the contract.

4.5 The State Should Own a Share of the Pipeline

State ownership will create economic benefits for the state through providing a stable, steady revenue stream. As a member of the limited liability corporation or other entities (LLC) that own the pipeline, the state pipeline company will participate in decisions related to project development (see Sections 8 for ownership structure). The state's participation will advance the project by reducing the magnitude of the investment the producers will make in the project thereby making the project more economically competitive with other projects in their global project portfolios (See Section 5.1).

State ownership alone does not entitle the state to ship its gas on its share of the pipeline, nor will the state own a segment of the gas pipeline capacity that it can independently offer for bid. All of the gas pipeline's capacity will be offered by the mainline entity (which the state would be a member of) to potential shippers during the open season, and neither the state nor other members of the pipeline corporation has preferential rights to any capacity. Thus, owners of a pipeline must award capacity rights to bidders in a public open season process that is overseen by FERC. In the case of the Alaska gas pipeline, as required by Congress, FERC has adopted a comprehensive set of regulations that apply to the project's open season. The state and every other prospective shipper must bid for rights to capacity on the pipeline.

4.5.1 Purpose and Concerns on State Ownership

Ownership of the mainline and other facilities involves investing in a multi-billion dollar project, sharing in the project risks, and benefiting from the returns on investment. The benefits and risks of state ownership are discussed in more detail in Sections 5.1 and 6. The following presents a brief discussion of the rationale for state ownership, some concerns regarding state ownership, and an analysis of the revenues from equity investment in the pipeline project.

The state believes that ownership of the pipeline, and sharing of the subsequent risks that occur with ownership, is necessary:

- to improve project economics to a point that the Alaska natural gas pipeline project becomes an economically competitive option in the project portfolios of BP, CP, and EM,
- to provide a stable revenue stream to the state from a return on the state's investment, and
- to expedite construction of a natural gas pipeline.

In addition, the Joint Committee on Natural Gas Pipelines (Joint Committee to the 23rd Legislature, 2002) and others have noted that state participation would mean:

- acquiring greater control over its destiny and resources;
- making a good investment for the state;
- reducing risks for industry and thereby encouraging the project to move forward; (Portman, 2005.) and

- reducing the state's exposure to commodity price risk because cash flow from the pipeline and other facilities will be more certain and less volatile than the state currently experiences with oil revenues. (Office of the Governor, 2004)

There are also some major concerns related to state ownership. While state ownership is expected to generate stable state revenues over the life of the project, it also involves a number of risks. These risks are fully discussed in Section 6.

Some have expressed concern that state ownership of the pipeline could create a conflict of interest in the regulatory, environmental, and tax areas. These concerns are addressed in several ways. The state's interest in the pipeline will be owned by a separate state corporation with an independent board of directors. State environmental policy and enforcement will be the responsibility of the Department of Environmental Conservation which will pursue its responsibilities according to law. The state pipeline company will not control or influence those responsibilities.

The state will also be the marketer of all of its gas. As such, it will be free to pursue at the FERC or NEB tariff policies that provide the best return for its gas. From this perspective, it will be in the same position as or "aligned with" the sponsor group that own and will own both pipeline and production interests.

One relationship will change. Currently, for oil and gas production taxes and royalty taken in value, the producers have an incentive to seek higher tariffs as a way of lowering the wellhead value on which royalty and tax payments are based and reducing those payments. Under the contract, this incentive will be removed. Royalty obligations and tax obligations will be paid in gas with the payments determined, respectively by the lease terms and as a fixed percentage of gas measured at a reference point. The state will no longer be in a derivative position to the producers on royalty and tax values. Instead, it, like they, will directly market ANS gas and will seek the best transportation and price terms that it can find.

The argument also has been made that the state would effectively have no more control over the gas pipeline tariff with a minority ownership position and a limited ability to influence the mainline entity's position on tariffs. Since FERC would regulate the interstate tariffs, and the state would have access to information as part of the FERC process, some argue that it is unlikely that the state would gain any more control over the gas pipeline's tariff as a business partner than as a participant in the FERC proceedings.

As a member of the mainline entity, the state's LLC member would be entitled to participate in the process by which the mainline entity decides the tariff that it would propose to the FERC. Accordingly, the state, through its LLC member, will have an early opportunity – before the FERC is ever involved—to argue for the tariff that it wants, and to participate in the discussions on the tariff inside the mainline entity. The state believes there is definite value in these rights although they may not amount to absolute control. These rights as an LLC member are in addition to the rights that the state has as a prospective shipper of natural gas to protest the tariff and intervene in tariff proceedings once the FERC process is started. In addition, because of its seat at the table of the mainline entity, the state will participate in the major decisions of the mainline entity regarding planning, engineering, construction, and operation.

4.5.2 Advantages of State Ownership

Advantages of state ownership are related to economic benefits, participation in project development decision-making process, and making the project more attractive from the producers' perspective.

Economic benefits will accrue because the state will receive a proportionate share of the earnings of the pipeline. Because shippers will have signed binding long term contracts to ship their gas on the pipeline, the pipeline's earnings and the state's share thereof will be largely independent of the market price of gas. Thus, the state will achieve downside protection on part of the revenues of the gas project by owning a share of the pipeline. FERC will establish the rate of return that the project will earn on its equity investment based on its assessment of the risks of the project and market conditions. According to recent FERC cases, it is anticipated that an after-tax return will be in the order of 14 percent on equity. Section 3.1 discusses the contract terms with regard to state ownership, while Section 4.1 describes revenue potential related to state ownership, and Section 6 describes the economic and financial risks inherit to ownership of gas and project components.

Through a state owned gas pipeline company, the state will be a member of the limited liability corporation (LLC) or other entities that own the pipeline, the treatment plant, gas transmission lines and other elements of the project. The representatives of the state pipeline company will participate in decisions relating to the development of the project on generally the same basis as other participants. Thus, the representatives of the state pipeline company will have access to information about project development, preparation of the FERC and other permit applications, including the proposed tariff, and procurement and construction. The representatives of the state pipeline company will have a voice and a vote on the major decisions that the pipeline management committee will face. Details of state ownership are provided in Section 3.1.

The state's participation will also materially advance the project by reducing the magnitude of the investment the producers will make in the project, thereby reducing their risk and increasing their internal rate of return. This topic is discussed further in Section 5.1. In simple terms, the producers will not have to invest in building pipeline capacity that is larger than their anticipated share of gas they will ship through it. Broadly speaking from an economic perspective, the state will invest in the amount of pipeline capacity that is needed to ship its gas and the producers will invest in the corresponding share that is needed to ship their gas.

4.5.3 Taking Capacity on the Pipeline

The commitment by the state to market its gas, and to take capacity on the pipeline and related facilities, reduces the up-front capital expenditures by the sponsor group and reduces the level of firm transportation commitments they must make. These two items increase the internal rate of return for the sponsor group and reduce their risk, thus making the project more attractive compared to other investment options, and therefore increases the chances that the pipeline project moves forward.

Prospective owners of natural gas pipelines obtain financing when the shipper (the owner of the gas moving through the pipeline) makes a long-term commitment to the carrier (pipeline owner) to pay the tariff to ship a fixed amount of gas regardless of the price of gas or whether there are sufficient known gas resources for the long-term commitment. Such a commitment is also necessary to get a FERC certificate to build the pipeline. These long-term commitments are called firm transportation agreements, and generally have a term of 15 to 20 years.

These firm transportation agreements are considered liabilities to the shipper. Liabilities are defined as "probable future sacrifices of economic benefits arising from present obligations of a particular entity to transfer assets or provide service to other entities in the future as a result of past transactions or events." (Financial Accounting Standards Board, 2000)

Such liabilities may not appear on the balance sheet of the shippers. Per Generally Accepted Accounting Procedures (GAAP), whether a debt goes on the balance sheet or not depends on whether the length of the commitment exceeds 75 percent of the estimated economic life of the asset, or whether the present value of the payments exceed 90 percent of the fair value of the asset.

In the case of a pipeline that may have a long life, or several subscribers, those criteria may not be met. In that case, the commitment is considered an "off-balance sheet" long-term liability. Whether it is "on" or "off" balance sheet debt is irrelevant; it is still debt. Forms of off-balance sheet obligations include operating leases, purchase obligations, project financing arrangements, or in the case of pipelines, throughput agreements, where the shipper will pay a set price for a minimum quantity even if they do not use the service. In summary, the source of capital for the project is the liability of the party making the commitment to pay to ship the gas.

Per GAAP standards, the commitment bestows much of the rights and obligations of ownership. Accordingly, the commitment is capitalized as a long-term liability, valued at the present value of future cash flows (the tariff), and discounted at the cost of debt. If the state takes an ownership position in the pipeline, the result is a reduction in the amount of liabilities that must be carried by each of the other participants making firm transportation commitments.

If the members of the sponsor group build and own the natural gas pipeline, and the state takes its taxes and royalties in value (possible under the fiscal structure in 2005), the state pays for its capacity indirectly over time through the tariff deduction on the taxes and royalties. In a simplified explanation, the sponsor group members in this case receive 80 percent of the revenues from the gas but pay 100 percent of the capital cost and incur 100 percent of the capital risk to get the gas to market. As noted above, they recoup their investment cost over time. If the state participates with a 20 percent ownership of the pipeline, the sponsor group members receive 80 percent of the gas revenues and pay 80 percent of the capital cost and incur only 80 percent of the capital risk.

The sponsor group members evaluate the viability of the project by looking at the project's cash flows and their global portfolio of investments. One important measure is the internal rate of return (IRR).[53] Costs that are incurred early in the project life (for example, construction of the pipeline) suppress the IRR because of the time value of money. When the sponsor group members evaluate investing in the pipeline without state participation they

[53] IRR is an indicator of the net benefits that a project would provide over time, and is often used to evaluate multiple projects with higher IRRs being preferred. More formally, IRR is the rate by which future anticipated net cash flows must be discounted so that their value will be equal to the initial cost of the investment.

calculate the IRR with the early expenditure of all the initial capital costs and with revenues not starting for several years after major construction begins.

But, if the state owns a share of the pipeline and takes possession and markets the gas, the state, as the shipper, makes a firm transportation commitment to the carrier. This results in lower initial capital requirements and lower firm transportation commitments for the members of the sponsor group. With this situation, there is a reduction in initial cash outflows, and the rate of return increases significantly. (See Section 5.1.)

Another perspective on this issue is that under the 2005 fiscal system the sponsor group would provide the initial capital for the state's capacity, and, as noted above, recover their investment over time through the royalty and severance tax deduction. This would be similar to a loan to the state, the interest rate being the weighted average cost of capital embedded in the tariff. The sponsor group's opportunity cost of capital for the state's capacity is the return they make on their upstream investments, which is higher than the expected return on the pipeline investment that FERC will approve. As a result, the sponsor group's rate of return increases when the state shares in the firm transportation commitments.

4.6 Alaskans Deserve Pipeline Jobs

New jobs would be created during the pipeline's construction; it is expected that the number of workers that will be required for this construction project would be greater than what the Alaska workforce can handle. As noted in the Anchorage chamber of commerce report, a successful Alaska hire should mean that qualified Alaskans who want a job on the pipeline project can get a job on the pipeline, rather than defining success to mean that all or even a majority of the pipeline jobs go to Alaskans (Anchorage Chamber of Commerce, 2006b, Volume 2).

This section contains an overview of actions required and resources provided by the contract and federal and state acts to ensure Alaskans are considered first for pipeline jobs. The sixth of the governor's gas pipeline principles states that:

> ***Alaskans deserve Alaska gas pipeline jobs***. New direct and indirect jobs will be created in Alaska during and after the pipeline construction. The goal is to ensure that Alaskans are considered first for pipeline jobs, particularly for so-called legacy jobs that will be available even after the construction period. Training programs are being implemented to ensure Alaskans are ready and well-equipped for these jobs.

This principle reflects the concern of Alaska's citizens that the majority of jobs from the construction of the gas pipeline will go to non-Alaskans as was the case during the construction of the TAPS. Estimates from that project indicate that at the peak of TAPS pipeline construction (December of 1975) Alaska residents were 41.4 percent of pipeline workers. However, this estimate may have overestimated the involvement of Alaska's resident labor force as Alaska residency could be proven in 1974 with an Alaska driver's license, a document easily obtained in one or two days from the division of motor vehicles (Information Insights, 2004).

Construction of the proposed pipeline and a gas treatment facility would increase employment in Alaska by an estimated 9,300 direct, indirect, and induced jobs during peak construction periods (Information Insights, 2006).[54]. Many of these jobs will be seasonal and temporary in nature. A smaller but significant number of permanent employees would be needed to operate the mainline and other project components. The operation of the pipeline and gas treatment facility following construction is anticipated to directly employ about 100 workers. Indirect and induced jobs would also be created in various sectors of the economy during operations as a result of spending of the project entities, state and local governments, and households.

Current conditions are substantially different from those experienced during TAPS pipeline construction and Alaska's labor force and state government are better suited and prepared to support a project similar to TAPS. For example:

- The original projection of peak workforce numbers during the construction phase of TAPS was a maximum of 16,000 workers statewide. However, the actual number of workers was an estimated 21,600 workers, 35 percent more than expected. The labor hour increase resulted primarily from unexpected site conditions and construction difficulties. At the time, neither local nor non-local construction employees had extensive experience working in arctic and sub-arctic conditions (GAO, 1978). With more than 30 years working in these conditions, Alaska's population now includes many residents who will be able to qualify for jobs during gas pipeline construction, including some that require specialized craft training. Nonresidents will necessarily fill some jobs, and they will come largely from a pool of highly trained, gas pipeline specialty workers.

- State government provided very little in the way of workforce training to assist people in obtaining pipeline jobs until fiscal year 1974-1975 when $1.6 million was allocated, $1.1 million from the state and $0.4 million from Alyeska Pipeline Service Company. Training did not begin until well into the second construction season and there was no recorded follow up with trainees, so it is impossible to say whether or not those trained went on to get pipeline jobs. Alaska's state government is already directing funds towards a coordinated effort designed to train more workers with the skills required to construct the pipeline. The ANGPA, the SGDA, and the contract require that Alaska residents be informed of and recruited to work on the construction and operation of the proposed gas line[55]. The ANGPA provides for grants of up to $20 million to recruit and train workers in the skills required to construct and operate an Alaska gas pipeline system. To support an Alaska gas pipeline training program; up to $3 million of the grant may be used for the design and construction of a training facility to be located in Fairbanks.[56] These newly trained workers supplement a substantial, experienced in-state work force.

- Alaska's education infrastructure, from post-secondary vocational training to graduate level university education, is more robust now than 30 years ago. Alaska Department of Labor and Workforce Development Data show that Alaskan's are

[54] Peak construction would occur in January, February and March of 2010-2012.

[55] Section 113(a) Alaska Natural Gas Pipeline Act, Section Sec. 43.82.230 Alaska Stranded Gas Development Act, and Article 6.3 of the Contract.

[56] Section 113(b) Alaska Natural Gas Pipeline Act

completing local training programs at every educational level in the core pipeline construction and operation occupations (see Table 17).

Table 17. Completion of Core Construction & Operation Occupation Training Programs, by Occupation, 2004

Educational Level	Occupation Title	2004 Completions
Bachelor's degree and above	Civil Engineers	37
	Construction Managers	198
	Occupational Health and Safety Specialists and Technicians	0
Associate's/significant postsecondary training	Bus and Truck Mechanics and Diesel Engine Specialists	19
	Mobile Heavy Equipment Mechanics, Except Engines	14
Long- or medium-term on-the-job training	Construction Laborers	47
	Excavating and Loading Machine and Dragline Operators	6
	Industrial Machinery Mechanics	20
	Inspectors, Testers, Sorters, Samplers, and Weighers	0
	Maintenance and Repair Workers, General	32
	Operating Engineers and Other Construction Equipment Operators	8
	Plumbers, Pipe fitters, and Steamfitters	34
	Surveying and Mapping Technicians	65
	Truck Drivers, Heavy and Tractor-Trailer	31
	Welders, Cutters, Solderers, and Brazers	34
Short-term on-the-job training	Helpers—Extraction Workers	0
	Helpers—Production Workers	20
	Laborers and Freight, Stock, and Material Movers, Hand	7
	Maintenance Workers, Machinery	20
	Truck Drivers, Light or Delivery Services	31
Work experience in a related occupation	First-Line Supervisors/Managing Construction Trades & Extraction Workers	140
2004 Completion Total		**1043**

Source: Alaska Department of Labor and Workforce Development, 2006.

4.6.1 Training and Development Programs

The contract requires the mainline entity spend a combined total of $5 million in funding workforce training programs and activities in Alaska. The state and the mainline entity will have access to a number of existing training opportunities that may expand the skilled workforce in Alaska. Table 18 outlines current training program for selected craft trades necessary for pipeline construction and operation occupations. Additionally, the ANGPA provides grants of up to $20 million for an Alaska pipeline training program to recruit and train Alaskans, including the design and construction of training facilities located in Fairbanks to support this training. The contract requires the mainline entity to work with the state, including the department of labor to develop these or other publicly funded programs that could increase employment opportunities for Alaska residents.

Table 18. Alaska Workforce Training Programs for Selected Craft Trades

Trade	Programs in Alaska
Welders	TVC: A.W.S. welding certification
	AVTEC: Pipe Welding, 4 completers FY 2005, 2 completers FY2006*
	AVTEC: welding technology, 19 completers FY 2005, 12 completers FY2006*
	Anchorage, UAA, Welding Technology, 3 completers FY 2004
	Kenai: UAA, Welding, 2 completers FY 2004
	Ketchikan: UAS, welding, no completers FY 2004
	Sitka: UAS, welding, no completers FY 2004
	Union boilermakers in Washington
	Testing institute of Alaska: gas welding, 4; welding/pipe, 33; welding, 14
Teamsters	Seward: AVTEC, advanced drivability, 64 completers in 2002
	Anchorage: Center for Employment Education, Construction Driver Tech, 3 completers 2002
	Anchorage: Center for Employment Education, Driver Training, 62 completers 2002
	Barrow: Ilisagvik, Heavy Truck Operations, 7 exiters FY 2004
	Anchorage: Teamsters Training Center, completed 7 in last 5 years
Laborers	JATC Laborers, 52 completers in 2002
	Seward: AVTEC, Facility Maintenance/Construction, 6 completers FY 2005
	Seward: AVTEC, Facility Maintenance/Mechanical, 11 completers FY 2005
	Seward: AVTEC, Industrial Electrical, 21 completers FY 2005
Operating Engineers:	Seward: AVTEC, Diesel/Heavy Tech, 17 completers FY 2005, 11 completers FY2006*
	Anchorage: JATC Operators, 235 completers in 2002
	AVTEC, Intro to Heavy Equip Operation, 46 completers in FY 2004
	Barrow: Ilisagvik, Heavy Equip Operators, 20 completers 2002
	Barrow: Ilisagvik, Heavy Truck and Equip Opera, 2 exiters FY 2004
Inspectors	AVTEC: Inspection/ maintenance, 237 completers 2002
Surveyors	Anchorage, UAA, survey and mapping, 1 completer FY 2004

Source: Information Insights, Inc. 2004. Information updated by the Alaska Department of Labor and Workforce Development, 2006.

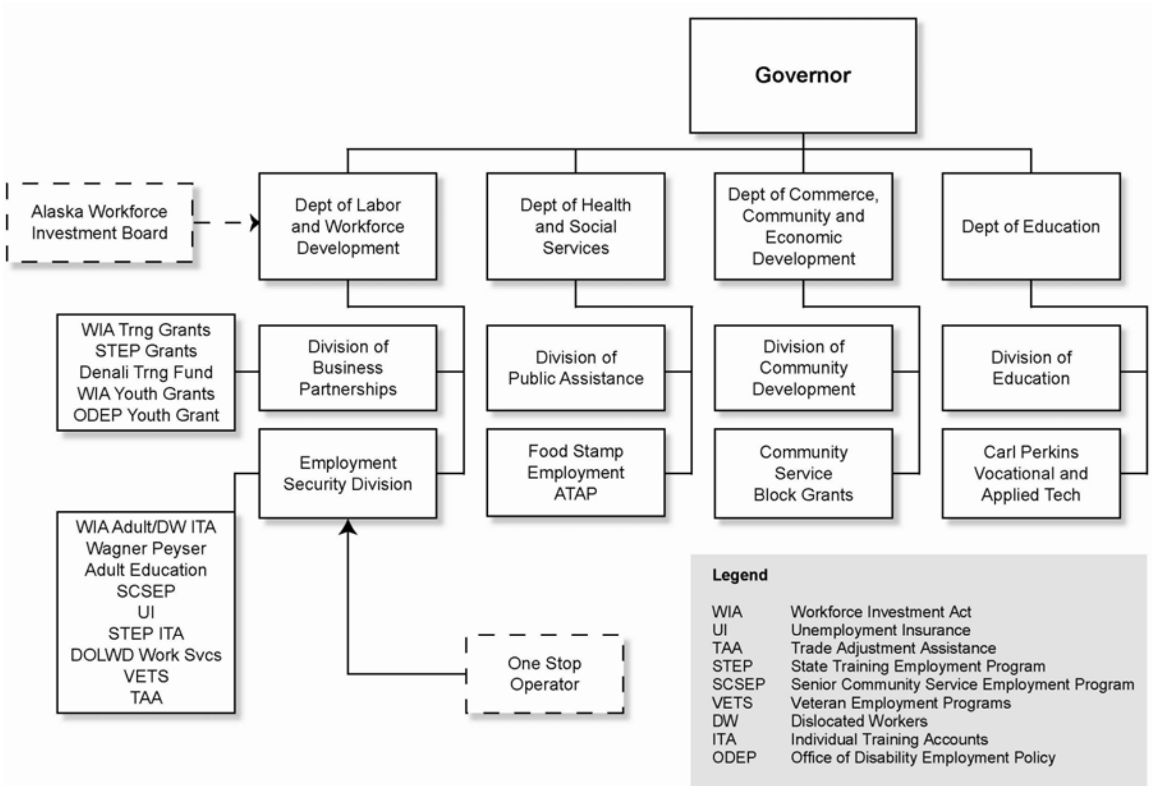
Note: FY 2006 numbers only include July 2005 to January 2006.

4.6.2 Alaska Workforce Development Structure

Complementary to, and supporting, the training programs above, Alaska's public workforce development program provides an employment and training system that is locally focused and locally driven through a "one-stop" job center service delivery system that integrates a broad array of employment and training programs (see Figure 22). The ADOL&WD's division of business partnerships (DBP) is the recipient of Workforce Investment Act (WIA) funds and manages the grants on behalf of the public workforce system to other state agencies and with vendors contracted for training programs. The Alaska Workforce Investment Board (AWIB) provides oversight and planning for the one-stop system of employment services and articulates the coordination amongst state agencies. The Alaska job center network (AJCN) provides employment, counseling, and referrals to training services for job seekers and employers at full-service offices and satellite centers around Alaska and through its website. DBP passes federal funds through to the AWIB, the ADOL&WD's

Division of Employment Security (ESD), the operator of the one-stop job service centers, and the Employment Security Division (ESD). DBP also maintains a management information system for worker case management and training program performance. This data is provided to the board for review and evaluation (ADOL&WD, 2005b).

Figure 22. Alaska's Public Workforce Investment Agencies and Programs



Source: ADOL&WD, 2005a.

4.6.3 Gas Pipeline Workforce Development Strategic Plan

A key component to ensuring "that Alaskans are considered first for pipeline jobs, especially legacy jobs that will continue after construction is complete" is part of the strategic plan the ADOLWD developed to address the issue directly (ADOL&WD, 2005b). The plan identifies four objectives and supporting strategies to achieve this goal. In summary, these objectives and strategies seek to ensure that Alaskans are qualified to seek pipeline jobs by increasing the accessibility of existing programs while promoting public/private partnerships that would strengthen existing programs and create new ones.

Objectives and strategies of the plan are:

(1) Target workforce development investments toward public/private partnerships for worker skills development in energy related occupations.

Supporting strategies:

- Invest workforce development resources in training for high growth jobs in pipeline construction, maritime, transportation and associated occupations, including technical math and skill instructor training.
- Invest in a public information campaign that increases public awareness of job opportunities in Alaska's labor market, including youth awareness of career opportunities.
- Invest in training equipment and instruction technology to expand training capacity.
- Invest in web based e-commerce information system for internal and external customer information and a research platform for project evaluation, improvement, and sustainability.
- Form partnerships with energy industry companies to enhance employment of Alaskans.

(2) Integrate vocational and technical education with skill training providing paths to energy related jobs.

Supporting strategies:

- Provide training funds to workers to attend high growth industry training.
- Align prevocational training with industry apprenticeship courses to streamline access to apprenticeship and career training.
- Expand industry career activities for high school age youth.
- Use established competency-based education skills assessment instruments to provider workers credit for skills and knowledge already obtained.
- Support further development of energy industry education compacts.

(3) Increase apprenticeship training and worker skills for energy related jobs.

Supporting strategies:

- Establish a single point of contact at job centers for apprenticeship connection.
- Promote apprenticeship and on-the-job training with employers and provide services and incentives for employers to hire apprentices.
- Increase internship opportunities.
- Establish an apprenticeship advisory committee.
- Encourage industry lead apprenticeship utilization standards.

(4) Make the department's one-stop career system, including a new web-based labor exchange system, the source for employer/worker connections.

Supporting strategies:

- Streamline intake and improve core and intensive services at Alaska job centers.
- Streamline individual training account resources for qualified training providers.
- Create an industry-centered model to reach out to and serve targeted populations.
- Continually evaluate the effectiveness of services and programs.
- Market and deliver industry-centered job center services to high growth employers.

4.7 Other Major Issues

This section describes and discusses other major issues related to the contract and the project that are deemed to be important considerations in the commissioner's findings and determination.

4.7.1 Issues Related to Royalty Gas and Tax Gas

The state will take possession of its royalty share of natural gas and the gas production payment. In taking delivery, the state assumes ownership, title, financial responsibility, and risk of loss for its gas production payment and royalty gas. The production payment is a fixed percentage (7.25 percent) of the production tax value received by each producer for its tax bearing gas from a property (See Section 3 for details on these terms).

By taking possession of the gas, the state gives up any right to argue that the state under certain leases or per production tax regulations does not have to pay certain costs. For example, the state will pay the sponsor group for impurities disposal and for field gathering, cleaning, and dehydration. Also, the state will incur costs for marketing its gas, some of which the state has argued it does not have to pay. These costs would include:

- payments to gas hub operators for administrative services (e.g., title transfer tracking) necessary to account for the sale of gas within a hub;
- payments to parties that arrange marketing or transportation;
- payments to parties that provide scheduling services; and
- salaries and related costs, rent, office equipment costs, legal fees, and other costs to manage the movement and sale of the gas.

The state also gives up the right to switch between taking the royalty gas and receiving cash for it. Receiving royalty gas under the terms of the contract is a change from the current fiscal terms, as described in state oil and gas leases, in which the state has the option of deciding every three or six months (depending on the lease) whether to receive royalty payments as the value of the gas, or taking possession and selling the royalty gas. This system allows the state flexibility to switch from cash payments to possession of the royalty gas to maximize resource value when opportunities arise to sell gas at premium

This switching option has value. In 2002, in anticipation of an open season on a gas pipeline, the ADNR solicited and received offers from Anadarko and AEC Oil and Gas for a call option on the state's royalty gas. This option would buttress their exploration efforts to fill any firm transportation commitments they made in the open season. Anadarko offered to pay \$2 million up-front, and \$2 million every five years, in return for an option to purchase up to 70 percent of the state's royalty gas (then estimated to be 500 mmcf/day). Anadarko also agreed to commit to exploration work, to pay a reservation fee of two cents on any gas on which it exercised the option, and to pay a premium over the value received on other royalty gas (Anadarko, 2002).

While the state wanted to encourage exploration, the sponsor group argued that providing this option would adversely impact the economics of the gas line. The sponsor group would be faced with a difficult choice. On the one hand, if the sponsor group expected the explorer to be successful, the members of the sponsor group could bid for enough shipping capacity to transport the producer's equity gas and the state's royalty gas. In that event, if the explorer were unsuccessful, the state would take possession of its gas, and sell it to the explorer. The sponsor group would then be left with excess capacity. On the other hand, if the sponsor group expected the explorer to fail, they would purchase enough capacity to transport their equity gas only, expecting that the royalty gas would be used to fill the explorer's shipping commitment. In that event, if the explorer were successful, the state would switch from taking possession of its gas to requesting the value for the gas, and the explorer would fulfill its shipping commitment with the gas it had discovered. By the state taking the value of the gas, however, the sponsor group would be required to use their capacity to transport state royalty gas, capacity that the producers had intended for their equity gas. As a result, for a fixed capacity line, the sponsor group's proceeds would be lower by the total value of the royalty gas (though its cost would also be lower as it would treat the tariff as a deductible item before paying the value of the royalty gas).

Although issuing a final finding, the ADNR never accepted the offer to sell the gas to Anadarko and AEC, and the state agrees under this contract to make a one-time election to take delivery of all royalty gas. In its modeling of the 2005 fiscal structure, the state models took into account this switching option value. A benefit of taking the royalty share as gas under the proposed fiscal contract is that it eliminates the uncertainty that makes it more difficult to get financing if the gas volumes the sponsor group commit to the project can be changed by the state every three months.

If the state took its royalty in cash, it could have argued that under the lease it has the right to take the higher-of various measures of value. Lukens estimates that the value of this "higher of" option is approximately two percent of the expected average gas price, with AECO having a slightly higher option value of 1.9 to 2.1 percent and Chicago having an option value of about 1.8 to 1.9 percent. (Lukens Energy Group, 2005) Foregoing this option value will result in the state receiving about two percent less for its royalty gas sales under the fiscal contract than could be achieved under the 2005 fiscal system. This difference is incorporated into the analytical models that are used to present the effects of the proposed fiscal contract. The exercise of a higher-of, as well as the right to receive cash for the royalty share under certain leases free of field and marketing cost deductions would be disputed, and maintaining those disputed lease rights would be a source of uncertainty for the project. Section 4.1 presents the estimated state revenues net of the marketing costs and other costs that the state may incur. In addition to these estimated marketing costs, the state may also incur unexpected costs (risks) that are discussed in Section 6.

4.7.2 Predictable and Durable Terms for Alaska's Share

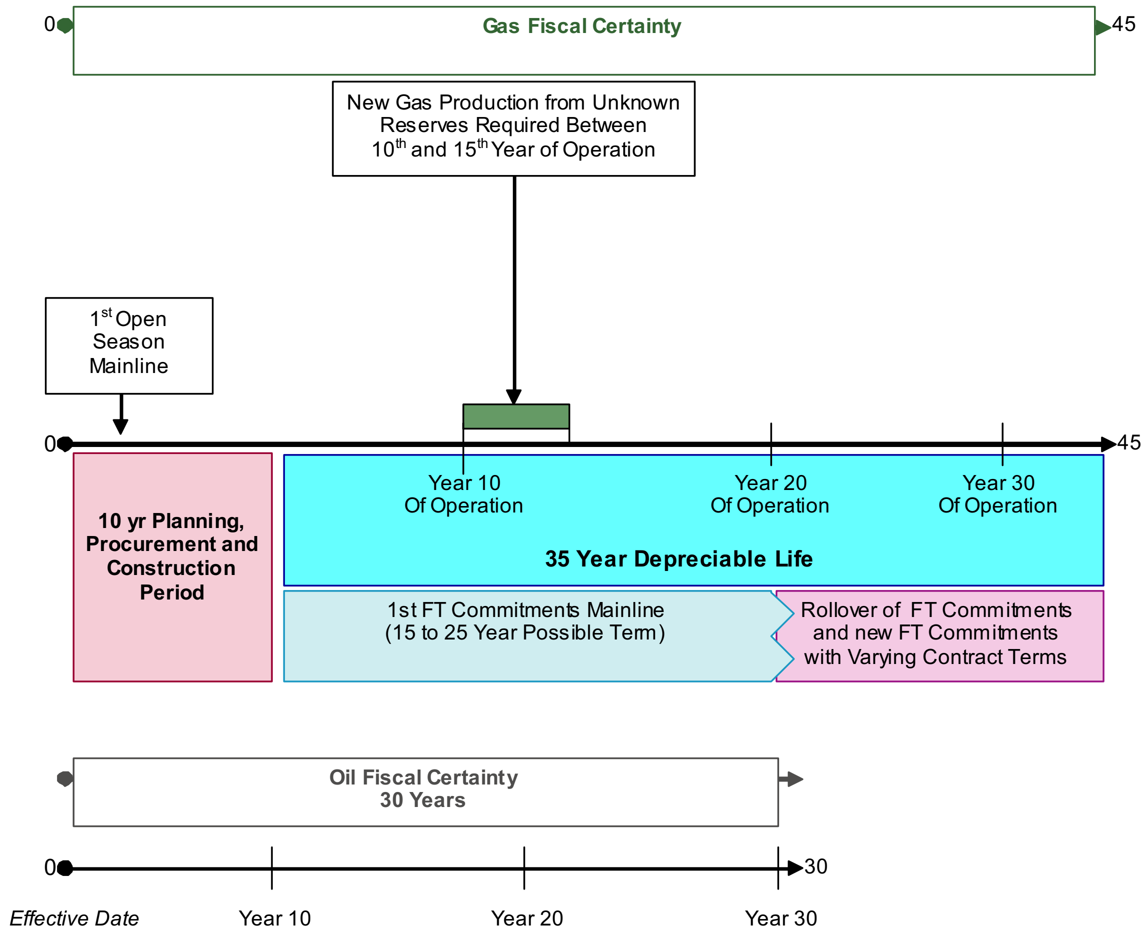
The 45-year period (assuming a 10-year ramp up and 35 years of operations) of fiscal certainty is intended to provide a long term stable investment climate to develop known resources to stimulate exploration and development of resources yet to be identified, and to lock in the fiscal requirements that will frame the development of the project.

Legislation will be introduced that extends these same assurances of fiscal stability that the sponsor group receives to any party with ANS gas that makes a long term firm transportation commitment on the pipeline. This 45-year period also is intended to spur exploration and discovery of gas fields that require a long term development horizon in order to provide the project with the necessary gas volumes over the life of the infrastructure and, hopefully, to justify expansions.

As described above, this will be the largest and most expensive private construction project in modern history with current conservative cost estimates exceeding $21 billion. It is important to understand the chronology of events that will be required to bring this project to fruition and to successfully operate over 35 years. The planning, permitting, certification and construction process in the United States and Canada will likely require an 8 to 10-year period to complete. An open season will be held by the mainline entity and GTP entity two or three years after the effective date and at such time, the primary shippers (the state, BP, CP, EM, and possibly others) will make firm transportation commitments to ship their proportional volumes of gas on the new project. These commitments will be made to the entity that will operate the mainline, which will in turn use these firm transportation contracts to help establish the financial viability of the project with regulators and prospective lenders. These initial commitments will likely be for a period of between 15 and 25 years. At this time it is estimated that the state and the producers will not be in a position to make a decision to proceed with construction of the project until four or five years after the effective date of the contract. Current projections indicate that additional gas will be needed to keep the pipeline running at capacity depending upon final design and offtake requirements somewhere between 15 and 20 years after commencement of operations. More gas needs to be found.

If sufficient gas is found, the capacity of the pipeline may be expanded to deal with any increased volumes and separate open seasons could be held for the expanded capacity. Subsequently, additional mainline open seasons could be held prior to the expiration of the initial commitment period depending on contract terms established in the first open season. The initial contracting parties may have rights of first refusal upon additional capacity depending on the terms set in the first open season. Depending on the pace and extent of new gas discoveries, there also could be additional open seasons anytime during the life of the pipeline as well as expansion open seasons if new pipeline capacity is needed. The terms of these commitments will vary depending upon the circumstances at that time. Figure 23 shows a possible timeline for these future events and displays the basis for the 45-year contract term.

Figure 23. Possible Project Timeline and Fiscal Certainty



Notes: FT is firm transportation.

The state believes the 45-year period of fiscal certainty for gas is required. First, since the project will take up to 10 years to complete, 45 years is a reasonable estimate of the period it will take equity owners to both build the gas pipeline and to recover their investment. The producers and the state anticipate that FERC will establish a depreciable life of the pipeline in the range of 30 to 40 years based on both known gas resources and potential gas resources that will likely be discovered in the future. This establishes the period over which the capital costs of the project can be depreciated, that is, recovered in rates by the project sponsors and the state. A longer period of depreciation is generally beneficial to shippers since it should function to lower the tariff charge, at least in the early years of the project. Thus, it seems reasonable for the state to provide fiscal certainty during the construction period as well as during the additional 35-year period that will likely be required to recoup all or most of the equity owners' investment.

The length of the fiscal certainty period is also important to prospective lenders to the project. The term of debt floated to finance the project could range from fifteen to twenty five years although this cannot be known with certainty until the project is better developed and the requirements of the financial markets at the time established. Lenders would customarily expect a cushion of fiscal certainty beyond the exact term of the debt. The cushion provides a margin to ensure repayment of the debt if there is a disruption of gas pipeline operations or production flow during the term of the debt that resulted in an extension or rescheduling of the debt. A thirty-five year term provides the necessary cushion.

In addition, the success of the project is dependent upon the discovery and development of additional gas. The 35 tcf of known gas resources on the ANS reported by the ADNR will likely be produced in the first two decades of commercial operation. Thus, the contract provides producers certainty with respect to the fiscal regime for gas over the 35-year period authorized by the SGDA in order to provide further exploration and development incentives to fill the pipeline for its estimated useful life.

The duration of this contract is similar to those in place elsewhere in the world. A review by van Meurs identified other contracts and the duration after the effective date of the contract. The average duration for the 46 production sharing contracts was 34 years. Not included in this average are voluntary extensions where the parties can agree to extend the contract beyond the initial contract period. Inclusion of the term of the options for extension would increase the average duration of the production sharing contracts.

Table 19. Duration of Production Sharing Contracts

Duration in Years	Number of Contracts
20 – 24	2
25 – 29	10
30 – 34	15
35 – 39	7
40 – 44	7
45 – 49	5

Source: van Meurs, 2005b.

4.7.2.1 Fiscal Certainty on Oil

There are five primary reasons for providing fiscal certainty on oil taxes for a 30-year period. First, the state felt that it had to address the producers' concern that the benefits of fiscal stability on gas production, property, and income could be eroded or offset by changes to the taxation of oil production, property and income during the life of the project[57].

Second, the producers argued and the state ultimately agreed that it was in the interests of the project and all of the parties to the SGDA contract to have a similar alignment of economic interests with respect to the relative benefits of producing oil versus gas. Oil and gas are commonly produced in association with each other. On the North Slope gas has traditionally been used to maximize oil production. Fiscal certainty on oil combined with the enactment of the net profits production tax could help minimize disputes between the state and the

[57] Looking back at the TAPS experience after the pipe for TAPS had been ordered and started arriving in Alaska, the State changed the tax laws applicable to Prudhoe Bay and TAPS 14 times in the next decade, and the great majority of those changes were tax increases for Prudhoe Bay or TAPS, or both (Anchorage Chamber of Commerce, 2006a).

producers over production priorities during the first three decades of their partnership in this commercial undertaking.

Third, the new PPT is a tax on oil and gas production with expenses incurred in gas exploration and development deductible or creditable against taxes due from oil production. The state believes that it is in its own best interests to immediately provide tax benefits associated with gas exploration and development in order to assure that a sufficient gas supply is in place for the 35-year period of commercial operations under the contract. As noted earlier, the success of the project is dependent in part on the near term discovery of new gas fields. Such fields generally take from six to eight years to bring into production, and this new gas could be needed as soon as 15 years after project sanction, in order to maintain the operation of the mainline at optimal design capacity.

Making sure that the pipeline is full for the contract term will increase the probability that investments will be made in the project at the project sanction date. However, the main beneficiaries of increased production and transportation of gas are the state and the affected municipalities, which will receive significantly more revenues proportionately with the increased volumes. Furthermore, the value of the state's gas increases because the average transport tariffs are lower after the debt financing is paid off. It is in the state's interest to take all steps required to increase the volumes to be produced and transported through the mainline.

The 30-year period is designed to provide a stable regime on oil up until the approximate time when decisions related to the use of potentially available capacity on the mainline have to be made in order to keep the mainline full for the contract term. This point in time is the critical period when new gas supplies must be identified so they can be developed in time for the Alaska natural gas pipeline project to succeed. New exploration efforts will typically be for oil as well as gas. Exploration decisions are typically justified on the basis of the possibility of making oil as well as gas discoveries. Therefore, in order to stimulate new exploration, fiscal stability for oil as well as gas is an important factor in the decision. A detailed analysis of international exploration and production contracts indicates that a 30 year fiscal certainty period is a relatively short period for the high cost and high risk areas such as the ANS. Therefore this is the minimum period required to stimulate significant new exploration efforts.

Such incentives will also enhance the possibility that an expansion of capacity would be required in the first decade of commercial production. The 30-year period then is designed to provide a stable regime on oil up until the approximate time of the second "open season" for acquisition of capacity on the main pipeline. This is the critical period when new gas supplies must be identified and developed for the remaining life of the Alaska natural gas pipeline.

Fourth, fiscal certainty on oil will also stimulate exploration and development of smaller oil fields, or the application of new technologies to the production of heavier crude oil remaining in existing fields. The ADOR forecasts that production from the North Slope will fall to approximately 770,000 barrels a day by 2016.[58] The deductions for capital expenditures and tax credits available to BP, CP, and EM, as well as to other taxpayers, will increase the

[58] ADOR, 2006. Spring 2006 Revenue Sources Book. At http://www.tax.state.ak.us/sourcesbook/2006/spr2006/execsum.pdf. (Accessed April 16, 2006.)

likelihood of other discoveries and of the application of new technologies that will help stem the decline of oil production and help fill the TAPS.

Finally, oil fiscal certainty will also minimize the potential grounds for tax disputes between the state and the members of the sponsor group. For example, the process of distinguishing between oil production facilities and gas production facilities for property tax purposes would inevitably lead to some differences of opinion. Likewise, separating income earned from oil versus gas operations for corporate income tax purposes would require elaborate provisions to segregate income and expenses for gas operations from those associated with oil operations under separate tax regimes and may lead to additional differences. In the past, tax exemptions that were limited to revenues from a particular project have engendered a great deal of litigation between the state and the taxpayer over the boundaries of such an exemption. For example, the Alaska Supreme Court twice resolved disputes between the state and Union Oil, which had been provided a tax exemption certificate under the Alaska Industrial Incentive Act of 1957 to subsidize the construction of a fertilizer plant on the Kenai Peninsula. Although such provisions would still be required for the final 15 years of the gas fiscal stability term, at least this requirement to segregate oil and gas income and expenses would not be a source of friction during the critical early years of the project.

4.7.2.2 Petroleum Profits Tax

The State of Alaska receives revenue from oil development through property tax, corporate income tax, royalties, and production tax. In fiscal year 2005, the state received $3.6 billion in oil revenues; approximately 54 percent was attributable to royalties, 7 percent property tax, 15 percent corporate income tax, and 24 percent attributable to the production tax.

Governor Murkowski has recently introduced legislation to change the production tax. Currently the production tax is based on the gross value of oil and gas production. The nominal tax rate is 12.25 percent for the first five years of production and 15 percent thereafter. There is a minimum tax of 80 cents per taxable barrel. The nominal rate is then adjusted downward based upon an Economic Limit Factor (ELF), which is the variable used in oil and gas production tax. The ELF formula results in lower effective tax rates for smaller, low-production fields and higher tax rates for larger, highly productive fields. There is a unique ELF for every combination of total daily field production and average daily per well production. When the ELF was amended in 1989, crude oil prices ranged from about $14 to $17 per barrel and it was thought that wells that produced 300 barrels per day or less would not be profitable at crude oil prices in that range, if they had to pay severance taxes. It was also thought that fields producing less than 150,000 barrels per day would not be profitable at these price levels if severance tax payments were required. The ELF was established to ensure that oil production would continue even if prices were low, and high oil prices were never envisioned. As a result of the ELF, severance tax collections as a share of crude oil prices decline from 25 percent at $15 per barrel to about 8 percent at $60 per barrel (ADOR, 2006b).

For a fiscal system to be durable and stable, the public and industry must believe that system adapts to changes in circumstances over time in such a way as to keep providing:

1. a fair share of the resource's economic rents to the state,
2. producers with an adequate rate of return on their investment,
3. incentives for producers to invest more,
4. clear, consistent rules for implementation.

Viewed as to its ability to achieve these goals, the ELF production tax system was broken. To accomplish the first two goals, a tax system should vary the tax burden on a field in such a way as to tax a profitable field more, and a less profitable, marginal field less. The ELF production tax varied the tax rate based on proxies for field profitability, namely field size and well productivity. Over time these proxies as used in the ELF formula failed to adequately capture field profitability because they did not adjust with price or adjust for changes in production methods, technology, and costs.

All else equal, a field's profitability will vary with oil prices. Oil prices however are not part of the ELF formula. The ELF formula is also based on outmoded field development scenarios. The type of fields brought on-line on the North Slope has changed since the ELF was last modified. Since 1989, North Slope producers have brought on many satellite fields. These pay little or no severance tax because these fields have too little production to justify building their own dedicated facilities. Yet each is evaluated as if it had invested in its own dedicated facility. Satellite fields share separation and other facilities with other fields, and this sharing of costs allows them to take advantage of large-field economies of scale.

Even for stand-alone fields, production costs have been substantially reduced. (Attanasi, 2003) Advances in development drilling such as the drilling of horizontal and multilateral wells are allowing smaller fields to be economically developed. Coiled tube drilling at a fraction of a cost of conventional rotary well drilling (as well as other advances in drilling technology) have made in-field drilling cheaper, thereby extending field life. While ELF and the effective tax rate have rapidly gone to zero for the large Kuparuk field, that field continues to produce, and its estimated field life continues to be extended.

The ELF provides the wrong incentives. It discourages investments that increase both a field's well productivity and field size. That is, it saddles projects such as in-field drilling, EOR projects, and well workovers with high marginal tax rates. In a mature oil province like Alaska's, these are the very projects the state should be encouraging. In addition, the ELF discourages one large planned project that substantially increases well productivity: the proposed gas line project. The ELF as it currently operates would automatically increase the effective tax rate for oil with a gas line project. To avoid this automatic tax hike on oil with a gas sale, the state could ignore gas sold into the project when computing an oil ELF. Doing so, however, means that the oil ELF for Prudhoe Bay will decline to zero a few years after a gas line start-up, and over 30 years before the projected end of field life.

The ELF also led to conflicts over the definition of a field, the definition of a well, and to when fields could be aggregated because they were economically interdependent. The PPT remedies the Elf's deficiencies. The PPT directly measures production revenue and costs rather than relying on indirect proxies for profitability. The PPT appears robust and durable to changing circumstances of higher or lower prices, or changing technology. If technology leads to a decrease in development costs and a concomitant increase in profitability, the PPT tracks the change. If maintenance costs increase due to the age of the facility, and profits decline, the PPT tracks the change. For this reason, if the public or the oil companies consider the PPT as fair today, they likely will consider it as fair years from now.

The PPT also powerfully encourages investment. For every dollar of capital invested in Alaska, the investor receives 40 cents back in the form of lower taxes (or a transferable tax credit certificate). For every dollar of profits not re-invested, the investor pays 20 cents (one dollar times the PPT tax rate). Unlike ELF, the PPT doesn't distort the investment decision by favoring certain types of investment (separate field satellite developments) over other types (well-workovers in large fields). By providing an efficient and powerful incentive to invest, the PPT should lead to more oil production over a longer period.

In addition, future exploration and development will be encouraged by means of investment credits. The PPT will provide additional incentives for future exploration to mitigate the risk of investment. The proposed PPT is a tax on oil and gas production, but expenses incurred in gas exploration and development are deductible or creditable against taxes due from oil production. In order to encourage gas exploration and development the state believes it is in its own best interest to immediately provide tax benefits associated with exploration. The success of the project is dependent in part on the near term discovery of new gas fields. Such fields generally take from six to eight years to bring into production, and this new gas could be needed as soon as 15 years after project sanction, in order to maintain the operation of the mainline at optimal design capacity.

Finally, the PPT has been crafted to limit the conflicts which arise over implementation. When able, PPT administrators can rely on audited joint interest billing statements, or federal tax or FASB definitions of capital investments.

The PPT is related to the issue of fiscal certainty, as any oil tax changes would be incorporated in the gas contract and fixed for 30 years as currently proposed.

4.7.2.3 Gas Reserves Tax

On March 6, 2006 the lieutenant governor certified an initiative petition 05GAS2:

> "An Act levying a tax on certain leases having known resources of natural gas, conditionally repealing the levy of that tax, and authorizing a credit for payments of that tax against amounts due under the oil and gas production (severance) tax if requirements relating to the sale or shipment of the natural gas are met; and providing a effective date"

This initiative, commonly known as the gas reserve tax, will be voted by Alaskans on November 7, 2006. If approved by the voters, this initiative will become an Alaska statute and will impose a tax of 3 cents per mcf of gas on certain leases, including most of those on the ANS having known gas resources. The proposed statute also contains provisions for recouping a portion of gas reserve taxes paid over a period of time after the leases are producing gas.

Article 11 (Fiscal Stability) of the contract sets out a covenant in which, among other things, the state agrees to provide fiscal stability. One of the tax changes specified under this article is a provision which makes a sponsor exempt from the payment of certain new state taxes which are not expressly designated as payable under the terms of the contract. These exempt taxes include a mandatory payment that is imposed by the state under a law initiated by the people ". . . on reserves or resources in place . . ." Article 11.2(b) and Article 1 (definition of "tax").

The reserves tax raises serious concerns on two fronts. First, per the SGDA, it is the policy of the State of Alaska to promote fiscal certainty as a means to enable construction of the gas pipeline. The rationale for fiscal stability has been presented in this document. Fiscal certainty addresses more than the legislative statutory process; it also addresses the ballot initiative process as well. Without inclusion of the initiative process, fiscal stability does not exist. In addition, the imposition of the tax while the producers are engaged in good faith negotiations with the state demeans the SGDA process.

Second, the reserves tax will create a poor investment climate for the following reasons:

- Insofar as the gas is stranded, the tax pre-supposes viability of the project regardless of the economic realities. The tax would punish the sponsors for not building the project even if gas prices were very low and the project was not economically viable.
- Even though the tax would only apply initially to Prudhoe Bay and Point Thomson, any potential explorer would consider the possibility that the tax would be expanded to include other deposits. It is very likely all oil and gas exploration would cease since an explorer looking for oil could find gas. Since about 18 additional tcf of gas needs to be discovered to fill the pipeline for the contract period, any decrease in exploration activity would be harmful to the state.
- The risk of the tax would extend to other petroleum resources. Nothing would prevent the state from imposing a similar tax on the North Slope's billions of barrels of very expensive to produce heavy oil. Again, any potential developer would recognize this risk.
- The reserves tax could create a situation where the state might be motivated to cause the project to be delayed, or place unreasonable demands on its structure.
- No other jurisdiction has a mechanism like the reserves tax; the reserves tax would put our international competitiveness at risk.

Passage of the gas reserve tax would adversely impact the project economics of the sponsor group who, along with the state, intend to construct the project. Imposition of an exemption to offset the gas reserve tax is necessary if the project is to proceed toward construction. Passage of the gas reserve tax would adversely impact the project economics of the sponsor group who, along with the state, intend to construct the project. Imposition of an exemption to offset the gas reserve tax is necessary if the project is to proceed toward construction. The following is an economic discussion supporting these conclusions.

An economic analysis was carried out in order to assess the impact of a possible reserve tax on the project. The analysis was done with the PVM gas-only model which assumes an 8 year evaluation, regulatory and construction period from 2006 onwards. This would mean that the gas line would be initiated in 2014. The analysis was done in constant 2006 $ and based on a project ending in Alberta.

Assumptions about the Reserve Tax

The following assumptions were made about this tax:

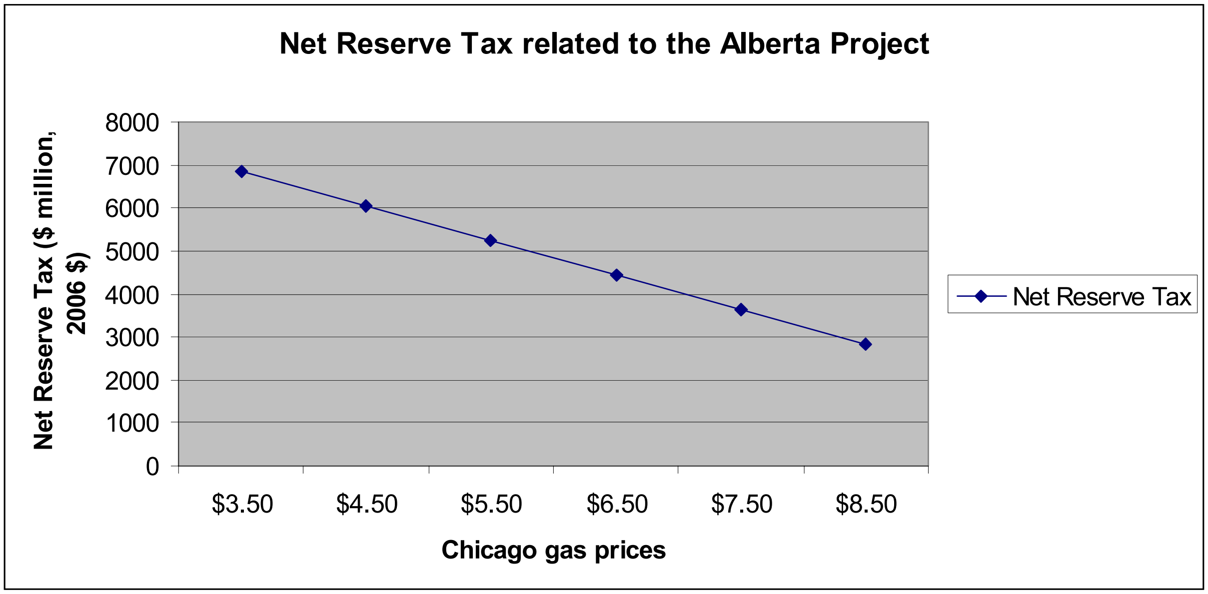
- The tax would apply for the 8 year period from 2006 through 2013 and the tax obligation would be repealed starting 2014.
- The tax would apply to 35 tcf of gas.
- The tax would be US $ 0.03 per 1000 cubic feet of gas. The tax would have to be paid each year. This means that over the 8 year period the total tax payments would be $8,400 million.
- The tax could be recovered from 50 percent of the production tax. In the model this was interpreted to mean that 50 percent of the tax gas would be assigned to the producers for the recovery of the tax based on the value of the tax gas up to the cumulative tax amount paid. The recovery would not include any taxes paid in the first two years (prior to the open season).
- The opportunity to recover the tax would terminate on December 31, 2030.

Impact on Total Alaska Revenues

The net reserve tax that would be paid is $8.4 billion less any recovery of this tax during the 2014 - 2030 period against the value of the tax gas. The amount of the recovery depends directly on the Chicago city-gate gas price, which in the case of a project ending in Alberta really means the gas price in Alberta. The higher the gas prices, the more the recovery. Nevertheless, in the price range of $ 3.50 to $ 8.50 for delivery in Chicago, there would not be a complete recovery of the $6,300 million that could be repaid to taxpayers under the terms of the initiative.

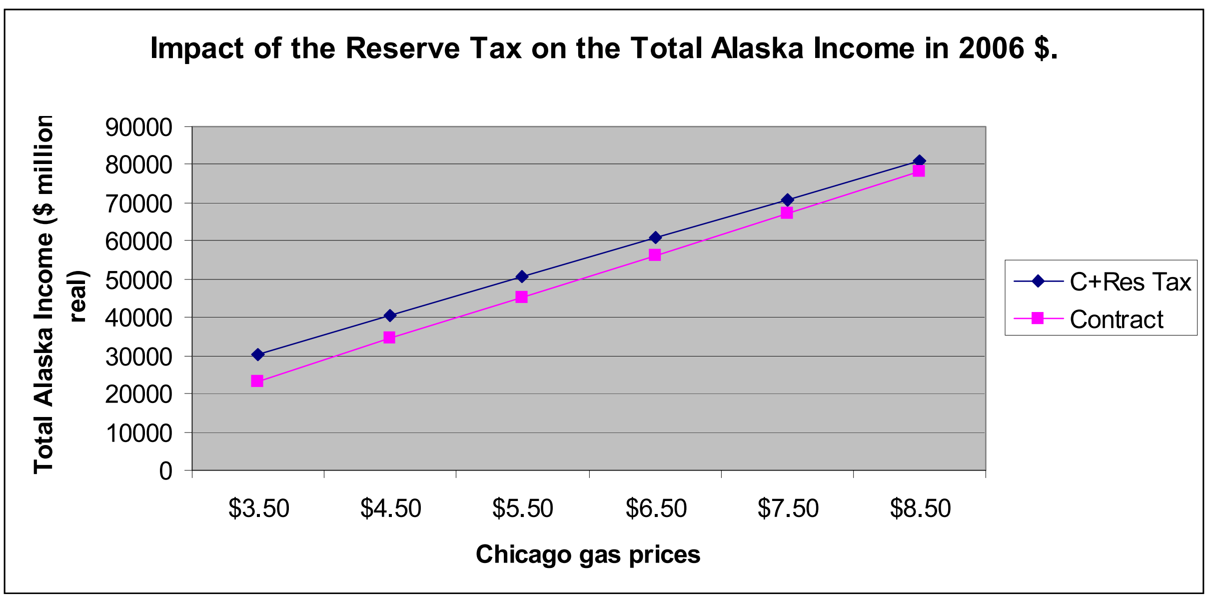
Figure 24 illustrates the amount of the net reserve tax. At 3.50 per mmBtu in Chicago the net effect of the Reserve tax would be $ 6844 million and at $ 8.50 per mmBtu it would be $2,840 million.

Figure 24. Net Reserve Tax Related to the Alberta Project



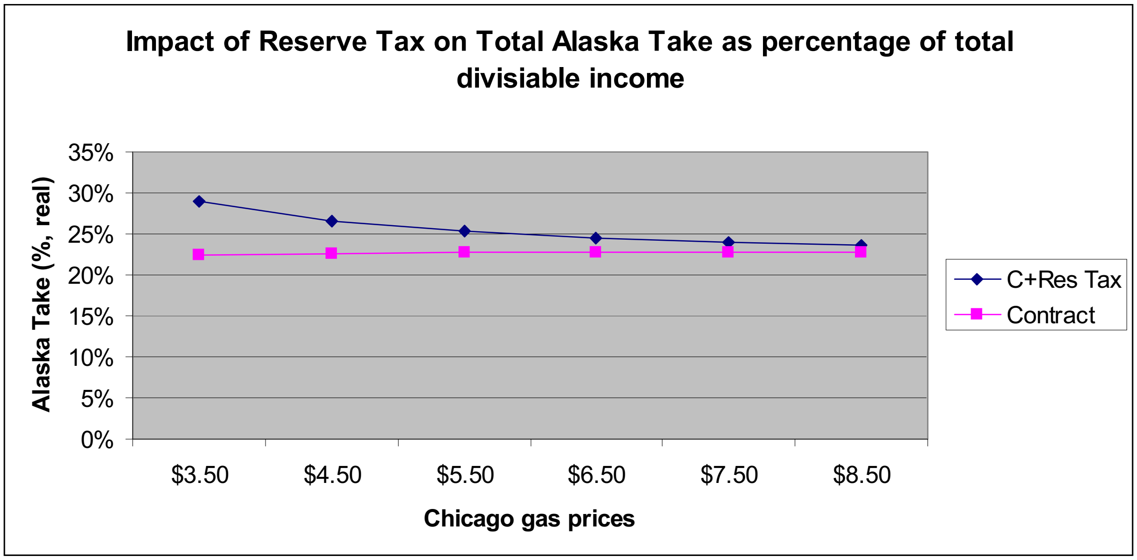
It is obvious that such high net reserve tax amounts would have a very large impact on the total Alaska income under low prices. Figure 25 shows this total impact under the proposed contract with and without the net results of the reserve tax.

Figure 25. Impact of the Reserve Tax on the Total Alaska Income in 2006 $



The much higher taxes at low prices would create a regressive tax system with respect to price. The Alaska take is displayed in Figure 26 for the price range.

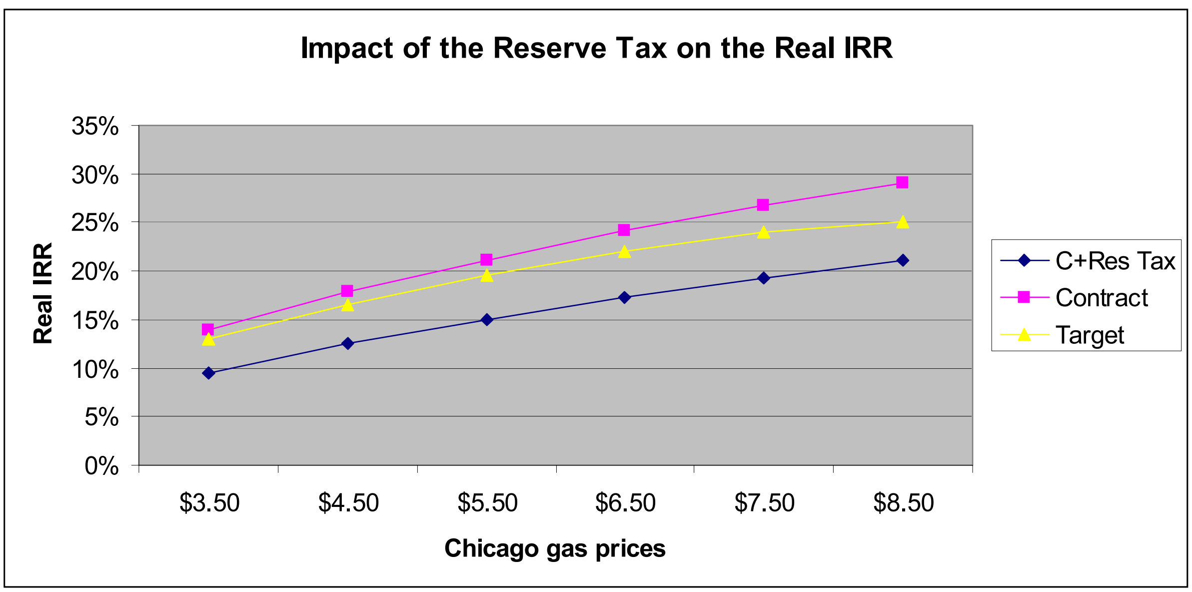
Figure 26. Impact of Reserve Tax on Total Alaska Take as Percentage of Total Divisible Income



Impact on Investors

Figure 27 illustrates the impact that the reserve tax would have on the project IRR.

Figure 27. Impact of the Reserve Tax on the Real IRR



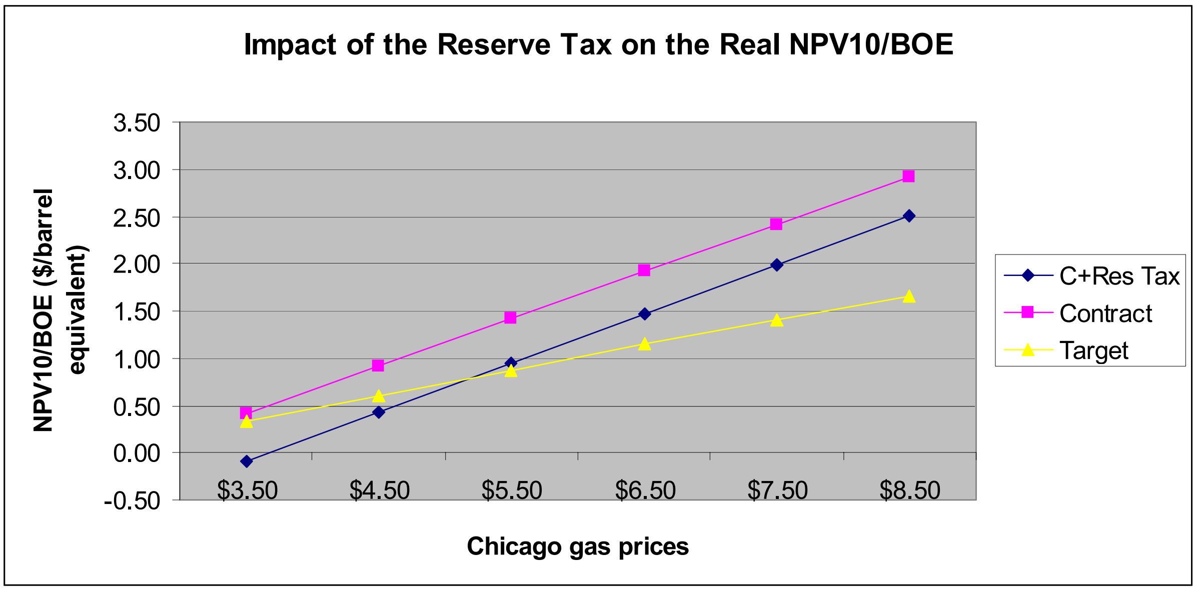
As the above chart clearly shows, the reserve tax would have an adverse impact on the real project IRR. This is because the tax has to be paid early in the cash flow in the period prior to the start of the gas transport operations. The subsequent recovery of the amounts paid takes place over a long time and the recovery is not adequate for the price range considered in this report.

The reserve tax would create a project with a highly unattractive IRR which is about five percentage points below the target levels discussed in Section 5.1 of this report. However, other profitability indicators would also be negatively affected.

Figure 28 shows the impact of the reserve tax on the real NPV10/BOE.

The reserve tax would create conditions where the NPV10/BOE would end up well below the target values and even with negative values at the stress price.

Figure 28. Impact of the Reserve Tax on the Real NPV10/BOE



It can be concluded that the reserve tax makes the Alaska gas project uneconomic and uncompetitive measured by a variety of important economic profitability indicators.

Investors need protection from a reserve tax in order for the project to be viable. It is therefore absolutely necessary that the fiscal stability provisions include such protection.

4.7.3 Work Commitments

As noted in Section 3.5, Article 5 requires the participants to advance the project "as diligently as is prudent under the circumstances" until project sanction. In the public dialogue, citizens of Alaska will ask, as some public comments have asked, why the project sponsors cannot give an unequivocal commitment to building the project today. The answer is that there is too much uncertainty about the costs and benefits of a hugely expensive project that will take years to design, engineer, and secure permits for, and additional years after that to construct. At the present level of engineering the costs are only rough estimates at best. Nor can anyone know today what the costs of compliance with the governments' environmental requirements. Nor one can know today what the cost of steel will be when it is procured perhaps five or seven years from now. Likewise, no one can know today how other projects in North America and, indeed, around the world will affect the availability of materials and skilled manpower needed for the pipeline. While there is a fair degree of certainty concerning the amount of time required for the regulatory process in the United States due to the requirements of the ANGPA, there is far less certainty over how long the permitting and right of way process in Canada will take, and thus the costs involved. As another example, the cost of the construction funds that will be borrowed five, six or seven years from now could fluctuate over a wide range.

On the revenue side, the market price of gas can also be projected for years and indeed decades into the future. However, as with cost, accuracy is an issue, the longer the time frame of the forecast, the higher the degree of uncertainty. The costs and benefits of the project are only estimates and must be understood as such.

For these reasons, developers of large projects proceed step by step, increasing their certainty and knowledge with each step. The project cannot be financed without necessary federal and state permits, particularly the certificate of public convenience and necessity from the FERC. Before the sponsors can apply to the FERC, they must secure conditional commitments from shippers, the users of the pipeline, in a FERC regulated open season. Before the open season can occur, the project sponsors must conduct field work and further engineering so they can provide for the open season a reliable number for the cost and in service date of the project. Stage by stage, information is gathered, customer support garnered, and the necessary authorizations secured. Thus, the project takes on definition and specificity.

Because of the very large cost of the project and the long time before gas starts to flow through the pipeline, no prudent corporation can or would make a certain commitment to invest billions of dollars so early in the project’s life cycle. In fact, an investor today would simply not know precisely how large a commitment it would need to make. The size of that commitment will become known only as the project advances through the stages to project sanction. Work commitments for large projects are never unequivocal; there is simply too much uncertainty and risk to provide an unconditional promise.

Recognizing this reality, the state sought a meaningful way to move the project down the road towards project sanction. The work commitments obligate the project sponsors to advance towards that goal but also recognize that unforeseen events could delay or even, at the extreme, obstruct the project. The work commitments clause is a careful balance between initiating and advancing the project and recognizing the realities that could delay the project. As a set of work commitments, they compare favorably in a survey of comparable work commitments on large projects around the world (See Section 4.7.3.1).

The work commitments will be performed in conjunction with the step by step project process laid out earlier in Section 3.5. As the project is advanced through engineering and design, the open season, the FERC certificate and other agencies’ permitting processes, and ultimately to project sanction, the cost and design of the project become much more certain. What the sponsors have set forth as the project process corresponds to industry standards for the project life cycle. (IPA Institute, 2005 and Flybjery et al., 2003).

As the project advances through the stages of its development, the state through its membership in the mainline entity will be a participant in the major decisions of project development. The ANGPC, a state-owned entity, will be the state’s member of the management committee of the mainline entity. The major decisions, including budget, will be reviewed and approved by that committee. As such the state will have access to the budget, engineering and field reports, plans for securing regulatory approval, and the construction plan itself. A 20 percent share of the money being spent will be the state's own money so the state will have every incentive to be vigilant and interested in the activities of the mainline entity as it steps through the process. Unlike TAPS, the state will be at the table, gaining information, speaking to the issues, and voting on a wide variety of critical matters to ensure the work commitments are upheld.

4.7.3.1 Comparison of Work Commitments with Other International Projects

In comparison to other international projects, work commitments are not common for oil or gas pipeline, or LNG projects which have as the goal to market identified large oil or gas resources. There are only a few large international integrated projects based on resources which have already been discovered[59]. The following projects were reviewed to understand how the work commitments provisions in the contract compare with arrangements in these large international projects:

- BP Construction oil and gas project in Azerbaijan
- Shell Sakhalin oil and gas project
- Mobil Qatar LNG project
- Kashagan (North Caspian Sea) project in Kazakhstan.[60]

It should be noted that each project is unique; however, based on the information reviewed, all of these projects have work commitment provisions that are generally inferior to the proposed contract.

Compared to the contract provisions, the production sharing agreement for all the four projects:

- fail to have a specific work program on the pipeline component of the project,
- fail to have a start date for the initial studies on the project,
- fail to have a specific provision that the agreement can be terminated in case companies are not diligently implementing the pipeline program,
- fail to have a specific project description and time table as provided in Alaska under the qualified project plan, and
- take the year to year progress on the project subject to annual work programs which are at the discretion of some or all of the private investors in the consortia.

The AIOC oil and gas project goes through Georgia and Turkey, as well as Azerbaijan. The prior project approval of all three governments is a precondition to any work being obligated by the investors. In the contract provisions, there is no such pre-condition with respect to prior approval by Canada.

[59] A complete search of the Petrocash Data Base was carried out in order to identify the relevant information.

[60] The Kashagan project was evaluated because of the large oil discovery which was recently made there.

In Sakhalin, the start of any activities is subject to all approvals and licenses first being granted by Russian and local authorities; again no such pre-condition exists in the contract provisions. In the case of Sakhalin, there is even a money-back guarantee to investors if approvals and licenses are not obtained. Furthermore, in Sakhalin there is a specific clause permitting Shell to abandon the project without consequences after two years.

In Kashagan-Kazakhstan there is no pipeline obligation at all, despite the land-locked nature of the country and the essential requirement to export oil by pipeline.

Part of the reason that work commitments are not as strong in these four countries is that the contracts for these countries are for limited periods. Therefore, production has to begin well before the end of the contract period to enable an investor to recover their investment and make the investment worthwhile. Oil and gas leases in Alaska, however, do not have a fixed period of time which makes it essential to have strong work commitments as provided under the proposed contract.

4.7.4 Alignment

The parties to the contract recognize that Alaska's participation in the project has multiple benefits. This participation improves the project economics to the sponsor group and it causes the state and the sponsor group to be aligned with a goal of building and operating a successful project. For example, the state would be taking possession of its royalty gas and receiving the production payments as gas, not cash, so likely disputes about the value of that gas would be avoided. The state would make agreements for the sale or other disposition of state gas and have the responsibility to obtain the best terms it could for the gas. The state no longer would derive its revenues secondarily from transactions and pricing decisions made by others. Because Alaska will have the responsibility to market its own gas, the state also negotiated for special transportation rights (Article 10) to ensure that it would have access to capacity on the pipeline to move its gas to market. These rights ensure that Alaska can move its own gas to market on equal footing with the producers.

Ownership of 20 percent of the project further aligns the interests of the state and the sponsor group, in contrast to the TAPS where transportation costs of the pipeline and marine tankers reduce the state's revenues, and there are little to no offsetting revenues from the transportation system to the state's treasury. With state ownership in the project, the state will have capacity that closely matches its share of the gas, and operating revenues from its ownership share of the project. The state and the sponsor group will jointly make decisions on construction and operating costs for the project. Transportation costs will reduce the revenues from gas sales but the parties will have revenues from their ownership share of the project to offset some of the transportation costs.

4.7.5 Dispute Resolution

The state and the producers have been involved in a number of protracted and expensive legal disputes over oil prices, taxation, audits, and similar items for oil production and the TAPS. To avoid this situation with the gas project, the contract calls for mandatory dispute resolution (Article 26). The contract and certain exhibits lay out in detail the arbitration procedures to be used to resolve any disputes between the parties. The state, in recognizing the value of this clause, also waives its immunity to the mandatory dispute resolution procedures and the article. To further support the mandatory arbitration provision, Article 27 prevents the state from initiating any action that challenges the constitutionality, validity, legality and enforceability of any part of the contract, the SGDA or the authorization act.

4.7.6 Point Thomson Unit

The PTU has been in existence for 29 years, and encompasses approximately 106,200 acres of the eastern portion of the North Slope. Within the PTU, the Thomson Reservoir is known to contain at least eight tcf of gas and 400 million barrels of gas condensate and oil. Shallower Brookian resources within the PTU contain hundreds of millions barrels of oil.

The State of Alaska owns the entire subsurface estate within the PTU. There are 25 lease-holders with oil and gas rights within the PTU. Four of the 25 lease holders own over 98 percent of the PTU on a surface-acreage basis; EM owns almost 53 percent of the surface-area, BP holds 29 percent, Chevron U.S.A. Inc. (Chevron) holds 14 percent, and CP holds rights to almost 3 percent.

The rights of the lease holder and the state are set forth in applicable statutes, regulations, leases, and the PTU unit agreement. The PTU unit agreement and state regulations require that the PTU lessees periodically submit a unit plan of development for approval by the department of natural resources (ADNR). Any plan of development must protect the public interest based on the following criteria: promote the conservation of all natural resources, prevent economic and physical waste, and provide for the protection of all parties, including the state. Factors to be considered in evaluating a plan of development include environmental costs and benefits, geologic and engineering characteristics, exploration history, development and exploration plans, economic costs and benefits to the project, and any other relevant factors.

Since the inception of the PTU, EM (the PTU Operator), has submitted 22 plans of development to the ADNR. None of the plans committed to develop the hydrocarbon resources within the PTU; instead the plans specified studies needed to determine the commercial viability of hydrocarbon production. The latest plan (22nd POD), stipulated that construction of a natural gas pipeline is necessary before development of the PTU. The ADNR disapproved this plan and placed the unit in default for failure to submit an acceptable plan. EM has until May 31, 2006, to cure the unit default by submitting an acceptable plan.

Article 23 of the SGDA addresses the development of the PTU. Article 23 commits the PTU producers to provide a minimum of 500 million cubic feet per day of PTU gas to the project. The producers are required to apply to the Alaska Oil and Gas Conservation Commission for issuance of pool rules to authorize the field gas off-take rate for PTU gas within six months of the effective date.

Under the contract, the state agrees to temporarily suspend enforcement actions on the PTU, this includes suspending action to terminate the PTU, not enforcing any obligations that the PTU owners prepare and obtain approval of a plan of development for the PTU, or alter or modify the rate of development or operations of the PTU. The state's suspension would last until the date of initial delivery of PTU gas into the gas line. Within nine months of that date, the PTU owners are required to submit a plan of development.

If the contract is terminated or the producers fail to satisfy their obligations, the state can terminate the temporary suspension, in which case the PTU owners would have an opportunity to cure the unit default or file their appeal. In addition, they would need to meet certain obligations on the number and timing of development drilling that is required to retain the leases. These obligations include development drilling in the PTU within one year, drilling seven development wells in the PTU within three years, and submitting a plan of development.

Some parties have suggested that the state should take back the PTU leases from the current leaseholders and award them to a new party that might develop the lease sooner than the current leaseholders. The state has considered such an action but came to the conclusion that successfully pursuing this course of action could take a minimum of five years and would be vigorously opposed by the current leaseholders. If the state succeeded and took control of the leases, existing law requires that the leases be offered in a competitive lease sale. The state could not re-lease the properties to a party of its choice without following the established process for bidding on leases. After the conclusion of the litigation, the established process could take six months to a year before the leases would be awarded although, when reoffered, the lease terms could include specific and timely development commitments.

4.7.7 Legal Issues

The following subsections briefly discuss some important legal issues with respect to the project including the ability of the state to enter into a contract, state tax powers, and issues related to competition and antitrust.

4.7.7.1 Contract Issues

The SGDA and the proposed contract present an important legal issue concerning whether the state can monetize its huge gas resources by entering into a contract that will establish the tax obligations of the sponsor group for a set period of time. This type of contract is referred to as a “fiscal contract.”

Because of the fundamental importance of this issue, the attorney general provided legal advice concerning whether the state can enter into a fiscal contract with the sponsor group. The attorney general concluded a fiscal contract, such as the one proposed, is permitted under provisions of the Alaska constitution. The advice is based on an extensive review and examination of the contract clause of the United States constitution and Article IX, sections 1 and 4, and Article VIII of Alaska’s constitution.

The attorney general first examined whether, as a general principle, states can enter into long-term fiscal contracts that cannot be modified by subsequent legislative enactments. The contract clause, Article 1, section 10, of the United States constitution provides that no state shall pass any law impairing the obligation of contracts. The attorney general concluded that states have the inherent sovereign power to enter into long-term binding fiscal contracts if the power is not limited by the state’s constitution. If a state can, and does, properly enter into such a contract, it can be held to those terms under the contract clause despite subsequent state legislation seeking to modify tax rates that would otherwise affect the fiscal obligations of the parties to the contract.

Through a series of cases, starting in the early 1800s, the United States Supreme Court determined that the contract clause applied to fiscal contracts in which state legislatures agreed to specific tax obligations. When the state legislatures later sought to modify the contractual tax rates, the court found that the states were bound by the tax rates specified in the contracts.

The Supreme Court said that there are certain inherent and essential elements of sovereignty that can never be contracted away—"reserved powers." For example, a state cannot contract away its police power to determine what criminal conduct is. But the power of taxation is not a reserved power. Rather, it is incidental to the exercise of governmental functions and exists to facilitate inherent and essential governmental functions.

The Supreme Court recognized that states can enter into fiscal contracts and still perform essential government functions. Thus, as a general principle, the court determined that states have authority to enter into fiscal contracts that will be subject to the contract clause, as long as it is permitted in their state constitutions.

Next, the attorney general examined whether the Alaska constitution provides the authority for the State of Alaska to enter into a fiscal contract that would be enforceable under the contract clause of the United States constitution. Did the framers of the Alaska constitution intend Article IX to limit the Alaska legislature's inherent authority to approve long-term binding fiscal contracts that are necessary to provide incentives to monetize Alaska's resources? The attorney general found that the finance and taxation article of the Alaska constitution, Article IX, permits the state to enter into an enforceable fiscal contract to monetize its gas.

The history of Article IX shows that the framers of Alaska's constitution chose to give the legislature the flexibility to approve fiscal contracts providing for tax exemptions by general law. The constitutional convention specifically considered and rejected a provision put forward by the National Municipal League (NML) that would have prevented the legislature from approving fiscal contracts. The NML provision prohibited any surrender, suspension, or contracting away of taxing power.

The restrictive NML model provision arose from concerns that a number of states had restricted their power to tax businesses such as banks and railroads through approval of tax rates in corporate charters. As times and economic fortunes changed, a number of these states attempted to repeal the corporate charters and impose additional taxes on these businesses. The businesses sought, in turn, to enforce the corporate tax rates through the contract clause contained in the United States constitution. As discussed earlier, the United States Supreme Court consistently held that states which had contracted away their taxing power could be held to those contracts as long as their state constitutions permitted it.

A number of states reacted to the Supreme Court's decisions by enacting provisions in their state constitutions prohibiting their legislatures from contracting away the power of taxation. The wording of these prohibitive provisions varies slightly among the states, but typically provides that: "[t]he power of taxation shall never be surrendered, suspended, or contracted away." This prohibitive language was adopted by the NML, and was a part of the model state constitution that was used as the template for the Alaska constitution.

Under the NML language, the Alaska legislature would have no authority to approve a fiscal contract. Indeed, consultants to the constitutional convention noted that this provision was included in the model state constitution precisely because, without it, Alaska could be bound by the types of fiscal contracts other states had authorized.

It is a settled principle of public law that one legislature cannot bind another and that government of a state cannot contract away its police powers. The power to tax is not considered inalienable, however. In granting exemptions, one legislature may bind another and thereby lose for the state its power to tax. According to the consultants, the object of the provision was to prevent a state from exempting, "particularly by contract," corporations from taxation. But the framers of the Alaska constitution rejected the prohibitive provision and adopted the clause now contained in Article IX.

Article IX, section 1, gives the Alaska legislature authority to suspend or contract away taxing power by providing tax exemptions by general law. It reads: "[t]he power of taxation shall never be surrendered. This power shall not be suspended or contracted away, except as provided in this article." Section 4 of Article IX, in turn, permits the legislature to grant tax exemptions by general law.

The framers rejected the NML provision in light of Alaska's unique circumstances as a resource-rich but sparsely populated state without the local capital available to develop its resources. The history of the constitutional convention indicates that the Framers intended to provide the legislature with the flexibility to enter into fiscal contracts though enactment of a general law, such as the SGDA. The framers intended the constitution to be a forward-looking document that would provide the legislature with the tools to develop Alaska's resources.

Delegate Nerland, a delegate to the constitutional convention and chair of the committee on finance and taxation explained that the model state constitution was modified because "there would possibly be occasion and good justification in the future for such things as allowing an industry-wide exemption to encourage new industry to come in." The constitutional convention finance committee explained that "the power to tax is never to be surrendered, but under terms that may be established by the legislature, it may be suspended, or temporarily contracted away." This is consistent with the SGDA, which provides for a fiscal contract for a defined period of time.

This conclusion is also consistent with the natural resources article of the Alaska constitution, Article VIII. That article provides that it is the specific policy of the state to develop its natural resources and gives the state legislature authority to provide for utilization and development of natural resources.

The need to develop natural resources and bring in new industries was a continuing concern expressed both in the statehood act debates and the constitutional convention. When Alaska statehood was being debated in the United States Congress, one of the principal objections to statehood was that Alaska would not be able to economically support itself. For example, one of the opponents of statehood claimed that "Alaska is not capable of sustaining statehood unless it is heavily subsidized by the other 48 States of the Union." Even members of congress who supported statehood conceded that there would be difficult financial burdens without some special considerations of Alaska's unique circumstances.

To address the need for an economic base, Congress granted 103 million acres of federal land to Alaska as an endowment that would yield income to Alaska to meet the costs of statehood. The statehood land grant was considered "the foundation upon which Alaska can and will build to the enormous benefit of the national economy shared by her sister States."

Similarly, debates during Alaska's 1955 constitutional convention focused on developing the state's natural resources and attracting industry. The framers were keenly aware of the necessity of developing Alaska's resources because Alaska lacked the economic foundations of older, more established states. The framers included Article VIII in the constitution, stating that "[i]t is the policy of the state to encourage the settlement of its land and development of its resources by making them available for maximum use consistent with the public interest." The constitution thus provides the legislature with broad powers to take actions to utilize and develop the natural resources of the state.

The framers recognized that developing Alaska's resources according to the mandate of Article VIII might require an innovative tax regime, and this is reflected in their rejection of the highly restrictive NML model for the Article IX, the finance and taxation clause.

Indeed, fiscal contracts have been employed in Alaska to attract new industries during territorial days and since the constitution was ratified. For example, in 1949, the territory authorized the tax commissioner to enter into fiscal contracts for new industrial enterprises. Again, in 1957, after the Alaska constitution was ratified, the territory enacted an industrial incentive act that permitted businesses to apply for fiscal contracts to encourage new investments in Alaska. The framers of the state constitution had the foresight to understand that the state would in all likelihood need to be adaptive to changing conditions in order to attract the capital necessary to develop the state's economy. Alaska's constitution recognizes that there may be occasions in which the state may need to negotiate a fiscal contract that provides the necessary tax stability required to attract investment capital.

4.7.7.2 Competition Issues

Once built, the Alaska gas pipeline would likely be the only way to transport natural gas from Alaska's North Slope to market which would give the pipeline an effective monopoly on those transportation services. Public concern has been expressed over whether ownership of the pipeline by the large North Slope gas producers would create major problems in terms of competition. A related concern is whether a pipeline project not owned by the producers—an independent pipeline—would be preferable.

From an antitrust perspective, a careful analysis shows that two markets could be affected by competitive issues related to an Alaska gas pipeline. One market would be competition with respect to the transportation of natural gas from Alaska's North Slope. A second relevant market would be competition among sellers of natural gas in the downstream, destination markets where the gas ultimately is sold.

These are not new issues. Antitrust issues were raised in President Carter's Decision and a ban on producer ownership of the pipeline was imposed, only to be lifted by President Reagan when the ban provided to be an impediment to advancing the pipeline. Since that time, the structure of pipeline regulation has changed as have natural gas markets. Antitrust issues should be approached in a contemporary context because of advances in antitrust theory and recognition of newer regulatory regimes provided by the FERC process and

NEPA. Any new pipeline will be highly regulated from the perspective of both rates and access.

Under the current regulatory regime, FERC will regulate terms of access to the pipeline as well as its rates. FERC has announced it will review the application for a certificate of public convenience and necessity for authority to build the pipeline for any competitive issues that could arise. FERC has the power to impose conditions on the application to address any such issues. Competitive issues are taken into account by FERC in the decision about whether it is in “the public interest” to issue a certificate of public convenience and necessity for a new pipeline. However, FERC does not enforce the antitrust laws.

With respect to competition in downstream gas markets, each of the North Slope producers is an independent competitor and no one competitor today or in the future, is anticipated to have a large enough share of downstream market to affect natural gas prices. The regulation of interstate pipelines was revamped since the ANGTS was shelved such that FERC requires interstate pipelines to offer only transportation services and to offer access to those services on a nondiscriminatory basis. FERC specifically adopted regulations and policies that bar pipelines from favoring affiliated production in offering new or expanded capacity. A large body of case law has developed as FERC has applied these policies. FERC has also adopted standards of conduct that require gas pipeline affiliates to operate independently of their marketing and production affiliates.

As required by Congress, FERC has adopted specific regulations that control access to the capacity of an Alaska gas pipeline. These open season regulations, described in Section 4.4.1, are designed to establish a level playing field in terms of access to the pipeline. The open season regulations require a comprehensive disclosure of information about the pipeline’s design, capacity, and tariffs as well as the method by which capacity will be allocated among prospective bidders. These regulations are designed to place all prospective shippers, whether affiliated with the pipeline or not, on an equal footing.

4.7.7.3 Modern Antitrust Analysis of the Proposed Joint Venture

The gas pipeline project would be a joint venture between the producers and the state. The state’s lawyers applied modern antitrust analysis to the joint venture and concluded that the joint venture is consistent with antitrust laws—producer ownership of the pipeline would not violate antitrust laws. The analysis that follows addresses several important questions. First, is the basic purpose of the joint venture lawful? Second, is the collaboration likely to lessen competition substantially in any relevant market? Third, does the collaboration contain any unlawful “ancillary” restraints? In other words, are there conditions to the joint venture that are broader than necessary to achieve its legitimate purposes?

With respect to the first question, the basic purpose of the pipeline is to carry North Slope natural gas to Canada and ultimately the lower 48 states. That gas has been stranded for 30 years because of the absence of a means of transportation. With the gas pipeline, the owners of North Slope gas reserves, including the state, finally will be able to bring their gas to market. The supply of natural gas available to the lower 48 states will increase and the increase in supply will increase competition in the sale of gas in the lower 48 states. The purpose of the project is consistent competitive principles and lawful.

With respect to the second question, a producer gas pipeline does not appear likely to lessen competition substantially in any relevant downstream market. Currently, no gas reserves from the North Slope are being marketed to consumers. Thus, the pipeline's transportation of the gas to market can only increase competition in the sale of gas. It also appears extremely unlikely that any of the individual producers or the state alone would ever be in a position to build a separate pipeline in competition with the proposed gas pipeline. Thus, the fact that the producers and the state are collaborating in building the pipeline would not reduce competition in the transportation of gas from the North Slope.

As for competition in exploration activities, the construction of a gas pipeline should increase, not reduce, competition in that sector. Once a means to transport the gas to market is available, it should attract more exploration and development, plainly a positive competitive impact.

An answer to the third inquiry—the absence of anticompetitive constraints—will be reviewed once the LLC agreement is negotiated and presented for review. There is no basis for presuming the presence of anticompetitive constraint in advance. Antitrust review of the agreement will occur before the project is authorized. Any specific issues that arise can be addressed at that time.

4.7.7.4 An Independent Pipeline

The final issue to be addressed is whether a producer owned pipeline is likely to lead to substantially less competition in the transportation of gas from the North Slope than if the gas pipeline was owned by a company that is not so affiliated. One theory that has been advanced at the time of the ANGTS was that the producers would deny access to the gas pipeline to nonaffiliated shippers in order to eliminate competition in the downstream sale of natural gas. That theory was based on the structure of the markets and the regulatory world at that time.

As noted previously, since ANGTS, FERC has changed the structure of regulation by unbundling natural gas sales from transportation services. FERC also imposed a set of open season and nondiscrimination requirements on the gas pipeline industry. Detailed regulations on access, expansion, and nondiscrimination have been adopted specifically for an Alaska gas pipeline.

Economic analysis indicates that for a competitive difference to result from a producer owned pipeline, two conditions would need to occur. First, the producers would need to have the ability to deny access to the gas pipeline to non-affiliated shippers and, second, the producer's position in the downstream gas market must give it an incentive to block access to the pipeline. As explained above and in more detail in the antitrust advice that the state has received, (Appendix J), FERC and Congress have addressed the issues of access to the pipeline, proper sizing, and expansion. After reviewing the body of regulation and remedies, the state's lawyers have concluded that the producers could not lawfully discriminate in favor of their own affiliates in order to give them a competitive advantage *vis-à-vis* non-affiliated shippers.

Antitrust analysis also concludes that the producers would not have any incentive to withhold capacity from a from a third party shipper for anticompetitive purposes. As owners of the pipeline, greater throughput, whatever its source, generates more pipeline income and provides an incentive for the pipeline to attract third party shippers. Nor is there a contrary incentive to prevent third party shipment in the interest of eliminating competition in the downstream sale of gas. For such a contrary incentive to exist, one or more of the producers would need to possess market power in a relevant downstream market.

Only if they had such market power could they influence the prices they charge or that are charged in that market. None of the sponsor groups is projected to have inordinate market power when the pipeline becomes operational. Their shares in 2015, for example, are expected to be BP–7.3 percent, ConocoPhillips–5.8 percent, and ExxonMobil–7.9 percent. These market shares are far below the level necessary for any one of the companies to be able to exercise market power. None thus has an incentive to block third party shipments in an effort to maintain prices above a competitive level. Finally, it should be noted that as sellers of natural gas downstream, each of the producers competes with the others. For this reason, it would be inappropriate to cumulate their shares in a market power analysis.

In conclusion, it could be argued that a producer owned pipeline has a greater incentive to control the cost of construction and operation of a gas pipeline than an independent pipeline because producers would earn returns on both the transportation and sale of gas. Keeping costs lower should result in a lower tariff and thereby a greater profit on gas sales for a producer owned pipeline. However, an independent pipeline earns revenues only from transportation. Since potential cost overruns in construction and operation may be factored into the tariff structure, the incentive to minimize tariffs may be lower for an independent pipeline owner than for a producer owned pipeline.

4.7.8 Regulatory Issues: FERC and RCA Jurisdiction

Article 8.1-8.3 of the contract establishes the parties' position concerning FERC, NEB, and RCA jurisdiction over the project.

In response to the sponsor group's insistence that the contract commit the parties to a common position regarding the presence of FERC and NEB jurisdiction and absence of RCA jurisdiction, Articles 8.1to 8.3 were negotiated. Articles 8.1 to 8.3 do not change existing law but instead express the parties understanding of established jurisdictional boundaries and requires the parties to support the exclusivity of FERC and NEB jurisdiction at each agency respectively. If the RCA does not respect those boundaries and endeavors to assert jurisdiction, the parties will work together to confirm the absence of its jurisdiction. Solutions might include judicial or legislation action. In the event that the RCA takes action inconsistent with FERC principles for regulation of interstate pipelines or, in the absence thereof, commercial agreements between the party for non-jurisdictional facilities, and in the absence of other solutions, and after nine months' notice, the sponsor group can pursue a claim against the state for any additional cost to the project from such jurisdiction through the dispute resolution process and the state may, in limited circumstances, be required to indemnify the producers for a loss if a loss can be established.

This clause should be viewed in the context of established law. The FERC has exclusive and paramount authority over the authorization and operation of interstate natural gas pipelines. It must be noted that the FERC's comprehensive authority over gas pipelines contrasts sharply with its limited rate jurisdiction over oil pipelines. Oil pipelines do not need the authorization of the FERC to construct facilities, to operate those facilities, or to exit the business. For oil pipelines, FERC's only function is to regulate their rates and even there, as in the case of

TAPS, it has parallel jurisdiction with the RCA over the interstate and intrastate rates respectively.

The picture is entirely different for interstate gas pipelines such as an Alaska gas pipeline. After reviewing a prospective pipeline's application that must satisfy its extensive requirements, the FERC grants a certificate of public convenience and necessity that authorizes an interstate gas pipeline to construct its facilities and transport gas at regulated rates. FERC even regulates the rate for gas shipped on the mainline even if some of the gas is destined for intrastate destinations. FERC also regulates the terms of access to interstate gas pipelines through its open season requirements.

The jurisdiction of the FERC over the gas treatment plant is confirmed by the substantive requirements of Order 2005 and Order 2005-A where FERC, following the mandate of ANGPA, established open season requirements for the gas treatment plant as well as the mainline. Finally, based on the current state of knowledge and the integral role that the gas transmission pipelines play in the Alaska gas pipeline system, it appears likely that the FERC will also assert jurisdiction over the gas transmission pipelines which transport gas from the units to the GTP or the mainline. Based on what the state knows today, the gas transmission pipelines do not appear to qualify as gathering lines that are exempt from FERC oversight.

There is one area where the RCA clearly does have jurisdiction. The state worked with Congress to confirm that the RCA would have jurisdiction over any lateral that connects with the mainline to provide service inside Alaska. Section 106(a) of ANGPA states that the FERC does not have jurisdiction over such a lateral. The RCA, accordingly, would have authority to approve construction of the lateral and regulate the rates it charges for in-state deliveries. The contract is also clear that any such lateral is not part of the project for purposes of the contract. Thus, RCA jurisdiction has been confirmed and preserved.

If the RCA believed that it had jurisdiction over aspects of the project that are solely the province of the FERC, disputes could arise that might delay or add cost to the project. The sponsor group felt strongly that the state and the sponsors should be aligned in confirming the clear jurisdiction of the FERC and the clear absence of jurisdiction by the RCA. That is the intent of the clause.

The state and the sponsor group negotiated language that recognizes a remedy in certain circumstances if the RCA does assert jurisdiction over the project. In that event, the parties will work together to preserve federal jurisdiction on the project and to avoid the inefficiencies of conflicting regulatory schemes. The parties could, for example, seek a declaratory order establishing the proper jurisdictional boundaries. Or state or federal legislation to the same end might be pursued.

As a last resort, the sponsor group insisted upon provisions that would give a right to pursue a claim under the dispute resolution procedures for any "loss" that they might suffer from an assertion of jurisdiction by the RCA over the project. Their right to recover a loss is limited in several ways. First, there is no loss if the RCA acts consistently with FERC policy for jurisdictional facilities or, in the unlikely event there were non-jurisdictional facilities, with the commercial agreements that the parties had negotiated to govern such facilities. Assuming that it is shown that the RCA's action is inconsistent with those standards, the contract contains a limitation on damages and remedies that would apply. Article 37.2 provides the parties can not claim or collect a loss that equated to "(a) any consequential or incidental damages, including lost profits; or (b) any special or punitive damages." Thus, the contract would foreclose a claim that the pipeline or GTP made less money or lost profits because of RCA action. In the state's view, it is difficult to foresee how a claim under this clause would ever give rise to material liability for the state. If a claim succeeded despite the procedural and substantive requirements that must be satisfied, the state is obligated by contract to reimburse the party for the established loss.

4.7.9 Transportation Issues and the Highway Use Agreement

Construction of the pipeline will place heavy demands on Alaska's surface transportation system. The anticipated logistics operations necessary to support project material movements within the construction schedule pose the potential for significant impacts on transportation infrastructure.

In Alaska, most vehicles used on highways are owned and operated by private individuals and firms, while most highway infrastructure is funded and maintained by the public sector. This stands in contrast to railroads, which are self-sustaining. Unfortunately, Alaska's two railroads have relatively limited zones of influence reaching from Seward to Fairbanks and Skagway into Yukon thus forcing highways to play a significant role in heavy-haul freight movements that would otherwise lend themselves to railroads. Highway transportation in Alaska plays a significant role in two major areas: providing personal mobility and facilitating freight movement. Understanding this dual nature of highway travel is important in understanding how public policy affects the efficient use of the highway network.

The intensity of freight movement during pipeline construction will increase truck volumes and freight tonnages to a level above and beyond roadway life-cycle design as well as, in specific instances, the physical capacity of the infrastructure. To fully realize and mitigate the potential impacts of gas line construction on our transportation system, the department will enter into a Highway Use Agreement (HUA) with the mainline LLC. The HUA will address, amongst other provisions:

- Assessment and selection of necessary infrastructure improvements;
- Cost share principals for capital projects;
- Compensation for increased maintenance and operations;
- Airport facility safety and security issues;
- Roadway safety, traffic control and congestion mitigation;
- Permitting, truck weight and size;
- Right-of-way, access and encroachment;
- Utility relocation.

The most significant transportation impact is the necessary capital investment to upgrade and maintain the highway system. There are primarily two types of pipeline induced transportation projects—those transportation improvements that will occur prior to the start of pipeline construction, and those projects that will occur after pipeline construction.

Capacity-related infrastructure improvements will typically need to be constructed and in-place prior to the start of pipeline construction. Examples typically include bridges that lack capacity or highway surfaces near the end of their useful lives. Safety related projects might warrant up-front mitigation where interaction of construction traffic and non-construction traffic pose irreconcilable concerns. Safety related projects include passing lanes or turning lanes into construction camps, freight yards and terminals, passing lanes, and safety turnout areas.

Other improvements will become necessary as pipeline construction progresses and the transportation system feels the brunt of thousands of additional axle loads in a relatively short period of time. Roadway maintenance will occur during the on-going pipeline construction in an effort to sustain an appropriate level of service, however it is expected that much of the longer-term surface rehabilitation will take place once pipeline construction is concluded.

The ability of existing airports to efficiently support air transportation freight and personnel movements will depend on a number of factors such as runway characteristics, navigational aids, fuel and ground handling facilities and forecasted demand. Some improvements will be necessary.

Discussions with the sponsor group suggest the highway system will be used extensively throughout the pre-construction and construction periods. Logistics will likely rely on several port communities to access different segments of the gas pipeline, and movements from these ports to the interior will utilize a combination of rail and highway, or just highway transport. Most of Alaska’s major highways known as the NHS or National Highway System will see increased truck traffic, even in Southeast Alaska that will serve as a portal to Canadian segments of the gas pipeline.

Based on the department of transportation’s understanding from the anticipated logistics plan and assessments by the department, the cost of transportation projects that need to occur prior to pipeline construction may approach $400 million. The cost of system rehabilitation after construction may approach $800 million. These capital costs overwhelm the department’s annual expenditures, which over the past five years, has averaged less than $700 million. The cost of transportation enhancements and rehabilitation will be strongly influenced by the final logistics plan that will be developed in coordination with the department. Alaska’s railroads will be called upon to the extent possible and are in a strong position to relieve traffic along parallel roadway infrastructure. The final logistics plan will establish mobilization routes, freight volume, tonnage size and weight standards, and frequency of freight traffic as well as expected maintenance levels and congestion mitigation. There is a plethora of issues yet to be resolved that will have tremendous bearing on logistics such as pipe diameter, length and wall thickness, haul lengths and point of origin; extent of access by sea to Prudhoe Bay; spreads and locations of compressor stations; final design of the pipeline, cut/fill and embankment requirements, railroad capacity and extensions.

Federal funding for Alaska through 2009 is now set in law, and will play a limited role in preparing the highway infrastructure for the gas pipeline construction. Due to several factors, this funding is limited, and much of it will be directed to projects that address urban congestion, safety, or shared with local governments. To the extent possible, the department has guided some of this funding, along with general fund appropriations to the benefit of the gas pipeline construction, but the job is by no means complete.

Requests for additional federal funds, though technically possible, come with significant constraints. The rules governing federal highway funding are significant, and require a methodical step-by-step approach. The result is a simple project such as a bridge replacement can take five or more years. This same project with state or mainline LLC funds might be accomplished in two years. Further, Alaska's congressional members have recently warned the legislature that new earmarks are less likely due to a combination of factors, thus this avenue of financial support is not likely to close the funding gap.

The State of Alaska has finite capacity to support the anticipated financial burden of road construction as well as the physical capability to perform the work on short order. The department's capital budget and workforce is applied toward community and regional transportation projects throughout the state and the diversion of significant amounts of resources toward pipeline related infrastructure would quickly become politically intolerable. Instead, transportation projects deemed indispensable to the pipeline will be evaluated to ascertain the public-private (state or LLC) financial share based on the project's level of public utility versus the singular interest of the LLC. Additionally, a base-line analysis of roadway infrastructure will be conducted prior to the start of pipeline construction. This baseline will be used in identifying the level of LLC financial responsibility in road surface degradation over the construction period. Project delivery is resource dependent. It is anticipated that department staff, regulatory agencies, technical consultants and construction contractors will be nearing peak capacity as the pipeline project progresses. Financial constraints and resource availability will pose a risk to the project schedule as delays in transportation infrastructure development and unmitigated bottlenecks may delay critical pipeline elements.

The department is charged with providing the necessary support of pipeline construction while providing for the transportation needs of the public. The magnitude of the project distributed over the relatively brief timeline will inevitably induce capacity strains and unavoidable congestion with potential for short-lived system degradation. The mitigation of these concerns will be dealt with as practicably as possible through the HUA. With thorough planning and proper contingencies, pipeline logistics impacts will be manageable. With proper strategic planning, the potential exists for significant portions of the transportation investment to expedite projects that are within the long-term statewide transportation interest.

5 Evaluation of Options

Of all the options to develop North Slope natural gas, the project that has the greatest chance for success is the one submitted by the major oil companies that would construct a pipeline from the North Slope to Alberta. Other options, including a LNG plant and a combination of LNG and gas pipeline do not provide nearly as much value to the state or the companies. Section 5.1 presents detailed analysis and results of the project submitted by the Sponsor Group. Section 5.2 outlines two other projects, evaluates all three projects on similar economic indicators, and presents a summary of all applications under the Stranded Gas Act.

5.1 Analysis of Balance of Fiscal Principles

5.1.1 Summary and Conclusions

The goal of the SGDA is to ensure that the contract will make the project more competitive. This ensures that the project is more likely to proceed after a period of feasibility studies and regulatory approvals. At the same time, the SGDA requires the commissioner to structure the fiscal terms in such a way that they provide significant revenues to the state and affected communities under favorable economic conditions.

The SGDA also provides guidelines for restructuring the fiscal terms. The SGDA prescribes that the fiscal share of project revenues that Alaska receives should become higher if prices are higher and costs are lower than expected, while the state should take a smaller share in the early years and a larger share in later years.

The proposed contract complies with the balance of principles required under the SGDA. The proposed contract makes the project more competitive. The Alaska gas project was compared with 60 other large oil and gas projects in the world in order to ensure that the profitability is competitive. In general, the profitability of the Alaska gas project is less than average compared to competing projects. The internal rate of return (IRR) of the Alaska gas project is low compared to other projects. Due to the large size of the project, however, the absolute size of the profits and net cash flow are very favorable.

In order to make the project more competitive, the proposed contract results in a higher real rate of return than under the 2005 fiscal terms. For a project delivering gas to Alberta, the real rate of return improved from 11.8 percent with the 2005 fiscal terms to 14.0 percent (at the $3.50 per mmBtu stress price).

This increased rate of return was achieved through risk sharing and participation by the State of Alaska. Under the proposed contract, the state takes all gas royalties in kind and also converts the severance tax into a payment in kind. This results in the state receiving almost 20 percent of all the gas from the project.

The state directly assumed the obligations to transport and sell its share of the gas. The state will also participate in 20 percent of the investments in the GTP and pipeline.

This means that the sponsors now have to invest in 80 percent of the project in order to receive 80 percent of the gas, rather than investing in 100 percent of the project in order to receive 80 percent of the gas. This is much more profitable for the investors as they are required to invest less in order to receive the same net revenues.

At the same time, the state receives a steady stream of pipeline tariff revenues as a result of its investment. This provides ongoing stable income for the state, which will not be affected by the level of gas prices. This is good for the state.

Therefore, this is a deal that is good for the sponsors, the state, and the affected municipalities. It is the best opportunity for a cost effective project to move forward in the shortest possible time. It improves the rate of return without giving up any significant revenues.

This is far better than the traditional way of making a project more competitive, which is to lower the royalties and taxes that need to be paid. This traditional method is not a viable option for Alaska. In order to achieve the above increase in the rate of return, the royalties and taxes would have to be lowered so much that the contract would become very unattractive to Alaska.

As a result of the proposed contract, the annual Alaska revenues will be high. The estimated revenues under a range of gas prices (Chicago city gate) in real 2006 dollars are as follows:

- At low gas prices of $3.50 per mmBtu: $1 billion per year;
- At average gas prices of $5.50 per mmBtu : $1.7 billion per year; and
- At high Chicago gas prices of $8.50 per mmBtu: $2.7 billion per year.

What should be highlighted is that Alaska will still receive very high total revenues even if gas prices are relatively low. In other words, under low gas prices the proposed contract is favorably balanced for Alaska but offers poor returns for investors. This also means that the terms result in favorable profits if gas prices are high and costs are average.

The negotiated terms reflect very competitive terms from an international point of view. Jurisdictions that transport their gas over large distances, either by long distance pipeline or as LNG, necessarily have to adjust their terms to overcome these high transport costs. The overall government take that governments achieve in these circumstances is about 48 to 57 percent. Alaska fits right in the middle of this range.

It is very important that fiscal certainty is included in the proposed contract. In the absence of fiscal certainty in the stranded gas contract, it is possible that adjustments would be made in the future by a legislature acting in good faith that in fact would erode much of the profits originally required to make the project competitive. At the commencement of project operations, all capital expenditures of the investors will have become sunk cost. Therefore, the sponsors no longer have the option to not proceed with the project.

In other words, the structure of fiscal certainty in this proposed contract reduces investor exposure to:

- Significant possible erosion of value under average and high prices to the point where the project becomes unattractive, when taking into consideration the capital invested; and
- Very significant downside price and cost overrun conditions.

For such a large project, investors simply cannot take this risk. Fiscal certainty is absolutely required if this project is to be realized.

In the remainder of this section, the economics of the project will be evaluated in more detail.

5.1.2 Introduction

Section 43.82.210(b) of the SGDA requires the commissioner to develop terms in a manner that attempts to balance eight principles set out in that section. The first six of these principles are economic-financial principles. This section of the report provides a general discussion of these six economic-financial principles, which are as follows:

(1) The terms should improve the competitiveness of the project in relation to other development efforts aimed at supplying the same market.

(2) The terms should accommodate the interests of the state, affected municipalities, and sponsors under a wide range of economic conditions, potential project structures, and marketing arrangements.

(3) The combined share of the economic rent to the state and affected municipalities should be progressive.

(4) The combined share of the economic rent to the state and the affected municipalities should be back end loaded.

(5) The share of the sponsors should compensate the sponsors for risks under a range of economic circumstances.

(6) The terms should provide the state and affected municipalities with a significant share of the economic rent when discounted to present value under favorable price and cost conditions.

Following is a brief discussion of the methodology that was used.

Wide Range of Economic Conditions and Project Structures

The PVM model was used to perform this analysis. The details of this model and analysis can be found in two reports: “Economic Analysis of the Alaska Stranded Gas Fiscal Contract” (van Meurs, 2006a) and “State Risk Sharing and Participation and Related Issues” (van Meurs, 2006b).

A wide range of economic conditions and project structures were evaluated. The following economic conditions were analyzed:

- Gas price (Chicago city gate): the main scenarios range from $2.50 to $8.50 per mmBtu.
- Costs: the main scenarios range from 90 percent to 150 percent of base capital and operating expenditures.
- Inflation/Escalation: the main scenarios were zero percent (constant 2006 dollars) and nominal at two percent inflation and escalation of costs and prices.
- Financing: with and without debt financing at different levels of equity and different levels of cost of debt and equity.

The following forecasts for the Chicago gas prices (in 2006 dollars) were used as representative of the currently prevailing conditions of major oil company views about the future:

- A low forecast of \$3.50 per mmBtu (the "stress price");
- An average forecast of \$5.50 per mmBtu; and
- A high forecast of \$8.50 per mmBtu.

Major oil companies currently use low price forecasts of \$20 to \$25 per barrel of WTI in order to test the economics of investment projects. This corresponds with the low forecast of \$3.50 per mmBtu in Chicago. Extensive analysis was done on this stress price.

The PVM model uses an assumption of a \$21.2 billion midstream project in 2006 dollars, with a cost variation of 90 to 120 percent as prevailing cost conditions. Furthermore, the PVM model assumes upstream capital and operating costs.

The following project structures were analyzed:

- A project ending at the BC/Alberta border where it connects to the Alberta Hub; and
- A project ending in Chicago.

It is assumed that a share of the gas will be delivered for in-state use in the State of Alaska under both project structures. It is also assumed that the wellhead prices in this case will be the same. Therefore, there would be no economic impact on upstream revenues.

There is considerable difference in the economics of a project ending in Alberta and in Chicago. At this time, it appears that a share of the gas can be delivered to Alberta without need for further pipelines based on an estimated takeaway capacity of two bcf/day in 2015. For the remaining gas, takeaway capacity needs to be secured in order to deliver the gas to the Chicago area. This means the economics of the actual project will be somewhere between the Alberta and Chicago economics.

Share of Economic Rent

An important concept is the combined share that the state and municipalities receive from the divisible income. Divisible income is the gross revenues less all capital and operating expenditures. It is the "pie" that governments and companies share through the fiscal system. In the stranded gas contract, the divisible income is called "economic rent."

In order to analyze the share of the economic rent, two concepts were modeled:

- *Total Government Take*: includes government take in Alaska, U.S. Federal Government, lower 48 states, and Canada. This is the share that all these governments together receive from the divisible income.
- *Alaska Take*: includes the government take by the State of Alaska and the affected Alaska municipalities.

Compensation for Risk under a Range of Economic Circumstances

Seven profitability indicators were used to evaluate the compensation to the investors for investing in the Alaska gas project:

- The internal rate of return ("IRR");
- The net present value discounted at 10 percent ("NPV10");
- The profitability ratio discounted at 10 percent ("PFR10");
- The undiscounted net cash flow ("NCF");
- The NPV10 per barrel equivalent ("NPV10/BOE");
- The NPV10 over undiscounted capital expenditures ("NPV10/Capex"); and
- The NCF per barrel equivalent ("NCF/BOE").

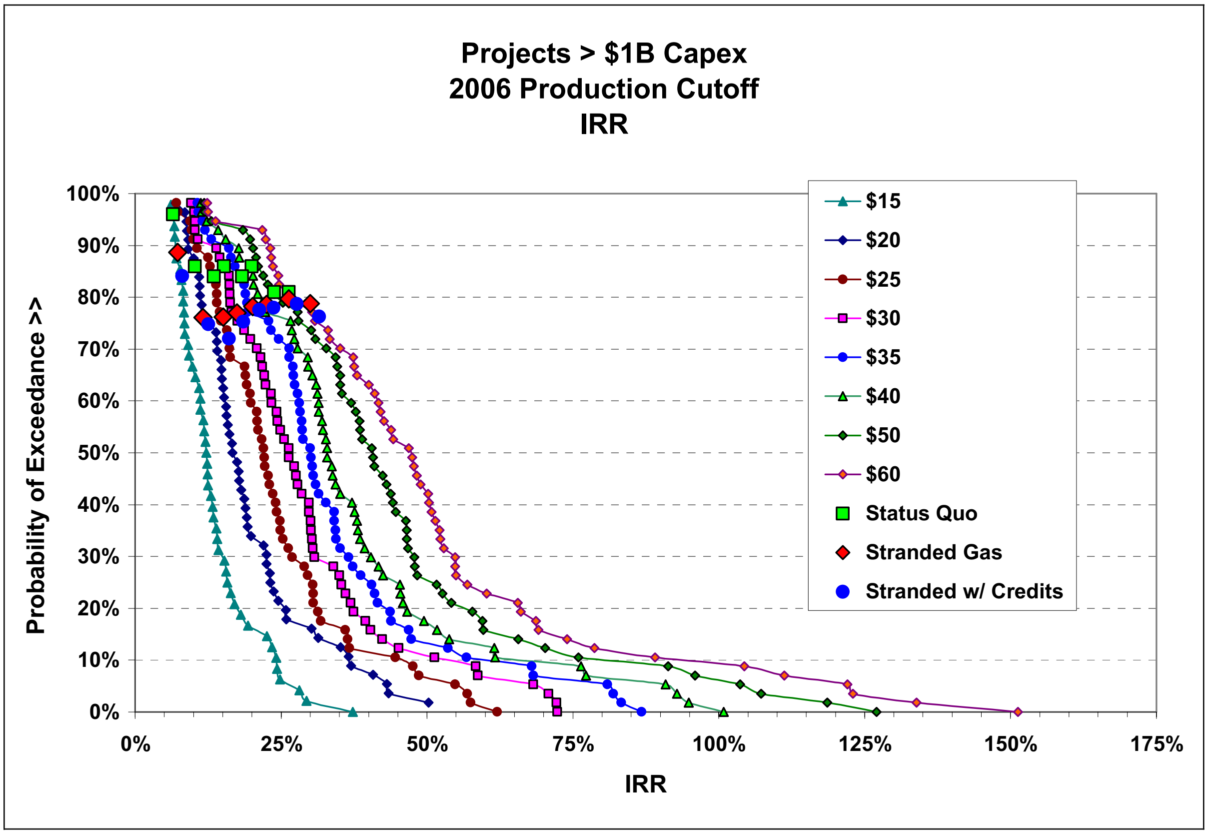
The importance of each of these profitability indicators is explained in more detail in the Economic Analysis Report (van Meurs, 2006).

These profitability indicators were calibrated on the basis of a PFC Energy study (2006a). This study is an analysis of 60 competing oil and gas projects around the world requiring capital investment of more than one billion dollars.

For each indicator, the projects were ranked in terms of profitability from the lowest to the highest. The results for the 12th-ranked project were considered "target" values. This means that 12 of the 60 projects analyzed would have a profitability that is lower than or equal to the target value, while 48 projects would have a higher profitability for this indicator. It should be noted that some projects have a low NPV but high IRR and vice versa. In other words, the 12th-ranked project is not the same project for all seven profitability indicators. This means that if the Alaska gas project is equal or lower than the target value it belongs with respect to this profitability indicator to the 20 percent worst projects in the world.

The following graph (Figure 29) prepared by PFC Energy illustrates how the IRR of three Alaska fiscal concepts of the Alaska gas project compare with the 60 projects for a range of prices. The green blocks represent the 2005 fiscal terms. It can be seen how the IRR of the Alaska gas project when plotted on the rate of return of the 60 competing projects is always well above the 80 percent line.

Figure 29. IRR of Three Alaska Fiscal Concepts Relative to Other Projects with $1 Billion Capital Expenditures, Under Various Price Conditions



Source: PFC Energy, 2006

This means that under the 2005 fiscal terms, the Alaska gas project would be among the 20 percent of the projects with the worst IRR. The blue dots represent the IRR of the Alaska gas project under the contract. It can be seen how these blue dots are significantly below the green squares. This means that the IRR is better than the 2005 fiscal terms. The blue dots are typically between the 70 and 80 percent lines. Under the proposed contract, 70 percent of the projects would have a higher IRR than the Alaska gas project, but 20 percent would have a lower IRR. This means the probability the Alaska gas project would go forward is significantly improved.

Given, the fact that the NPV10 and NCF values depend on the size of the project, these values were determined using the NPV10/BOE and NCF/BOE values.

The target values were determined for a range of gas prices (Chicago city gate), as shown in Table 20.

Table 20. Target Values for Profitability for Different Gas Price Levels at Chicago City Gate (2006$)

Price ($/mmBtu)	IRR (%)	NPV10 ($ Millions)	PFR10 ($/$)	NCF ($ Billions)	NPV/ BOE ($/BOE)	NPV/ Capex ($/$)	NCF/ BOE ($/BOE)
2.50	10.0	-735	0.96	10.0	-0.10	-0.08	1.5
3.50	13.0	2,500	1.15	22.0	0.33	0.12	3.0
4.50	16.5	4,500	1.33	32.0	0.60	0.24	4.4
5.50	19.5	6,500	1.50	40.4	0.87	0.32	5.5
6.50	22.0	8,500	1.65	44.2	1.15	0.39	6.0
7.50	24.0	10,500	1.77	46.0	1.40	0.45	6.3
8.50	25.0	12,300	1.87	47.8	1.65	0.52	6.5

Source: PVM Model

Note: The model uses a 38-year horizon, with 8 years of planning, procurement, and construction, and 30 years of production.

A profitability indicator below the target value is considered "unattractive." For the purpose of determining the competitiveness, the Alaska gas project is considered "unattractive" when many of the indicators are below the target values or when some of the indicators are substantially below these target values.

Whether a project such as the Alaska gas project is "competitive" or not depends on more than just these profitability indicators. The competitiveness of a project is determined by the overall risk-reward balance and other strategic considerations.

The main risk factors are economic, fiscal, resource, political and regulatory, environmental, and financial. The Alaska gas project must be considered high risk in terms of cost overrun risk and fiscal risk. These risks will be discussed in more depth below.

Strategic considerations also play a role in determining the competitiveness of a project. Main strategic considerations include:

- The amount of reserves that can be booked;
- The degree to which the project provides a strategic position to develop or enhance other related business and investment opportunities; and
- The significant long-term stable net cash flow.

It should be noted that the Alaska gas project scores very positively with respect to both of these strategic aspects.

Based on a simple six mcf per barrel conversion, a 30-year production project would involve the possibility to book about 6,400 million barrels equivalent of oil by the various producers participating in the project. This project would result in the single largest increase in "bookable reserves" in the world.[61]

[61] Bookable reserves are known reserves that pass standards of the U.S. Securities and Exchange Commission (SEC) and can be included on the balance sheets of oil and gas companies, thus increasing their asset base and the value of the company. The 35 tcf of known gas reserves on the ANS do not currently pass the SEC standards because there is no means to transport the gas to market.

The Alaska gas project also has immense strategic value for the sponsors with respect to related business and investment opportunities. The project would create a strong strategic position for sponsors to use their acreage position on the North Slope to discover and develop more oil and gas in a profitable manner. The project also provides an excellent opportunity to enhance existing gas marketing operations.

Comparison with 2005 Fiscal Terms

The 2005 fiscal terms for ANS gas are largely the terms which have been applied so far to oil.

It should be noted that internationally, many jurisdictions with stranded gas and relatively low wellhead prices have opted to develop fiscal terms which are more attractive to the investors for gas. The government take for gas is less than for oil. ANS gas is clearly gas with a low net back.

It was for this reason that the SGDA was developed. It was realized that ANS gas could not be developed under a fiscal system that is identical to the one for oil. Therefore, the government was given permission to negotiate special contracts for approval by the legislature.

It is highly questionable whether the 2005 fiscal terms applied to gas result in a viable and competitive fiscal system. From an economic perspective, this makes the 2005 fiscal terms an inappropriate benchmark for comparison. Nevertheless, the 2005 fiscal terms are well known to the legislature. Therefore, because these terms serve as an important reference point, this section provides comparisons between the proposed contract and the 2005 fiscal terms. During the negotiations, the 2005 fiscal terms also served as a reference point. An objective during the negotiations was to improve the economics of the project significantly without substantially lowering the total Alaska income relative to the 2005 fiscal terms.

5.1.3 Large Size of Alaska Project

The Alaska gas project is a highly unique and unusual project from an economic perspective. Under current Chicago city gate gas prices, the undiscounted net cash flow ("NCF") of the project to the producers is the largest in the world. At $6.50 per mmBtu (Chicago city gate), a project terminating in Alberta would generate a total net cash flow of $121.6 billion (in constant 2006 dollars) to the producers under the 2005 fiscal terms. This is a substantial amount of cash (the PVM model assumes only a 38-year cash flow from the effective date of the contract, eight years prior to the commencement of operations, and 30 years production). Even at a low price of $3.50 per mmBtu (or $22 per barrel WTI) the net cash flow would still be $50.7 billion. This would still be one of the highest net cash flows in the world.

The huge cash flow is due to the enormous size of the project. However, it is also the result of the relatively low operating costs of the project. Most of the gas will be derived from Prudhoe Bay where incremental gas production costs will be minimal. The operating costs of the midstream are low. The combined operating costs for the upstream and midstream portions of the project are only $0.34 per mmBtu.

The NPV10 of the project is huge under current gas prices of $6.50 per mmBtu. Under 2005 fiscal terms, the NPV10 would be $12.7 billion in real 2006 dollars. This is among the highest NPV10 values in the world for a single project.

At the same time, however, the Alaska gas project requires the second largest capital expenditure in the world for a single project. Contrary to other projects, more than 95 percent of these expenditures occur prior to the first revenues.

5.1.4 Need for a Stranded Gas Contract

Given these economics, why is the Alaska gas project not going forward on the basis of the current fiscal terms on a normal commercial basis? Why do we need a stranded gas contract?

The last three decades have demonstrated that oil and gas prices are highly variable and notoriously difficult to predict. In the late 1970s, an energy crisis was predicted with oil prices going up to very high levels, then prices crashed in the mid-1980s. Only three years ago, the average long-term oil price forecast was $25 per barrel, but some analysts predict a long-term price of $60 per barrel. There is a significant possibility that oil and gas prices may be substantially lower again at some time in the future.

Therefore, a very large project with a very long lead time, requiring $21 billion or more, needs to be evaluated on the basis of a variety of possible scenarios of gas prices and costs, with a special emphasis on the stress price.

Table 21 compares the 2005 fiscal terms with the proposed contract terms for four important profitability indicators. The values in “bold” illustrate the values that do not meet the target values discussed above.

Table 21. Targets Values and Alaska Gas Project

		2005 Fiscal Terms		Proposed Contract Terms	
Indicator	**Target**	**Alberta**	**Chicago**	**Alberta**	**Chicago**
IRR (%)	13.0	**11.8**	**10.5**	14.0	**12.2**
NPV10 ($ million)	2,500	**1,685**	**664**	3,098	2,520
NCF ($ billion)	22.0	50.8	62.5	50.7	61.0
NPV10/BOE ($/BOE)	0.33	**0.23**	**0.09**	0.42	0.34

Source: PVM Model

Note:

1. The model uses a 38-year horizon, with 8 years of planning, procurement, and construction, and 30 years of production.
2. Dollar values are expressed in constant (real) 2006 dollars.
3. Assumes natural gas price of $3.50 per mmBtu (Chicago city gate).

The table illustrates that the Alaska gas project would be unattractive under the 2005 fiscal terms, regardless of whether the project ends in Alberta or Chicago. The Chicago project falls short of target values on three of the profitability indicators. It is therefore unlikely that investors would go forward with this project under 2005 fiscal terms. Under the proposed contract, all target levels are met or exceeded, except for the IRR with respect to the Chicago market, which remains slightly under the target value. A stranded gas contract is required in order to enhance the probability that the Alaska gas project will be realized.

It is clear that the proposed contract achieves the objective of making the Alaska gas project more competitive, as stated in Section 43.82.210 (b)(1) of the SGDA. The proposed contract achieves this objective as a direct result of the risk sharing and participation by the State of Alaska, as will be explained more fully below.

5.1.5 Effect of Cost Overruns

Table 22 shows the real IRR with cost sensitivity between 90 and 150 percent of the capital and operating expenditures. These real IRR values should be compared to the target IRR of 13 percent. Even at 90 percent of the costs, the table shows that the 2005 fiscal terms would not result in an attractive project based on the IRR profitability indicator

Table 22. Real IRR of the Alaska Gas Project with Cost Sensitivity

	2005 Fiscal Terms		Proposed Contract Terms	
	Alberta	Chicago	Alberta	Chicago
Sensitivity (Percent)	Percent			
90	12.8	11.5	15.1	13.4
100	11.8	10.5	14.0	12.2
110	10.9	9.6	13.0	11.3
120	10.2	8.9	12.1	10.4
130	9.5	8.3	11.3	9.6
140	8.9	7.7	10.6	8.9
150	8.3	7.1	10.0	8.3

Source: PVM Model.

Note: Assumes natural gas price of $3.50 per mmBtu (Chicago city gate).

Table 23 shows the results for the same cost variation for the NPV10/BOE. The values in the table should be compared with a target of $0.33 per barrel equivalent.

Table 23. Real NPV10/BOE of the Alaska Gas Project and with Cost Sensitivity

	2005 Fiscal Terms		Proposed Contract Terms	
	Alberta	Chicago	Alberta	Chicago
Sensitivity (Percent)	$/BOE			
90	0.33	0.25	0.51	0.48
100	0.23	0.09	0.42	0.34
110	0.13	-0.07	0.34	0.21
120	0.02	-0.23	0.25	0.07
130	-0.08	-0.39	0.17	-0.07
140	-0.18	-0.55	0.08	-0.20
150	-0.29	-0.71	-0.01	-0.34

Source: PVM Model.

Note: Assumes natural gas price of $3.50 per mmBtu (Chicago city gate).

Under the proposed contract, the target values are reached for the Alberta market up to a cost level of 110 percent of the assumed costs. For the Chicago market, it would have to be 90 percent of the assumed costs for the IRR and 100 percent of the cost for the NPV10/BOE.

Cost overruns of 20 percent are not unusual. Based on such a cost overrun, the Alaska gas project is unattractive under both the 2005 fiscal terms and the proposed contract terms.

Cost overruns of 50 percent are not improbable. In fact, high cost overruns are quite common for very large projects. With a 50 percent cost overrun and a stress price of $3.50 per mmBtu, the Alaska gas project would provide dismal results. Under these conditions, the Alaska gas project would be considered by the sponsors to be overcapitalized and undervalued. The project would not only be uncompetitive relative to other projects, but highly uneconomic in an absolute sense. It is clear that this constitutes a serious risk to investors.

It is obvious that under conditions of a stress price and cost overruns in the 20 to 50 percent range, the investors will be faced with a highly unprofitable project compared to other projects in the world. Under these conditions, the sponsors will not be adequately compensated for risk and the objective as indicated by Section 43.82.210 (b)(5) of the SGDA will not be achieved.

It is important to review the total Alaska revenues under the same conditions. Table 24 illustrates the real undiscounted total Alaska revenues in millions of dollars under the same stress price and with cost sensitivity.

Table 24. Real Total Alaska Revenues under the Alaska Gas Project with Cost Sensitivity

	2005 Fiscal Terms		Proposed Contract	
	Alberta	Chicago	Alberta	Chicago
Sensitivity (Percent)	$ Millions			
90	24,865	27,513	23,936	28,107
100	24,250	26,302	23,337	27,085
110	23,635	25,091	22,738	26,062
120	23,020	23,880	22,138	25,040
130	22,405	22,668	21,539	24,018
140	21,790	21,457	20,940	22,996
150	21,175	20,246	20,340	21,973

Source: PVM Model

Notes:

1. The model uses a 38-year horizon, with 8 years of planning, procurement, and construction, and 30 years of production.
2. Dollar values are expressed in constant (real) 2006 dollars.
3. Assumes natural gas price of $3.50 per mmBtu (Chicago city gate).

The following table (Table 25) shows the real total Alaska take (the values are expressed as percentages).

Table 25. Real Total Alaska Take under the Alaska Gas Project and with Cost Sensitivity (%)

	2005 Fiscal Terms		Proposed Contract	
	Alberta	Chicago	Alberta	Chicago
Sensitivity (Percent)	Percent			
90	23.3	20.9	22.5	21.5
100	23.2	20.5	22.4	21.2
110	23.1	20.1	22.3	21.0
120	23.0	19.7	22.2	20.7
130	22.9	19.2	22.0	20.4
140	22.7	18.7	21.9	20.1
150	22.6	18.2	21.8	19.8

Source: PVM Model

Note: Assumes natural gas price of $3.50 per mmBtu (Chicago city gate).

A number of important observations can be made. Despite the dismal economics to the investors under the stress price and significant cost overruns, the total Alaska revenues remains very significant both in terms of total real dollars and Alaska take.

Section 43.82.210 (b)(6) of the SGDA requires the commissioner to ensure a significant share of the economic rent for the state and the affected municipalities under favorable price and cost conditions. It was contemplated in the SGDA that, under unfavorable price and cost conditions, the state may have to lower its share of the economic rent significantly.

In fact, under the proposed contract, the share of economic rent and total revenues to the state and affected municipalities remains very substantial even under highly unfavorable price and cost conditions. The objectives of Section 43.82.210 (b)(6) of the SGDA are certainly achieved under these conditions.

It is also clear that under unfavorable price and cost conditions, the interests of the state and affected municipalities are accommodated to a high degree. Therefore, with respect to Section 43.82.210 (b)(2) of the SGDA, the proposed contract balances the interests very much in favor of the state and affected municipalities under unfavorable price and cost conditions.

As will be discussed below, the overall balance of the proposed contract for the investors is restored when average and higher prices are also taken into account. The unattractiveness of the IRR, NPV10, and NPV10/BOE are also counterbalanced by a highly attractive stable long-term net cash flow.

This, however, makes fiscal certainty essential. Investors have to be able to count on the net cash flow in order to pull the project through under possible downside conditions in terms of low prices and cost overruns.

It is crucial to avoid high cost overruns in the first place. This can be done with detailed and careful planning in the first few years of the project. The work commitments of the proposed contract are structured in a manner that this can be achieved.

An important observation that can be made from the Alaska take table above is that under higher costs, the Alaska take decreases. The reason for the decrease is that under higher cost conditions, the cash flow of the midstream segment becomes more important relative to the upstream segment.

Since the upstream segment is subject to a much higher Alaska take than the midstream segment, the overall Alaska take declines with higher costs, both under the 2005 fiscal terms and the proposed contract. The important PPT credit on the GTP and lateral lines also automatically increases with higher costs.

Therefore, the proposed contract modestly achieves the objective of Section 43.82.210 (b)(3) of the SGDA, which prescribes that the proposed contract should be progressive in the sense that the combined share of the economic rent that the state and affected municipalities achieve should be higher when costs are less.

5.1.6 Combined Share of the Economic Rent

From a fiscal perspective, the main benefit for Alaska of the proposed contract is the substantial new Alaska revenues for the state and municipal governments from this project. Table 26 shows total Alaska revenues (State of Alaska and affected municipalities) under the 2005 fiscal terms and proposed contract terms for both the Alberta and Chicago projects (values are in constant 2006 dollars). The total revenues under the proposed contract include the return on state's investment in the pipeline.

Table 26. Real Total Alaska Revenues under the Alaska Gas Project at Different Gas Prices

	2005 Fiscal Terms		Proposed Contract	
	Alberta	Chicago	Alberta	Chicago
Price	$Millions			
$2.50	13,433	15,472	12,501	16,247
$3.50	24,250	26,302	23,337	27,085
$4.50	35,307	37,390	34,402	38,180
$5.50	46,213	48,300	45,315	49,098
$6.50	57,192	59,289	56,302	60,094
$7.50	68,153	70,255	67,271	71,068
$8.50	79,064	81,166	78,189	81,986

Source: PVM Model

Note:

1. The model uses a 38-year horizon, with 8 years of planning, procurement, and construction, and 30 years of production.
2. Dollar values are expressed in millions of constant (real) 2006 dollars.
3. Natural gas price are in dollars per mmBtu (Chicago city gate).

The tables are presented on a before financing basis. This is because major oil companies typically compare international projects on a before financing basis. The reason that major oil companies evaluate projects in this way is that financing typically does not take place on a project financing basis, but instead against the general balance sheet of the company. The competitiveness of a project is determined before financing in order to ensure that the company selects the best combination of projects. Financing is then done at the corporate level, not the project level.

However, the cost of interest payments on debt in real terms is about $1 billion on the Alberta project and $1.5 billion on the Chicago project. On an after financing basis, these costs need to be deducted from the total Alaska revenues under the proposed contract.

The differences between the 2005 fiscal terms and the proposed contract are:

- The state gains revenues on its investments in the midstream and the midstream municipalities gain some revenues as a result of the change of the property tax to a cents/mmBtu basis.
- The state loses marketing costs of the gas, the upstream cost allowance, and the state share of property taxes outside municipal boundaries along the pipeline right-of-way and provides the 35 percent PPT credits on the GTP and lateral lines.

Table 27 shows these differences in much more detail for an Alaska gas project ending in Alberta and $5.50 per mmBtu price scenario.

Table 27. Difference Between 2005 Fiscal Terms and Proposed Contract Terms, Alberta Project

Category	2005 Fiscal Terms	Proposed Contract Terms
Royalties	$23,192	
Severance Tax	$11,137	
State Gas	$34,329	$34,685
Market Costs		-$488
UCA		-$1,842
Net State Gas	$34,329	$32,355
NPS	$790	$790
Net Cash Flow	$0	$2,922
North Slope Property Tax (Municipalities)	$1,763	$1,362
Midstream Property Tax (Municipalities)	$502	$1,202
North Slope Property Tax (State)	$61	$0
Midstream Property Tax (State)	$1,191	$0
Total Property Tax	$3,517	$2,564
State Corporate Income Tax - Upstream	$6,573	$6,732
State Corporate Income Tax - Midstream	$1,004	$740
GTP/Feeder Line Credit	$0	-$788
Total	$46,213	$45,315

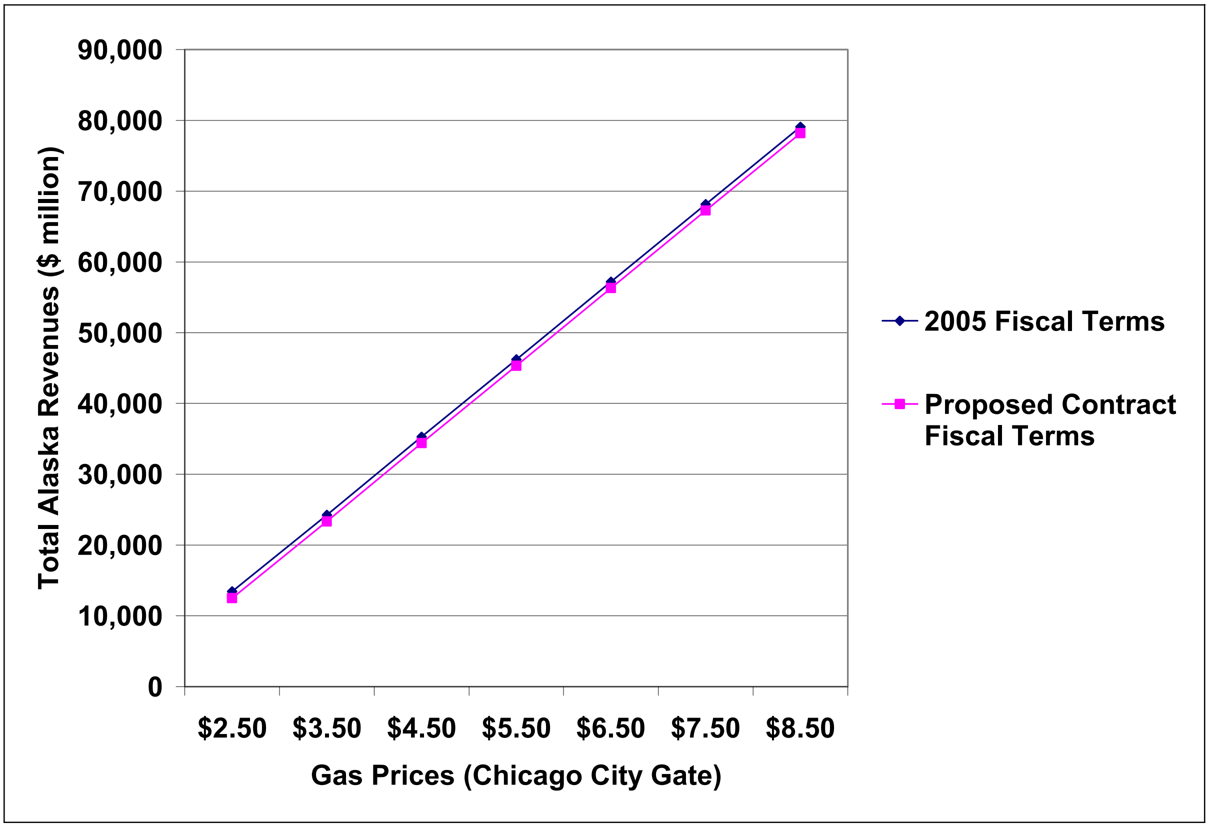
Source: PVM Model

Notes:

1. The model uses a 38-year horizon, with 8 years of planning, procurement, and construction, and 30 years of production.
2. Assumes natural gas prices of $5.50 per mmBtu (Chicago city gate).
3. Values are expressed in millions of real 2006 dollars.

As the tables and the figure (see Figure 30) indicate, the end result is that for every price level there are only minor differences in total Alaska revenues between the 2005 fiscal terms and the proposed contract terms.

Figure 30. Real Total Alaska Revenues under Different Price Levels for the Alberta Project (Before Financing)



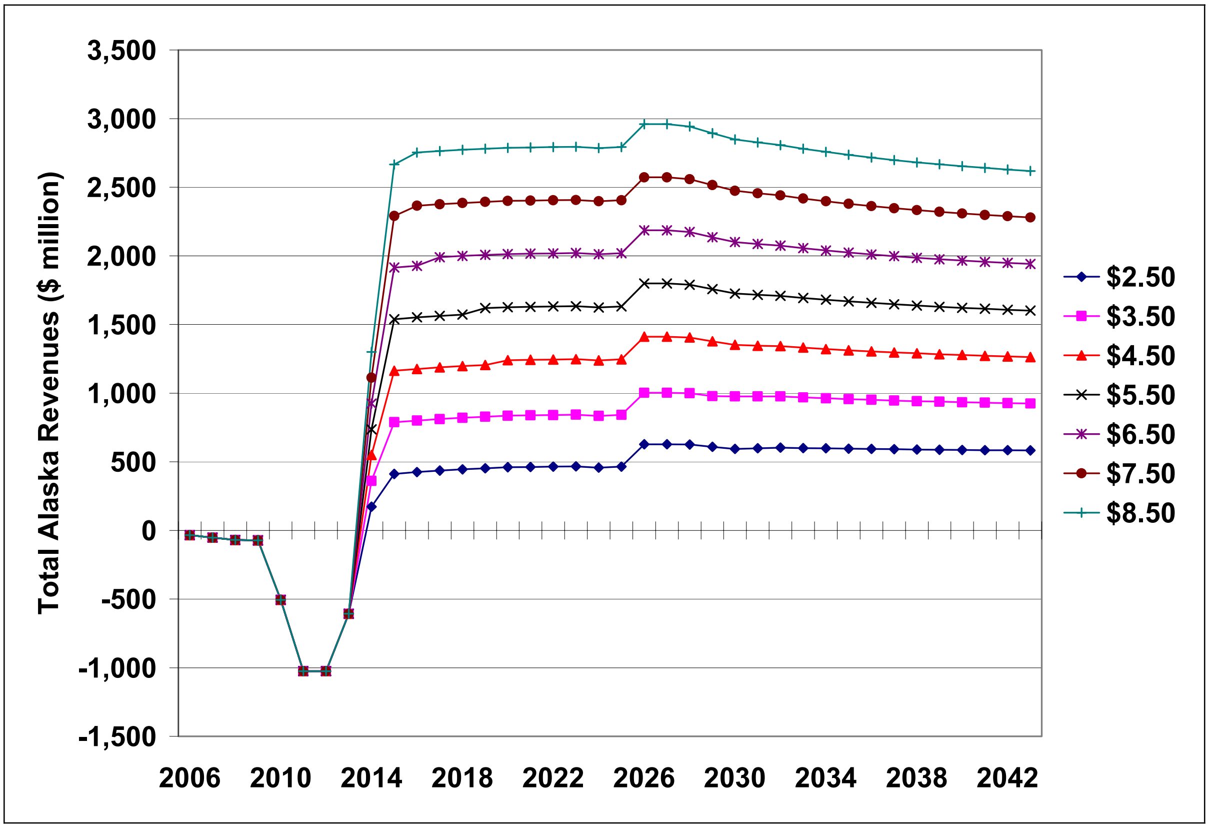
Source: PVM Model.

Notes:

1. The model uses a 38-year horizon, with 8 years of planning, procurement, and construction, and 30 years of production.
2. Dollar values are expressed in millions of constant (real) 2006 dollars.
3. Natural gas price are in dollars per mmBtu (Chicago city gate).

Figure 31 shows the total Alaska revenues under the proposed contract on an annual basis.

Figure 31. Real Total Alaska Revenues under the Proposed Contract Terms for the Alberta Project



Source: PVM Model

Notes:

1. The model uses a 38-year horizon, with 8 years of planning, procurement, and construction, and 30 years of production.
2. Dollar values are expressed in millions of constant (real) 2006 dollars.
3. Natural gas price are in dollars per mmBtu (Chicago city gate).

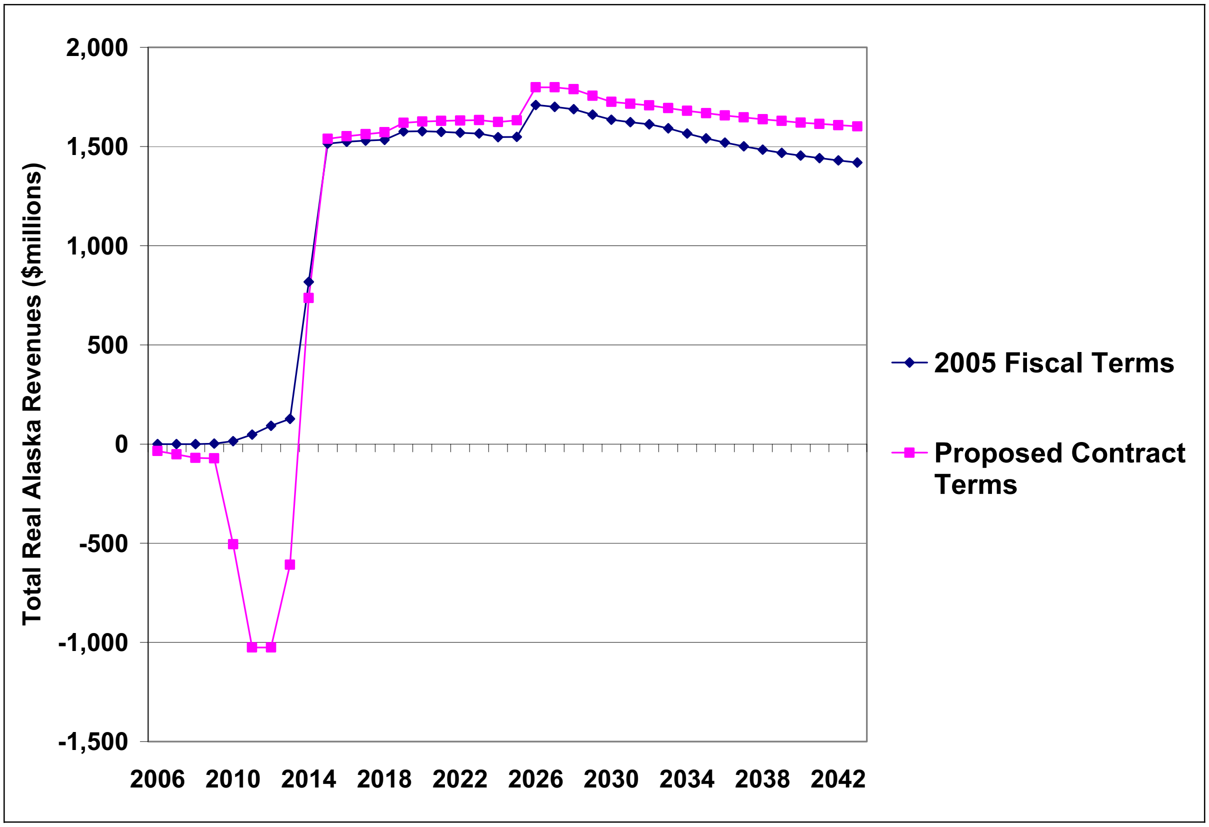
Even at a price of only $2.50 per mmBtu (in constant 2006 dollars), the State of Alaska will still gain considerable revenues in real terms.

The estimated Alaska revenues per year (in real 2006 dollars) under different gas prices (Chicago city gate) are as follows:

- At low prices of $3.50 per mmBtu: about $1 billion per year;
- At average prices of $5.50 per mmBtu : about $1.7 billion per year; and
- At high prices of $8.50 per mmBtu: about $2.7 billion per year.

The following chart (Figure 32) shows the year by year total Alaska revenues for $5.50 per mmBtu for the 2005 fiscal terms and the proposed contract. The difference with the 2005 fiscal terms is that during the construction period the state will co-invest in the construction of the midstream. During the subsequent years, the state receives slightly higher revenues than would otherwise be the case under the 2005 fiscal terms. This difference grows over time.

Figure 32. Real Total Alaska Revenues, 2005 Fiscal Terms and Proposed Contract Fiscal Terms



Source: PVM Model

Notes:

1. Revenues are expressed in millions of constant (real) 2006 dollars from 2006 to 2043.
2. Assumes a natural gas price of $5.50 per mmBtu (Chicago city gate).

The proposed contract provides a very significant shift of the combined share of the economic rent from the early years, through the negative cash flow, to the later years with a higher positive cash flow.

It should be noted that the strong negative cash flow is on a before financing basis. As will be explained in Section 7 of this report, it is intended that 80 percent of these investments by the state will be debt financed. Therefore, the actual negative cash flow will be much less, but as explained above, the positive cash flow also has to be reduced by the interest payments on the debt.

In addition, some modest back end loading was achieved by making the property tax on a cents/mmBtu basis. This has the effect of leveling the cash flow to the municipalities relative to stronger revenues later in the operations.

The proposed contract achieves the objective of Section 43.82.210 (b)(4) of the SGDA, which prescribes that the proposed contract should be back end loaded.

Table 28 compares the Alaska take for the proposed contract with the 2005 fiscal terms.

Table 28. Total Real Alaska Take under the 2005 and the Proposed Fiscal Terms at Different Gas Prices

Gas Price ($/mmBtu)	2005 Fiscal Terms		Proposed Contract	
	Alberta	Chicago	Alberta	Chicago
	Percent			
2.50	23.6	19.3	22.1	20.3
3.50	23.2	20.5	22.4	21.2
4.50	23.2	21.3	22.6	21.8
5.50	23.1	21.6	22.7	22.0
6.50	23.1	21.9	22.8	22.2
7.50	23.1	22.0	22.8	22.3
8.50	23.1	22.2	22.8	22.4

Source: PVM Model

Note: Natural gas prices are expressed in $ per mmBtu at the Chicago city gate.

With respect to the Chicago project, both the 2005 fiscal terms and the proposed contract are progressive with price. With respect to the Alberta project, the 2005 fiscal terms are regressive, while the proposed contract is slightly progressive.

This is directly due to the important role of the midstream component of the project. The Alaska take on the midstream component is less than on the upstream component. Therefore, as the upstream revenues expand with higher prices, the Alaska take as part of the total divisible income is higher.

Therefore the proposed contract achieves in a modest way the objective of Section 43.82.210 (b)(3) of the SGDA, which prescribes that the proposed contract should be progressive with price.

Table 29 illustrates the three percent discounted real total Alaska revenues. The three percent discount rate is equal to a five percent discount rate on a nominal basis used in the PVM model, which assumes two percent escalation/inflation. This is the appropriate discount rate for state revenues.

Table 29. Total Real Alaska Revenues under the 2005 and the Proposed Contract Fiscal Terms at Different Gas Prices, 3 Percent Discount Rate

Price ($/mmBtu)	2005 Fiscal terms		Proposed Contract	
	Alberta	Chicago	Alberta	Chicago
	$ Millions			
$2.50	7,014	8,348	5,217	6,942
$3.50	12,782	14,125	10,963	12,689
$4.50	18,702	20,063	16,852	18,597
$5.50	24,539	25,903	22,658	24,406
$6.50	30,429	31,800	28,517	30,272
$7.50	36,308	37,683	34,366	36,124
$8.50	42,149	43,524	40,177	41,935

Source: PVM Model

1. The model uses a 38-year horizon, with 8 years of planning, procurement, and construction, and 30 years of production.
2. Dollar values are expressed in millions of constant (real) 2006 dollars; discounted at 3 percent.
3. Natural gas price are in dollars per mmBtu (Chicago city gate).

This table shows that the proposed contract is about $1.9 billion in discounted value below the 2005 fiscal terms for the average price of $5.50 per mmBtu. This is, of course, directly due to the state's risk sharing and participation, which creates a negative cash flow for the state early in the project.

The above table illustrates how Alaska on a discounted basis will receive very significant revenues at average and high prices.

Table 30 shows the three percent discounted Alaska take. This table illustrates how the 2005 fiscal terms create a regressive system on a discounted basis, but the proposed contract achieves clearly a progressive system. This illustrates that the objective of a progressive system is being achieved on a discounted basis as well.

Table 30. Real Total Alaska Take, 3 Percent Discounted under Different Chicago Gas Prices

Price ($/mmBtu)	2005 Fiscal terms		Proposed Contract Terms	
	Alberta	Chicago	Alberta	Chicago
	Percent			
$2.50	29.0	23.9	21.7	20.0
$3.50	25.9	23.5	22.3	21.2
$4.50	25.1	23.5	22.7	21.9
$5.50	24.6	23.5	22.8	22.2
$6.50	24.4	23.5	22.9	22.4
$7.50	24.2	23.5	23.0	22.5
$8.50	24.1	23.4	23.0	22.6

Source: PVM Model

It is important to note that the discounted Alaska take is very significant at favorable prices.

The proposed contract achieves fully the objective of Section 43.82.210 (b)(6) of the SGDA, which prescribes that the proposed contract should result in a significant share for the combined economic rent of the state and affected municipalities under favorable price and cost conditions.

5.1.7 Competitiveness of the Proposed Contract Terms

Despite the high revenues for the state, the question can be raised whether this is a competitive deal from an international perspective and whether more could be obtained for Alaska. Table 31 illustrates the total government take from the project. As explained earlier, this total government take includes the Alaska take as well as the federal U.S. and Canadian take and the take by Canadian provinces. At the average price forecast of $5.50 per mmBtu, the government take is about 51 percent.

Table 31. Total Government Take, Alberta Project

Price ($/mmBtu)	2005 Fiscal Terms	Proposed Contract Terms
	Percent	
2.50	52.4	53.1
3.50	51.4	51.8
4.50	51.2	51.4
5.50	51.0	51.0
6.50	50.9	50.9
7.50	50.8	50.8
8.50	50.8	50.8

Source: PVM Model

This is a very competitive government take compared to other long distance gas exporters aimed at the lower 48 market. Large volumes of stranded gas are currently being developed and marketed as LNG, and in some cases based on long distance pipelines. Other governments now typically have a government take for long distance export gas that is about ten percentage points less than for oil.

Table 32 and Figure 33 compare total government takes for the upstream only of various jurisdictions which export gas over long transport distances to the U.S. market. The comparison is based on a hypothetical six tcf dry gas field. Apart from the proposed contract, the chart also includes the general Alaska terms under the PPT for fields which are not subject to a stranded gas contract.

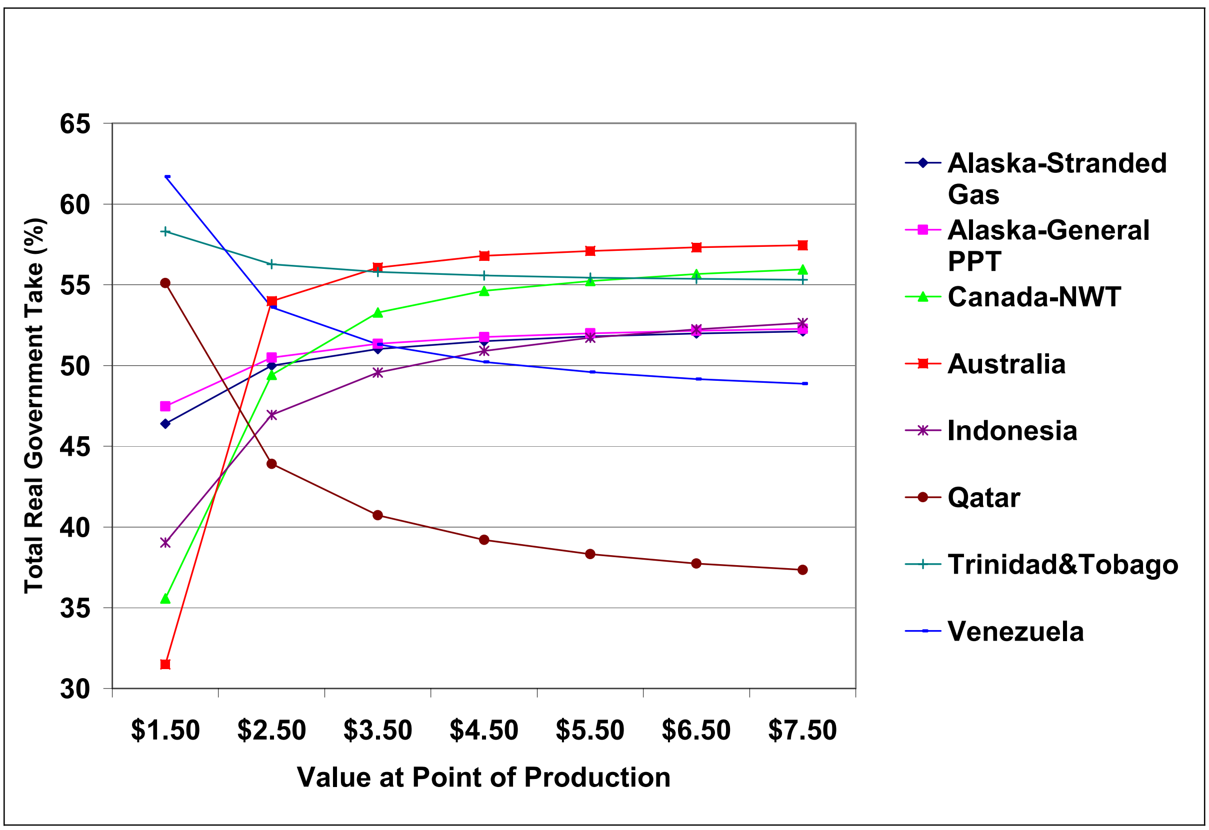
Table 32. Total Government Take at Different Wellhead Prices by Long Distance Gas Exporting Jurisdictions

Jurisdiction	$1.50	$2.50	$3.50	$4.50	$5.50	$6.50	$7.50
	Percent						
Alaska-Stranded Gas	46.39	49.99	51.02	51.51	51.80	51.98	52.12
Alaska-General PPT	47.48	50.49	51.35	51.76	52.00	52.15	52.27
Canada-NWT	35.58	49.42	53.29	54.62	55.24	55.66	55.95
Australia	31.49	53.99	56.07	56.79	57.10	57.31	57.45
Indonesia	39.04	46.94	49.57	50.91	51.72	52.25	52.64
Qatar	55.11	43.91	40.72	39.20	38.32	37.74	37.34
Trinidad & Tobago	58.30	56.28	55.79	55.58	55.45	55.37	55.31
Venezuela	61.70	53.61	51.31	50.22	49.59	49.17	48.88

Source: PVM Model

Note: Wellhead prices are expressed in dollars per mmBtu.

Figure 33. Total Government Take under Various Prices by Gas Exporting Jurisdiction



Source: PVM Model

The Alaska total government take is very competitive compared to a wide range of other jurisdictions. It can be seen how long distance gas exports typically target a government take in the 48 to 57 percent range. Alaska fits exactly in the middle of this range.

The fiscal systems of Canada (Mackenzie Delta), Indonesia, and Australia provide considerably lower government takes at low prices and are therefore more progressive than the Alaska system under low prices. Venezuela, Qatar, Trinidad, and Tobago have regressive systems.

The graph clearly illustrates that jurisdictions faced with long distance gas exports typically do not apply a strongly progressive systems. There is a significant difference between oil and gas in this respect. Governments with strongly progressive systems for oil, such as Trinidad, Tobago, and Qatar, have neutral or regressive systems for gas.

In all cases, gas exporting governments try to encourage investment by offering considerable upside under high prices. This compensates for the considerable downside price risk associated with high transport costs. It is also for this reason that Alaska is offering a modestly progressive system.

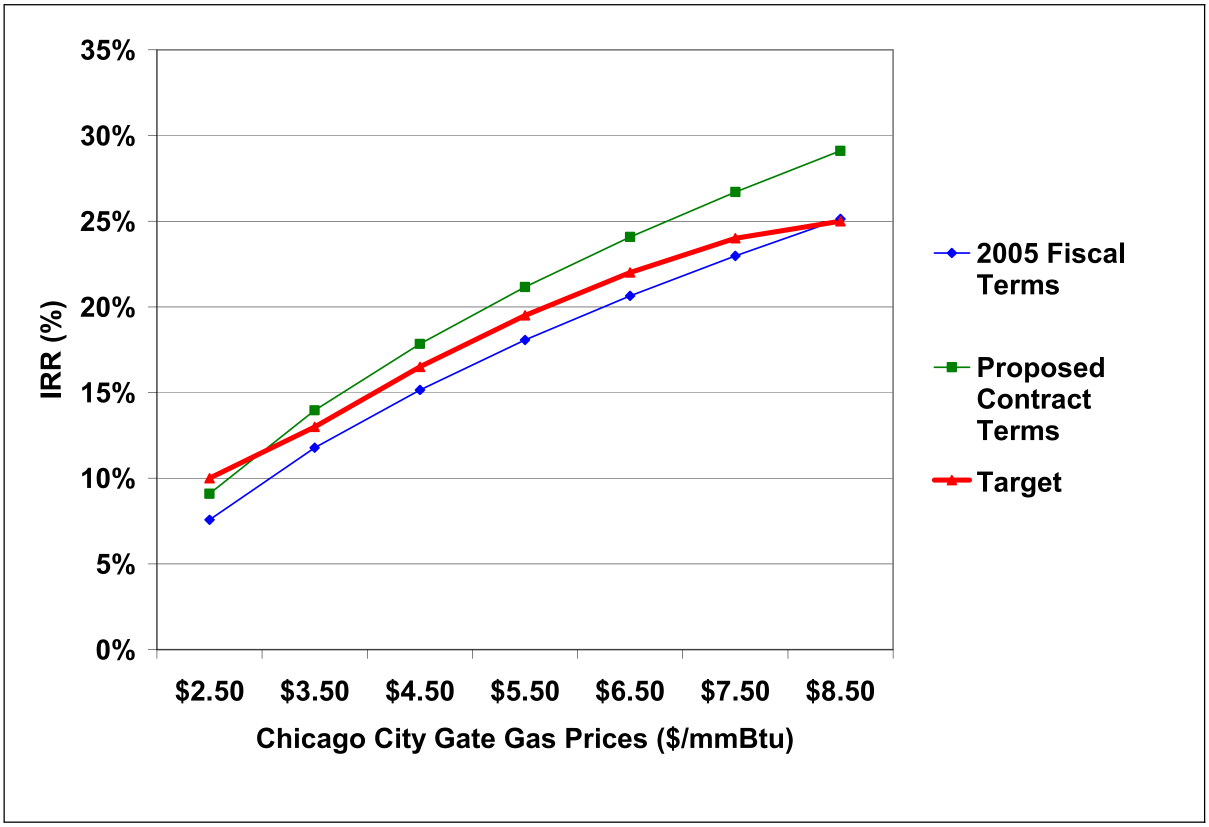
Qatar has a regressive system as a result of their unique feed gas price system for the upstream for delivery to LNG liquefaction.

It should be noted that none of the gas exporting jurisdictions have the favorable fiscal terms for the midstream that Alaska has, in particular, the attractive property taxes for municipalities.

5.1.8 Profitability for Investors under Favorable Prices

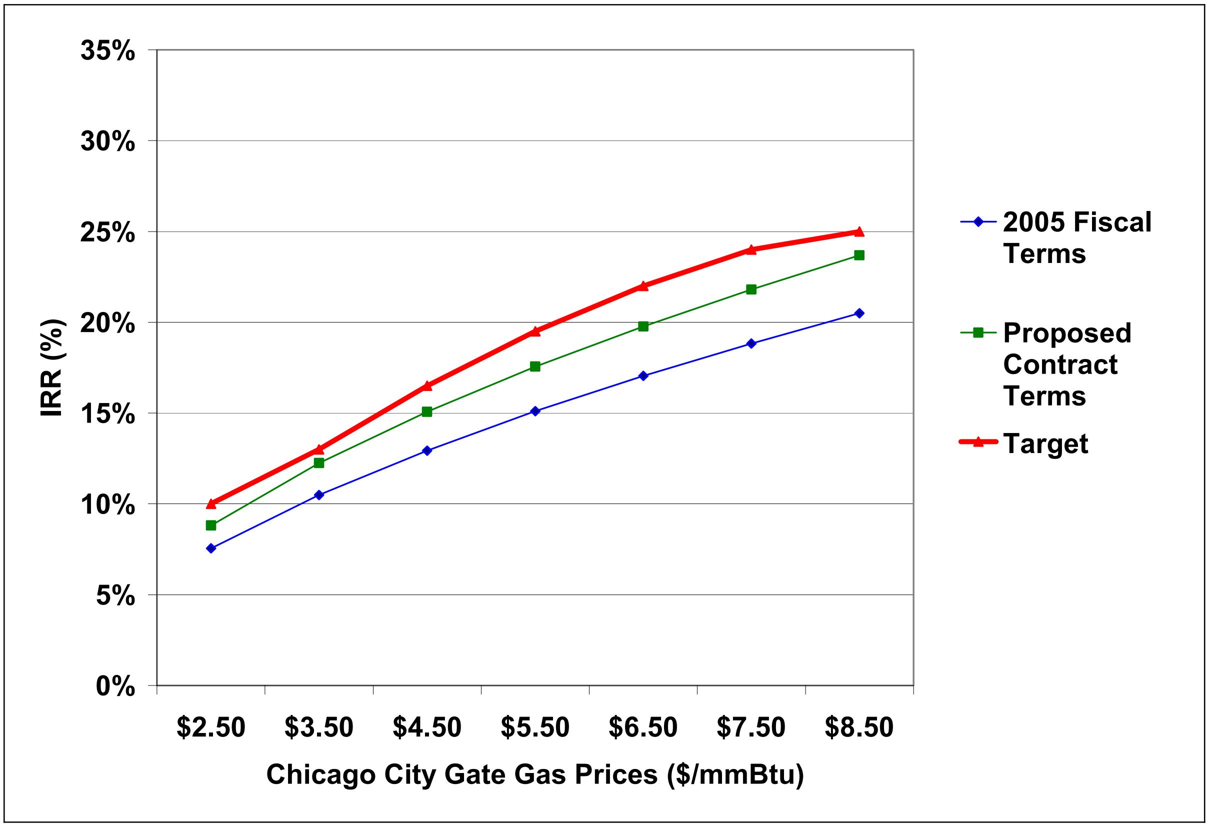
While it is necessary to improve the economics under low prices and cost overrun conditions, it is also important to evaluate the terms under high prices. Figure 34 and Figure 35 show the real IRR for the 2005 fiscal terms and the proposed contract for the Alberta and Chicago projects, respectively.

Figure 34. Real IRR for the Alberta Project



Source: PVM Model

Figure 35. Real IRR for the Chicago Project



Source: PVM Model

The 2005 fiscal terms would create a real IRR which is consistently below the competitive target for the Alberta project and, in particular, for the Chicago project.

In order to improve the competitiveness of the project to the point where there is a significant probability that the project goes forward, the stranded gas fiscal terms have to improve the real IRR substantially for every price level.

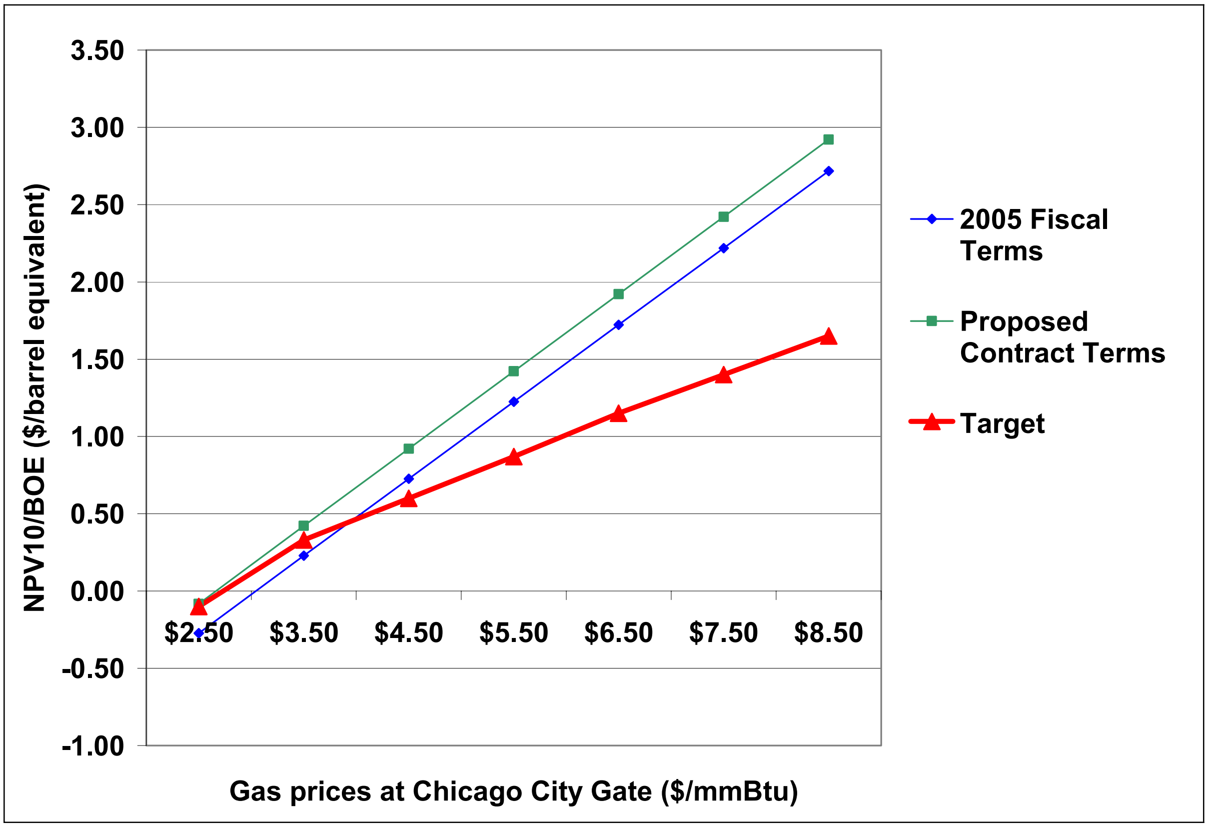
As can be seen from the two charts, the fiscal terms achieve this on average. The IRR which is slightly more favorable than the target values under the Alberta project is offset with an IRR that is slightly less favorable than the target values under the Chicago project.

The picture is different for other profitability indicators. A good indicator to compare the Alaska gas project with other projects is the NPV10/BOE. This illustrates the net value present of the project per barrel equivalent. This means the absolute size of the projects does not play a role in this comparison.

The two charts below indicate that the 2005 fiscal terms are unattractive under $4.50 per mmBtu, but over this price level the Alaska gas project becomes rapidly more attractive compared to other projects. In fact, over this price level, the 2005 fiscal terms would be adequate.

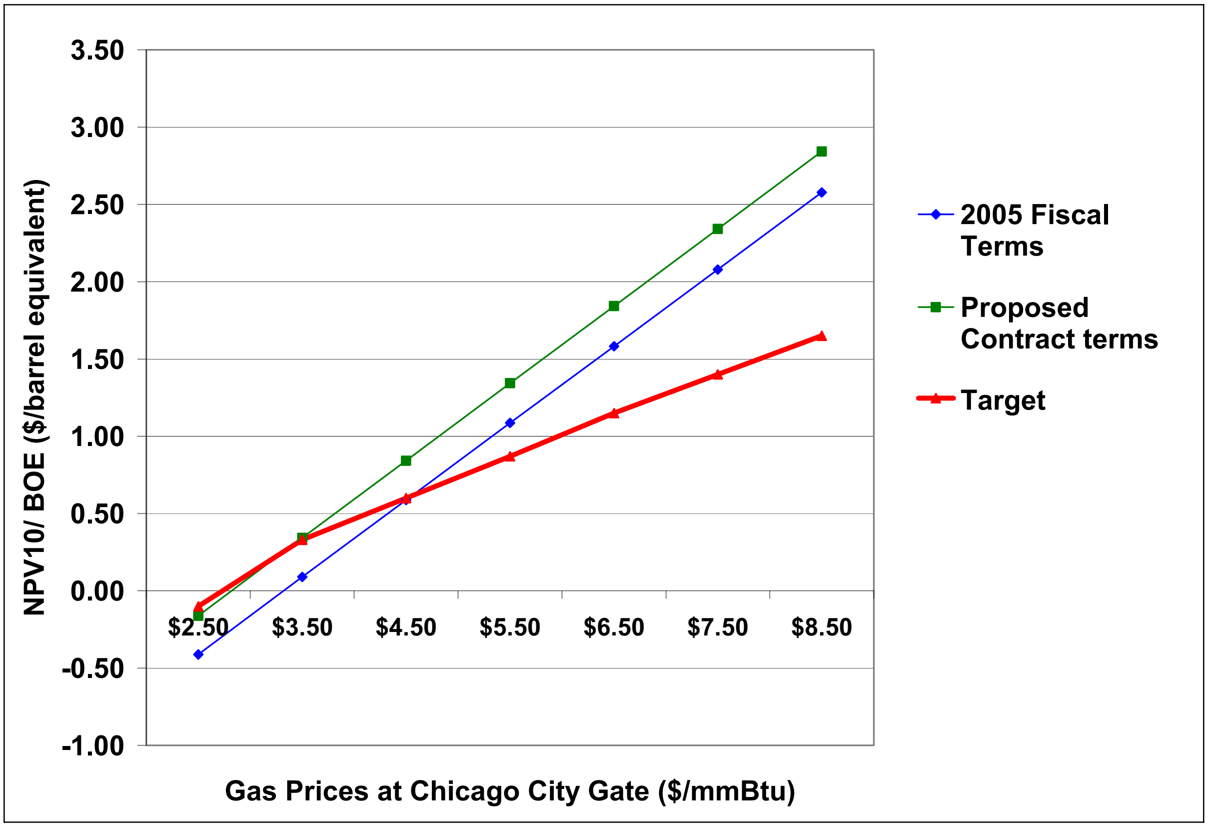
The reason for this behavior of this profitability indicator is that the price differential between the wellhead on the North Slope and Chicago is very high. This is mainly due to transportation costs. Under high prices, these transport costs remain constant and, therefore, higher prices rapidly add more value to the project on a relative basis.

Figure 36. Real NPV10/BOE for the Alberta Project



Source: PVM Model

Figure 37. Real NPV10/BOE for the Chicago Project



Source: PVM Model

There is a need to improve the NPV10/BOE below $4.50 per mmBtu, but not above this price level. An efficient way to improve the NPV10/BOE is to simply add a constant amount to this number. The amount should be high enough to create attractive economics under low prices but not so high that it would add unusual profitability to the high price scenarios.

With respect to the Alberta project, this amount under the proposed contract is $0.19 NPV10/BOE. It is the state risk sharing and participation and the related upstream cost allowance that creates this constant increase in NPV10/BOE.

An alternative would be to have lower production taxes or royalties. This would add a constant percentage to the values, which would create a low number at low prices and a high improvement at high prices. This is not efficient since it does not help very much under low price conditions and provides considerable profits under high price conditions.

The specific state risk sharing and participation proposal therefore improves the project enough under low prices to make the project attractive, without creating unnecessary increases in profits under high price scenarios.

It should be noted that the relatively attractive NPV10/BOE levels at high prices do not necessarily mean that the State of Alaska leaves “money on the table”. As the Risk Sharing and Participation Report discusses in more detail, even at $8.50 per mmBtu, the NPV10/BOE is still not at the median value of the 60 competitive projects used for comparative analysis.

Nevertheless, except for the IRR, all other six profitability indicators provide attractive values to the investor at favorable price and cost conditions.

The proposed contract achieves the objective of AS 43.82.210 (b)(5) of the SGDA, which prescribes that the proposed contract should compensate the investors for taking the project investment risks over a range of economic circumstances.

The relatively attractive profitability characteristics at favorable prices and costs balance for the investor the unattractive economics of the project under unfavorable prices and costs.

5.1.9 The Rationale for Risk Sharing and Participation by the State of Alaska.

It is clear from the analysis presented here that the IRR is the “Achilles heel” of the Alaska gas project. Without significant improvement in the real IRR, the project would be unattractive and vulnerable under the 2005 fiscal terms.

There are basically two ways in which the IRR can be significantly improved:

- Increase the profits to the investors by lowering the Alaska take; or
- Reduce the (net) investment required to be made by the investors in order to improve the ratio between profits and investment.

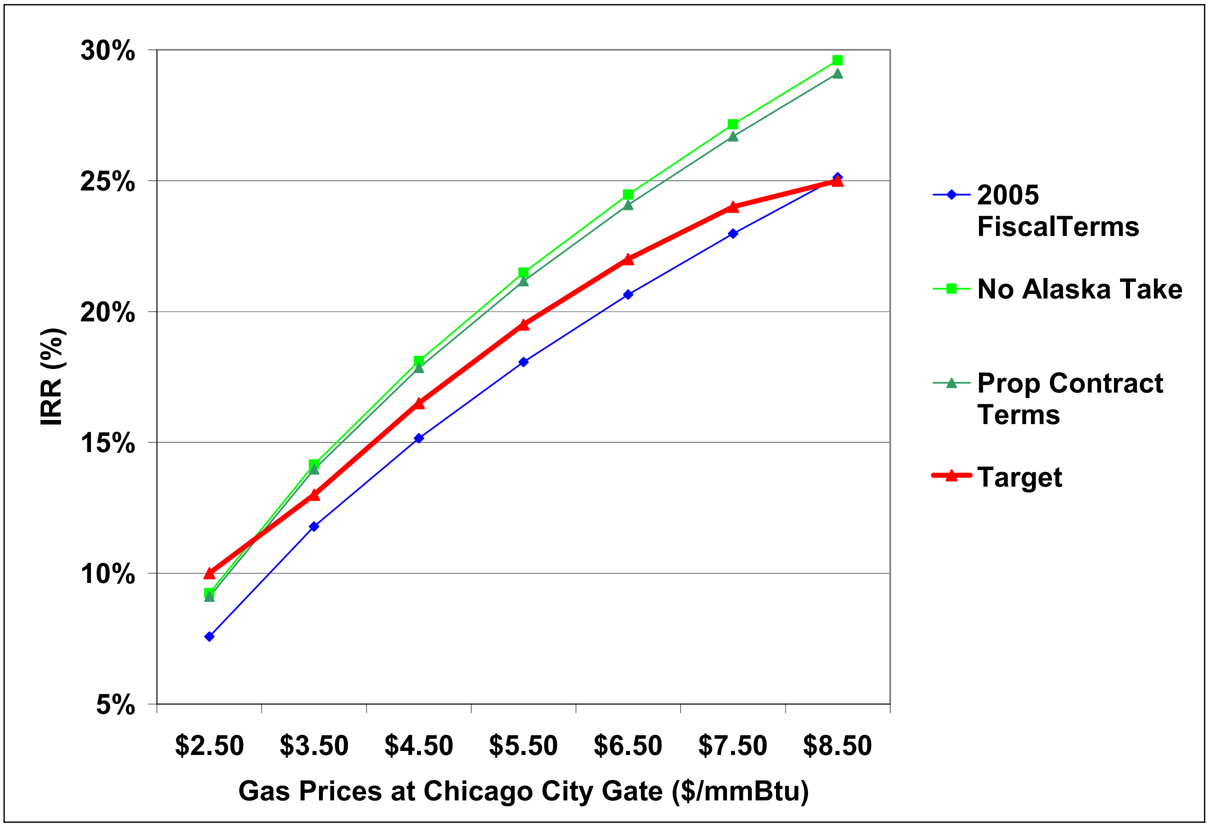
5.1.9.1 Reducing Alaska Take

A hypothetical case was evaluated under which the Alaska take was simply set at zero percent. This means the state does not collect any royalties, production taxes, property taxes, or state corporate income taxes.

Because the payments to the state are deductible for federal corporate income tax, the amount of U.S. federal corporate income tax goes up by $0.35 for every dollar less that is paid to the State of Alaska. Reducing the Alaska take to zero results in the overall government take going from about 51 percent to 36 percent. It is slightly above the U.S. federal rate of 35 percent, because Canada has higher total federal plus provincial corporate income tax rates and some Canadian property taxes would remain.

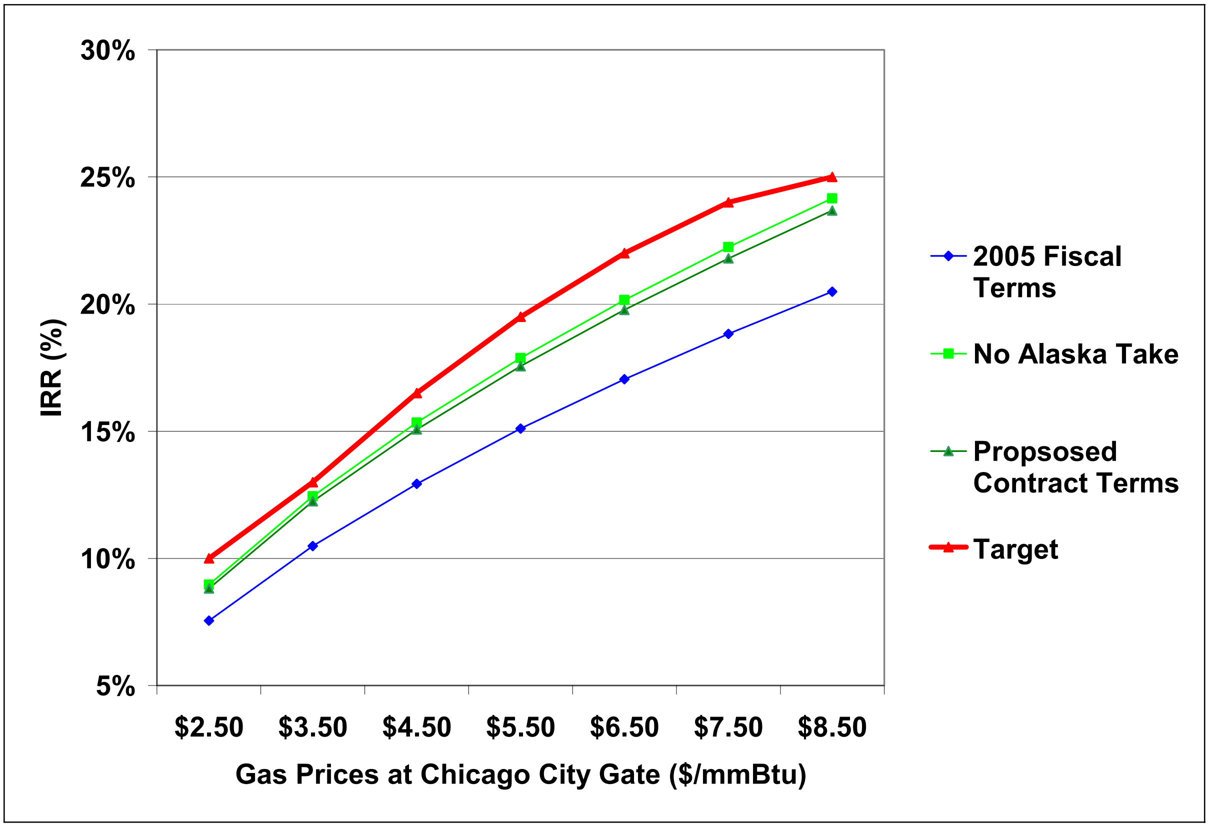
Figure 38 and Figure 39 show the effect of a “No Alaska Take” situation on the real IRR profitability indicator. As can be seen, the No Alaska Take line narrowly follows that of the proposed contract. In other words, in order to achieve the same IRR results as the proposed contract, one would have to set the Alaska take at zero. This is obviously an unacceptable option, but it clearly shows that reducing Alaska take is not an efficient way to improve the IRR.

Figure 38. Real IRR Evaluation of Zero Alaska Take for the Alberta Project



Source: PVM Model

Figure 39. Real IRR Evaluation of Zero Alaska Take for the Chicago Project



Source: PVM Model

5.1.9.2 Lowering Producer Investment

The state risk sharing will result in a situation where the state assumes full risk and responsibility for the shipping and marketing of the state gas, which is estimated to be initially somewhat less than 20 percent of the total gas. As a result of making shipping and marketing commitments for almost 20 percent of the gas, the midstream project of the GTP and gas pipelines can now be financed. The state will then participate for 20 percent in the project and benefit from the income earned as a result. However, this means that the sponsors and other producers are now only responsible for backing up 80 percent of the investment with shipping and marketing commitments.

Under this approach, the producer net revenues from the upstream project remain essentially the same. This creates a situation where the relationship between income and investment is favorably impacted.

The IRR result of the state risk sharing and participation is therefore identical to a No Alaska Take IRR. Therefore, the state risk sharing and participation is a significantly more effective way for the state to boost the IRR than reducing the Alaska take.

As was illustrated, even with this IRR improvement, the IRR remains modest over the entire gas price range.

5.1.9.3 Conclusion

The risk sharing and participation by the State of Alaska is the best option to accommodate the interests of the state, affected municipalities, and sponsors under a wide range of economic conditions and potential project structures, while achieving the objective of Section 43.82.210 (b)(2) of the SGDA.

5.1.10 The Need for Fiscal Certainty

The Alaska gas project will generate a very large net cash flow and NPV10 under average prices. Why do we need fiscal certainty under the stranded gas contract? Why not simply require investors to offset the downside risk with the considerable upside potential under the proposed contract?

The PPT process in the legislature has already demonstrated beyond any doubt that this legislature carefully analyzes a multitude of facts and opinions before making important decisions about petroleum fiscal matters. These decisions are being made in a balanced manner, with the various interests of all stakeholders and all available information taken into account.

Therefore, Alaska can certainly not be considered a jurisdiction with high fiscal risk.

Nevertheless, in the absence of a stranded gas contract, it is possible that legislative adjustments could be made that would erode much of the NPV10.

A hypothetical situation was evaluated whereby the proposed contract would have a re-opener at the start of commercial operations with respect to the amount of the tax gas rate. In other words, the 7.25 percent could be changed to any number on this date. In this hypothetical situation, it is also assumed that the new rate would be set unilaterally by the legislature.

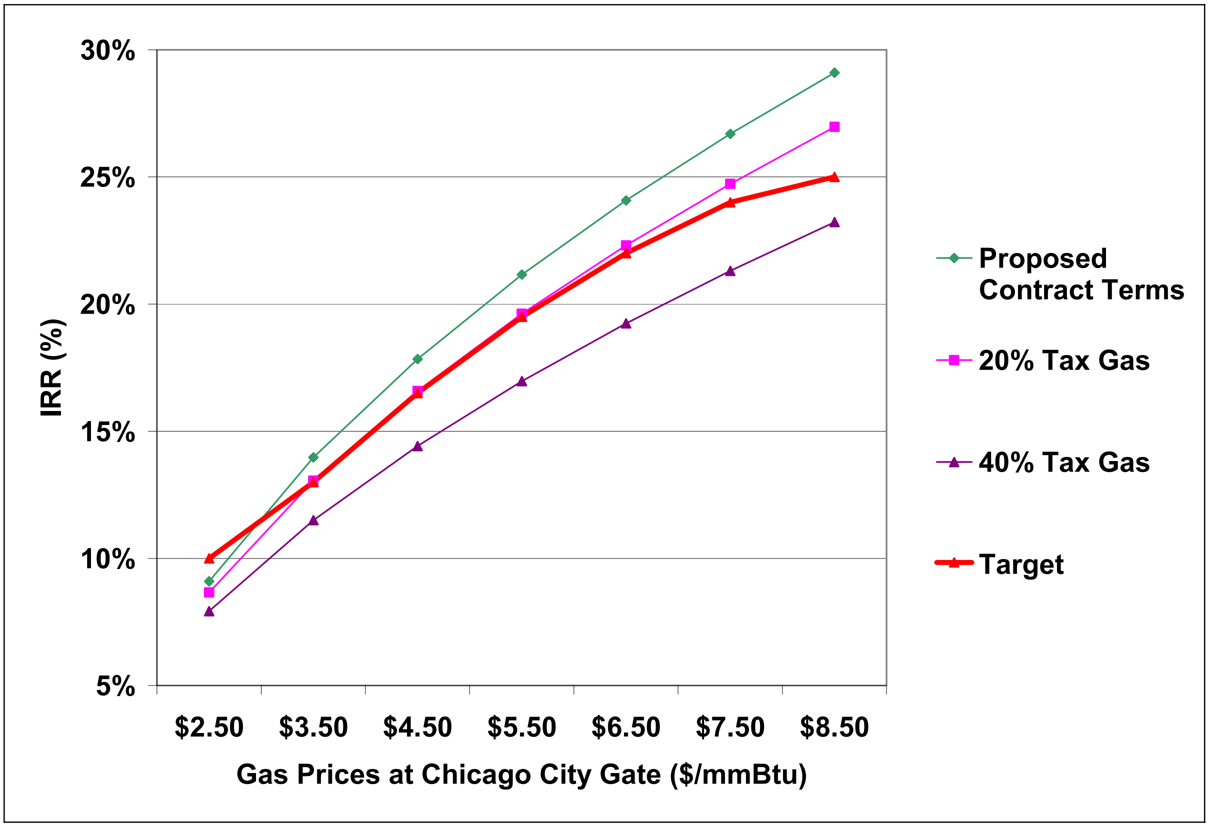
Two variations of the proposed contract were evaluated, consisting of a change to:

- 20 percent tax gas; and
- 40 percent tax gas.

If gas prices remain high during the next ten years, it is probable that the legislature may change the tax gas rate. The tax gas rate could, for instance, be changed to either 20 percent or 40 percent at the commencement of operations of the gas pipeline.

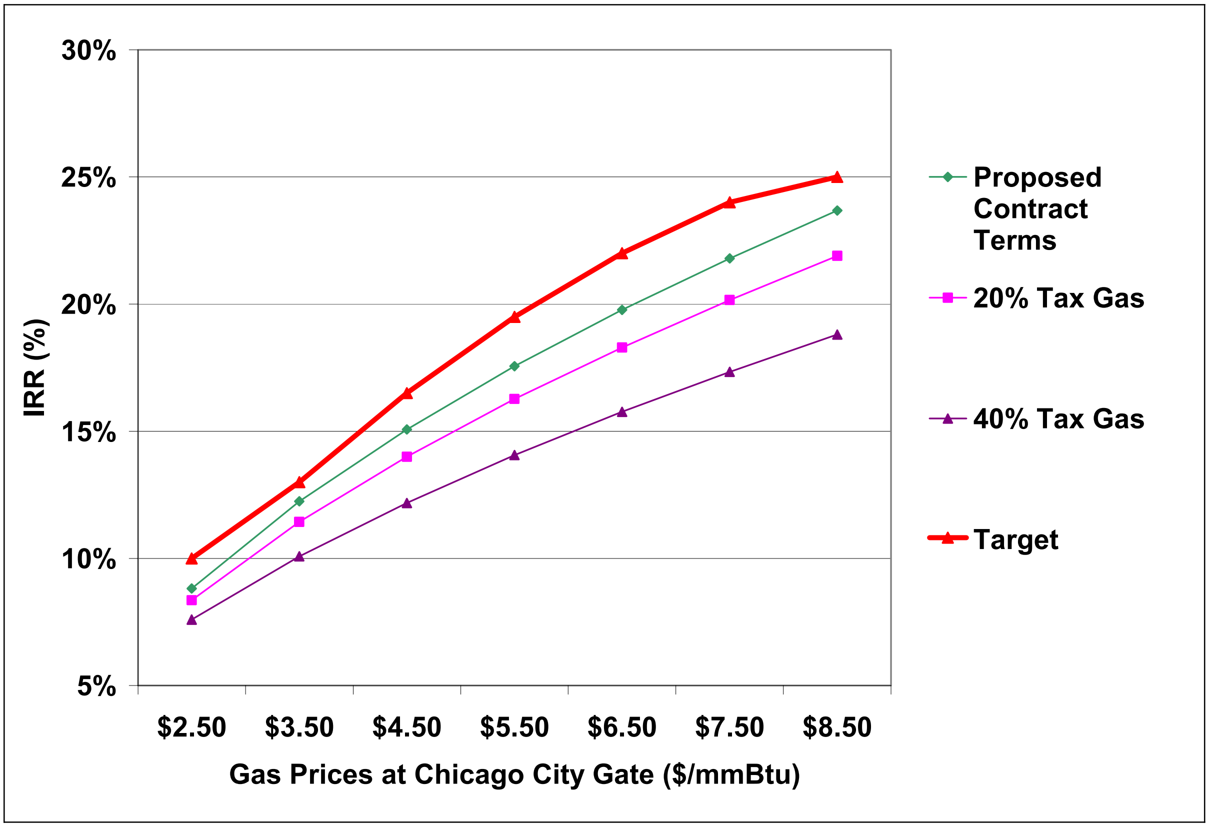
Figure 40 and Figure 41 show the impact of such tax gas rates on the real IRR from the effective date of the contract.

Figure 40. Real IRR for the Alberta Project under Conditions of Fiscal Risk



Source: PVM Model

Figure 41. Real IRR for the Chicago Project under Conditions of Fiscal Risk



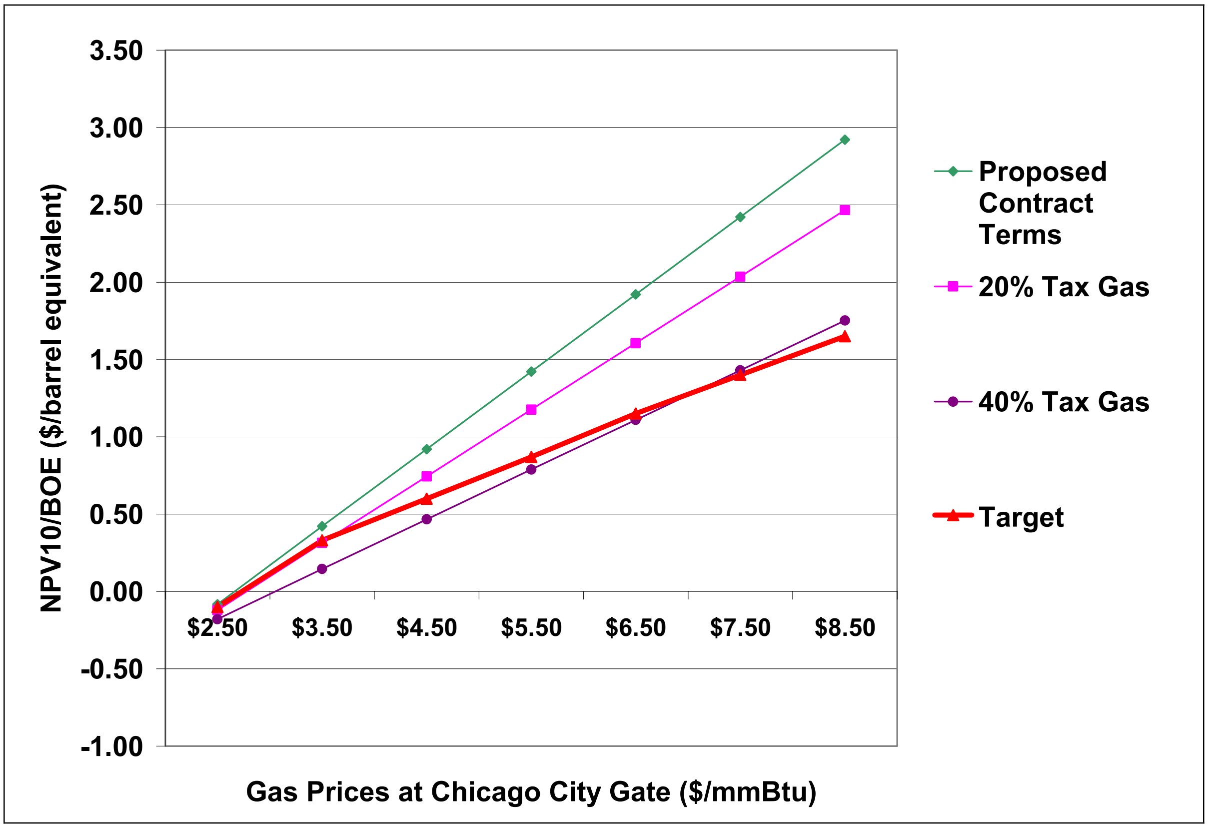
Source: PVM Model

The above chart (Figure 41) illustrates how, with a 20 percent tax gas, the IRR for the Alberta project would straddle the target rate, while the IRR for the Chicago project would be well below the target rate.

At 40 percent tax gas, the IRR would be well below the target across the entire price range for both the Alberta and Chicago projects.

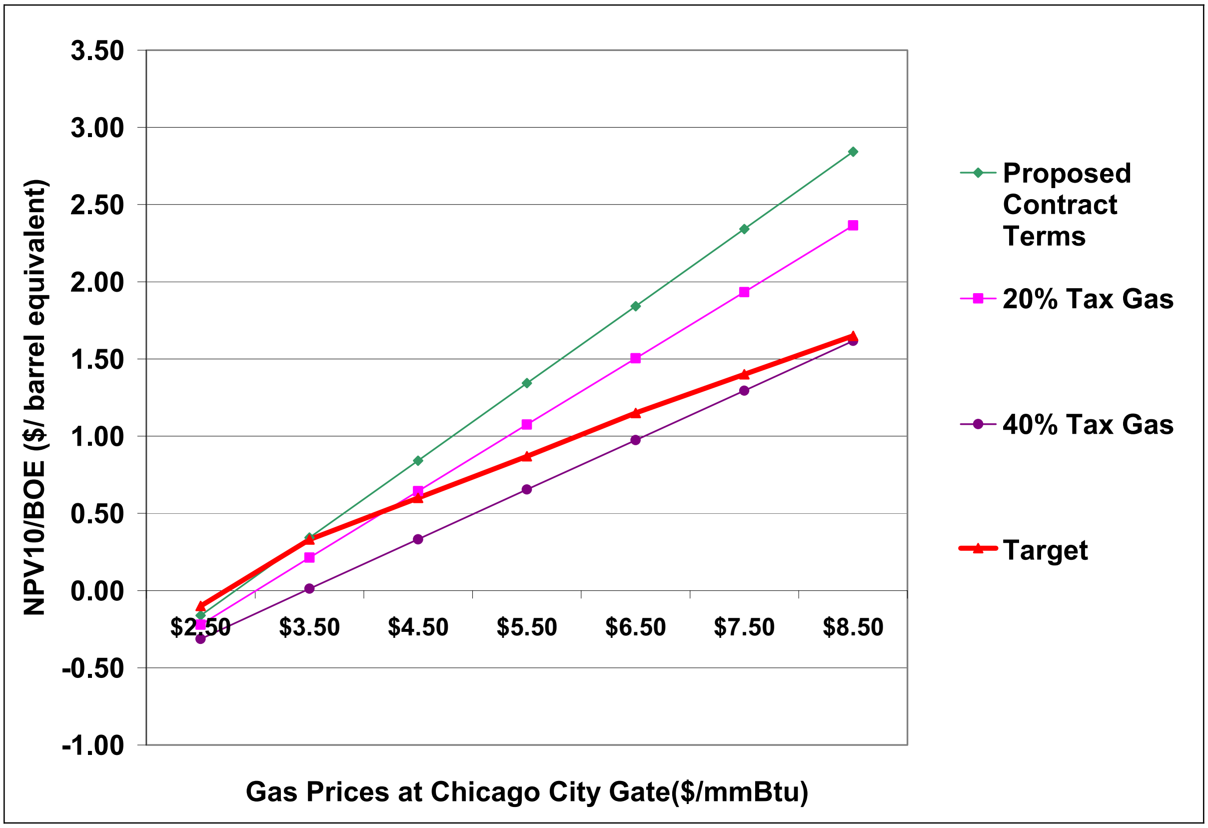
However, the project would not only be a poor project in terms of IRR. The following chart shows the NPV10/BOE compared with the competitive target values.

Figure 42.Real NPV10/BOE for the Alberta Project under Conditions of Fiscal Risk



Source: PVM Model

Figure 43. Real NPV10/BOE for the Chicago Project under Conditions of Fiscal Risk



Source: PVM Model

A tax gas rate of 20 percent would make the project unattractive at low prices, and much less attractive under average and high prices. A tax gas rate of 40 percent would make the project highly unattractive, in particular if prices drop after the commencement of operations.

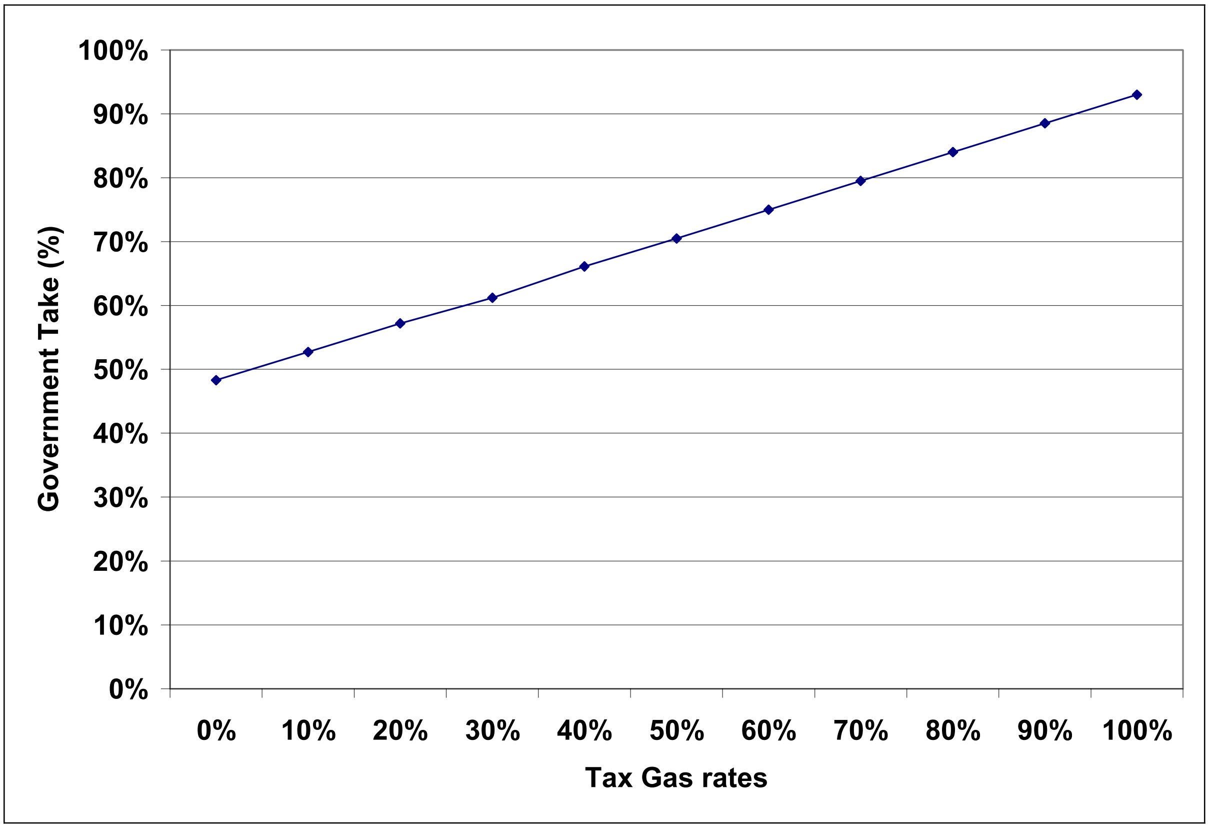
In other words, if the sponsors would have known from the beginning that they would be faced with a 20 or 40 percent tax gas rate, then they would not have proceeded with the project.

However, at the commencement of project operations, all their capital expenditures have now become sunk cost. The sponsors, therefore, will have lost their bargaining power and will no longer have the option not to complete the project. The remaining cash flow is now so profitable, even with 40 percent tax gas, that they have no option but to continue the project.

It should be noted that these are scenarios based on decisions on the part of a responsible legislature gaining the best possible revenues for the state under conditions of high prices.

The following chart illustrates the total government take for the Alaska gas project for different tax gas rates for a price of $5.50 per mmBtu.

Figure 44.Total Government Take for Different Tax Gas Rates for the Alberta Project at $5.50 per mmBtu



Source: PVM Model

A tax gas rate of 20 percent would result in a total government take of 57 percent, and a rate of 40 percent would result in a government take of 66 percent (note that at 100 percent tax gas, the total government take is still below 100 percent because of the fact that the midstream is still creating the same positive cash flow to producers).

These government take rates are well within the range of typical overall government take rates in North America and Europe, which range from 40 to 78 percent, with the U.S. Gulf at the low end and Norway at the high end.

Therefore, it would be a plausible scenario that a legislature at the commencement of the gas pipeline operations and in the absence of fiscal certainty would consider tax gas rates in the 20 to 40 percent range reasonable after a period of prolonged high gas prices.

The fact that the scenario is plausible makes the fiscal risk for the investors very high.

In other words, lack of fiscal certainty would expose investors to:

- Significant possible erosion of value under average and high prices to the point where the project becomes unattractive, when taking into consideration the capital invested; and
- Very significant exposure to downside price and cost overrun conditions.

For the giant Alaska gas project, investors cannot take this risk. It is for this reason that fiscal certainty is required if this project is to be realized, despite the huge net cash flow and NPV10 at average and high prices, based on the proposed contract.

5.1.11 PPT Credit of 35 Percent

Prior to discussing the balance of the fiscal principles, it is important to discuss the PPT credit of 35 percent on the GTP and feeder lines. Table 33 and Table 34 illustrate the difference in real IRR for the Alberta project for the proposed contract, both without and with the PPT credit of 35 percent on the GTP and feeder lines.

Table 33. Importance of PPT Credit on GTP for the Alberta Project

Price ($/mmBtu)	2005 Terms	No GTP	Proposed Contract	Target
	Percent			
2.50	7.6	8.7	9.1	10.0
3.50	11.8	13.5	14.0	13.0
4.50	15.2	17.3	17.8	16.5
5.50	18.1	20.5	21.2	19.5
6.50	20.6	23.4	24.1	22.0
7.50	23.0	26.0	26.7	24.0
8.50	25.1	28.3	29.1	25.0

Source: PVM Model

Note: Natural gas prices are expressed in $ per mmBtu at Chicago city gate.

Table 34. Importance of PPT Credit on GTP for the Chicago Project

Price ($/mmBtu)	2005 Terms	No GTP	Proposed Contract	Target
	Percent			
2.50	7.5	8.5	8.8	10.0
3.50	10.5	11.9	12.2	13.0
4.50	12.9	14.7	15.1	16.5
5.50	15.1	17.2	17.6	19.5
6.50	17.0	19.4	19.8	22.0
7.50	18.8	21.4	21.8	24.0
8.50	20.5	23.2	23.7	25.0

Source: PVM Model

Note: Natural gas prices are expressed in $ per mmBtu at Chicago city gate.

As can be seen from the two tables, the PPT credit plays a vital role in making the project attractive in real IRR terms. Even with the PPT credit, the real IRR remains under the target values for the Chicago project. Without the PPT credit, the real IRR would slip well under the target rates.

The PPT credit of 35 percent on the GTP and feeder lines is therefore an essential component of the proposed contract and plays a very important role in meeting the objective of creating a more competitive project.

5.1.12 Balance of Fiscal Principles

The proposed contract provides the following balance among the six economic-financial fiscal principles under Section 43.82.210 (b) of the SGDA:

(1) The terms should improve the competitiveness of the project in relation to other development efforts aimed at supplying the same market.

The terms improve the competitiveness of the project in a significant manner with respect to a project ending in Alberta or in Chicago.

(2) The terms should accommodate the interests of the state, affected municipalities, and sponsors under a wide range of economic conditions, potential project structures, and marketing arrangements

The risk sharing and participation by the State of Alaska make it possible to accommodate the interest of the state and affected municipalities as well as the sponsors in a highly satisfactory manner. The increase in competitiveness of the project is achieved while maintaining substantial revenues for the state and affected municipalities. Nevertheless, under unfavorable cost and price conditions, the terms balance the interests in favor of the state and affected municipalities.

(3) The combined share of the economic rent to the state and affected municipalities should be progressive

The combined share of the economic rent of the state and affected municipalities increases under conditions of lower costs and higher prices and is modestly progressive.

(4) The combined share of the economic rent to the state and the affected municipalities should be back end loaded.

The combined share of the economic rent of the state and affected municipalities is significantly back end loaded.

(5) The share of the sponsors should compensate the sponsors for risks under a range of economic circumstances.

The share of the sponsors does not compensate investors effectively under unfavorable conditions of costs and prices. But for average cost, the rate of return is acceptable over the entire gas price range. The net cash flow and net present value discounted at ten percent are among the highest in the world under favorable cost and price conditions, while other profitability indicators are attractive. This provides a reasonable balance under the full range of economic circumstances.

(6) The terms should provide the state and affected municipalities with a significant share of the economic rent when discounted to present value under favorable price and cost conditions.

The terms provide the state and affected municipalities with a significant share of the economic rent when discounted to present value under unfavorable and favorable price and cost conditions. In general, the overall government take is highly competitive and attractive when compared with other jurisdictions marketing gas in the lower 48 states over large transportation distances.

5.2 Other Options

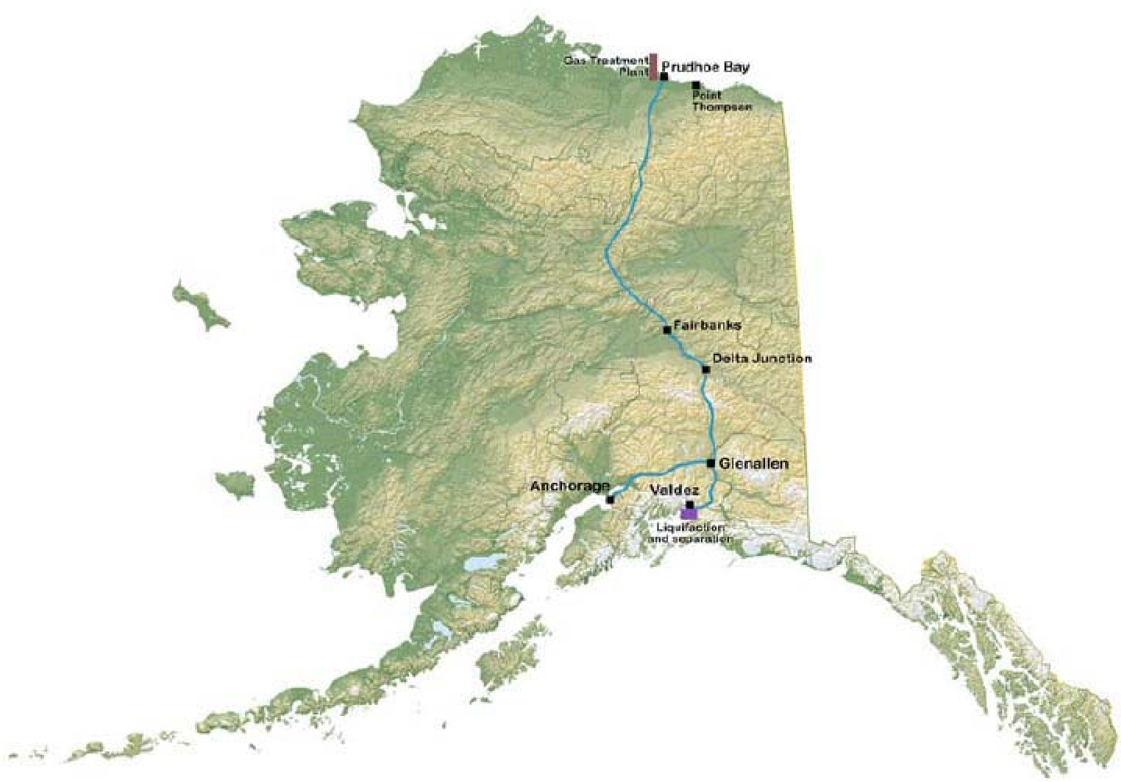
This section focuses on two other gas projects: the LNG option and the Y-Line option. The gas pipeline from the ANS to either Alberta or Chicago has already been described in Section 2 [Project Description] and is not reviewed here.

5.2.1 The LNG Option

This proposal seeks to transport about four bcf/d of ANS natural gas to Valdez, where it would be cooled and compressed into LNG and then transported via LNG tanker to the west coast of North America, where it would be re-gasified.

The project consists of a gas treatment plant in Prudhoe Bay; an 806-mile pipeline that parallels the TAPS oil pipeline all the way to Valdez; and an LNG plant in Valdez consisting of three 1.1 bcf/d liquefaction trains, LPG extraction facilities, and storage and loading facilities for both LNG and LPG. The project components are shown on the map below.

Figure 45. Map of LNG Options



Source: Information Insights, 2006.

From Valdez, the liquefied gas will be shipped by super-insulated tanker to west coast LNG terminals in the U.S. and Canada, where it will be re-gasified and sold primarily on the smaller Pacific Rim market. A 0.25 bcf/d spur line would bring gas from Glennallen to Anchorage to supply southcentral gas facilities and other in-state demand.

The project anticipates building a super large 56-inch diameter pipeline from the North Slope to Delta Junction, and a more conventional 48-inch pipeline from Delta Junction to Valdez, with a 24-inch spur line from Glennallen to Anchorage. The 56-inch pipeline is a necessary element in the project design because it is the most likely method for possible further expansion should ANWR open up and new large gas fields are discovered.

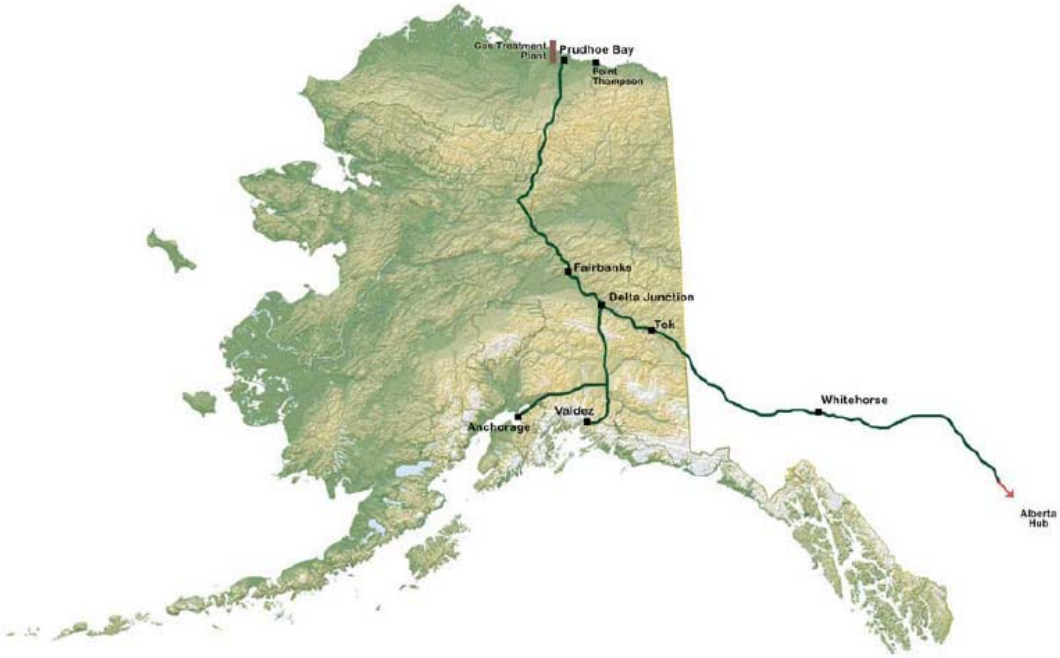
Cost estimates for this project are on the order of $26 billion in 2005 dollars and were obtained from the Alaska Gasline Port Authority [AGPA] web site, which posted the project description and cost estimates [from Bechtel] during December 2005. (see http://www.allalaskagasline.com/documents/AGPA_Project_Definition_v4_020106.pdf).

5.2.2 The Y-Line Option

The term Y-line refers to a junction point. For the Y-line option, ANS gas would be transported south to a junction point (the Y), where a portion would go to Valdez to be liquefied and transported by tanker, and a portion would go south to Alberta and Chicago.

The Y-line option consists of a 4.5 bcf/d pipeline running from a GTP at Prudhoe Bay to Delta Junction, Alaska, along the TAPS right-of-way, and then splitting into a 1.5 bcf/d pipeline to an LNG plant in Valdez and a 3.0 bcf/d (expandable to 4.5 bcf/d) pipeline to Alberta, Canada. The 3/1.5 Y-line scenario represents a best estimate as to the requirements of a Y-line project that would make the most economic sense given initial estimates of ANS gas reserves and other constraints. Like the previous projects, the model includes a 0.25 bcf/d spur line from Glennallen to Anchorage for in-state use. The project includes a 56-inch diameter pipeline to Delta Junction, with a more conventional 48-inch pipeline from Delta Junction to Alberta Canada, making those lines expandable. The line from Delta Junction to Valdez is a 36-inch diameter line, and the spur line is 24 inches in diameter. The Y-line is shown on the map below.

Figure 46. Map of Y-Line



Source: Information Insights, 2006.

Since a formal proposal has not been made for this project, assumptions, timing, and costs were based on those outlined for the LNG option. The project also includes liquefied petroleum gas (LPG) extraction facilities at Valdez, from which the LNG would be transported to west coast re-gasification terminals. The volume of LNG production could start at one bcf/d and increase over time to match market requirements. LPG would be shipped to markets in the U.S. and Asia.

5.2.3 Evaluating the Options

The economic and market analysis presented in this section offers a comparison of the Alaska natural gas pipeline project, the LNG project, and the Y-line project. These transportation options are not necessarily mutually exclusive. Multiple entities could contribute to portions of the pipeline project if commercial agreements are reached.

Information Insights, Inc. compared the three Alaska natural gas transportation options. (Information Insights, Inc. 2006) The analysis concludes that the sponsor group project provides the maximum benefit to the State of Alaska and its people.

If it is assumed that all three projects are able to obtain and transport the quantities of gas for which the projects are designed, then it appears that the three projects have the potential to generate similar streams of gross revenues to combined state and local governments over the life of the respective projects. However, the fact that the sponsor group currently owns the rights to the majority of the natural gas that would fill the pipeline lead the analysts to conclude that they would be unlikely to sell their gas into a pipeline that forces them to take a lower IRR than would be attainable from their proposed project.

The analysts also point out that if the producers would not sell their gas into another pipeline, the state could initiate legislative or legal action to reclaim the gas leases. However, the expected legal costs of such an action and the length of time it would take to produce a result that if successful, would have the consequence of reducing the net present value of the AGPA project to levels that would be significantly lower than benefits that could be obtained through the sponsor group's project.

Table 35 summarizes the comparison of the three proposed pipeline projects in terms of the net present value (benefits) and jobs created over the project life.

Table 35. Summary Comparison of Three Proposed Projects

Item	Pipeline Project	LNG Project	Y-Line Project [5]
Year in which actual construction is expect to start	2011	2015	2016
Year in which the gas first flows	2015	2019	2020
Year assumed for the last gas through the project	2045	2049	2050
Net Present Value over Life of Project to Local Governments ($billion 2005)[1]	$4.7	$5.0	$5.3
Net Present Value over Life of Project to State Government ($billion 2005)[1]	**$22.2**	**$16.0**	**$19.1**
Net Present Value over Life of Project to Producers ($billion 2005) [2]	**$10.6**	**$5.4**	**$5.6**
Total Net Present Value over Life of Project ($billion 2005) [6]	**$37.5**	**$26.4**	**$30.0**
Total Pipeline Project Related Jobs During Construction[3]	88,031	136,047	110,062
Average per year Pipeline Project Related Jobs During Construction[3]	17,606	19,435	22,012
Total Pipeline Project Related Jobs After Construction[3]	56,040	90,981	74,945
Average per year Pipeline Project Related Jobs After Construction[3]	1,808	3,137	2,418
Total Jobs from State and Local Spending [3]	831,277	717,807	698,626
Average per year Jobs after construction from State and Local Spending [3]	26,758	24,082	22,433
Total Jobs all sources all years [3]	975,348	944,835	883,634
Average State and Local Spending Per Year After Construction ($billion 2005) [4]	$1.7	$1.6	$1.5
Average Pipeline Project Spending Per Year After Construction ($billion 2005) [4]	$0.4	$0.7	$0.6
Total State, Local & Pipeline Project Spending After Construction ($billion 2005) [4]	$66.4	$65.1	$61.7
Reduction in NPV over life of project due to the destruction of value ($billion 2005) [2]	**0**	**$5.2**	**$2.8**
Total number of jobs lost over life of project due to the destruction of value[3]	-	199,565	107,458
Total Jobs all sources all years minus jobs lost due to value destruction [3]	**975,348**	**745,270**	**776,176**

Notes:

1) Assumes a 5 percent discount rate.
2) Assumes a 12 percent discount rate.
3) Includes direct, indirect and induced jobs, where one job is a full or part-time job over the course of a single year.
4) Includes direct spending in real 2005 dollars
5) Y-Line is delayed one year further from the LNG project because it is assumed that the same four-year process of getting permits for an AlCan project will happen with the Y-line. It does not make economic sense to start the LNG part of the Y-line earlier than an AlCan section can start since the combined portion of the pipeline will otherwise be half empty for an extra year and cause increased tariffs.
6) Assumes a 12 percent discount rate for producer value and 5 percent rate for state and local value and add the three together.

Gas price assumptions are as follows: i) Pipeline project: $5.33 /mm Btu (Chicago); $4.33/mmBtu Alberta; ii) LNG project: $4.54/mmBtu U.S. and Canadian West Coast average LNG; $4.15/mmBtu B.C. LNG; iii) Y-Line Project: $5.33/mmBtu (Chicago); $5.13/mmBtu LNG

5.2.3.1 Qualitative Considerations[62]

The SGDA contemplates that if a qualified applicant and proposed project plan are presented, then the commissioner of revenue would be authorized to develop a commercial contract for development of the stranded gas.[63] The administration chose to negotiate to develop a commercial contract in lieu of pursuing the alternative of litigation. The state has extensive experience with litigation with the producers. The ANS royalty litigation began in the late 1970s and concluded with settlements in the 1990s. The litigation over TAPS rates began in 1977 and was settled seven years later. Absent settlement, the presiding administrative law judge at FERC publicly stated that it would have lasted eight or ten years longer. The Exxon Valdez litigation has been ongoing for 17 years. The ANS producers have demonstrated their commitment to litigate aggressively, extensively, and expensively over what they view as the fundamental economic issues related to their interests in Alaska.

The administration's objective, reinforced by the mandate of the SGDA, was to undertake commercial negotiations as the best way of securing a gas pipeline for the state. The litigation alternative appeared far slower and less promising of certainty. The state has concluded that taking the leases back will involve considerable time and uncertainty that would act to the detriment of state's interest. This situation would apply to the TransCanada and ANGPA proposals.

Given that the other applicants do not have rights to ANS gas, it would take a long time to litigate a case that might ultimately provide other applicants access to ANS gas. This time delay would result in a reduction in the net present value of the project. The reduction in project net present value associated with time delays were presented in the section above on economic and market analysis (Section 4). Also, in the event that the sponsor group's proposed project does not go forward, the state may have to go through another process in which the state would have to put the leases out to bid, resulting in further uncertainty and time delays and uncertainty regarding the parties that may be successful in obtaining the gas.

5.2.4 Other Applicants

This section reviews organizations that submitted proposals to move Alaska's natural gas supplies to market. The information presented in this section is based on publicly available documents that can be accessed at the following websites:

- Alaska Department of Revenue (www.revenue.state.ak.us/GasLine/index.asp);
- Alaska Gasline Port Authority (AGPA) (www.allalaskagasline.com); and
- Alaska Natural Gas Development Authority (ANGDA) (www.angda.state.ak.us/).

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[62] As the SGDA process has advanced, both the legislative and executive branches of the state have been presented with analysis of the obligations of the producers under the Prudhoe Bay and Point Thomson leases to develop and market gas.

[63] See, e.g., Alaska Statute § 43.82.200 ("the commissioner may develop a contract that may include…"), Id. at § 43.82.210 ('the commissioner may develop proposed terms for inclusion in a contract…for periodic payment in lieu of one or more of the following taxes…"), see also Id. at §§ 43.82.220; 43.82.230, and 43.82.400 ("the commissioner shall prepare a proposed contract that includes those terms and shall submit the contract to the governor").

5.2.4.1 Alaska Gasline Port Authority (AGPA)

Section 29.35.600 of the Alaska Statues enables the formation of a port authority whose purpose is to provide for the development of a port or ports for transportation related commerce within the territory of the authority. AGPA is a municipal port authority established in 1999 by the municipalities of the North Slope Borough, Fairbanks North Star Borough, and the city of Valdez in accordance with the Alaska Municipal Port Authority Act. The following information is taken from the AGPA website (2006).

AGPA submitted an application under the SGDA on February 27, 2004. After a series of meetings with the state, AGPA withdrew its application in exchange for an agreement between the state and AGPA. Under the terms of the agreement, AGPA could resubmit its application before March 31, 2005. AGPA resubmitted its application on March 30, 2005, to allow for potential negotiations of the royalty and severance tax obligation by the gas producers through an AGPA project. The commissioner of revenue approved the application on May 5, 2005, under the condition that AGPA show proof within three months that it meets one or more of the sponsor qualification criteria in the SGDA as specified in AS 43.82.110(2)(A) – (E). AGPA did not meet the conditions listed in the ADOR conditional acceptance letter; therefore, that application was never approved and time to submit a new application has expired. On August 22, 2005, AGPA submitted an updated offer to the state for the purchase of ANS natural gas and the construction of an all-Alaska gas pipeline to carry it to market.

As described in the updated offer, the AGPA project includes an 800-mile, 48-inch gas pipeline parallel to the TAPS from Prudhoe Bay to Valdez, along with a 125-mile spur line from Glennallen to the Mat-Su Borough for injection into the ENSTAR natural gas distribution system. More recently, the AGPA has discussed a project that would transport three bcf/d to the Canadian border and one bcf/d to Valdez. The project also includes liquefaction and LPG (primarily commercial propane and butane) extraction facilities at Valdez, from which the LNG would be transported to west coast regasification terminals. The volume of LNG production could start at one bcf/d and increase over time to match market requirements. LPG would be shipped to markets in the U.S. and Asia.

AGPA currently has several memorandums of understanding (MOUs) with several west coast regasification terminals in various stages of development, including one at Kitimat, British Columbia. AGPA contends that for gas transported to the Kitimat LNG terminal, the project would not be subject to the Jones Act, as the gas composition will be altered through liquid extraction at the receiving terminal in Canada.[64] However, an information letter from U.S. Customs and Border Protection indicates that the LNG would not be altered sufficiently to qualify as a new and different product (PFC Energy, 2006b). The feasibility of a Kitimat LNG terminal is also uncertain:

> PFC Energy's evaluation of the Kitimat LNG project indicates that while it is likely to receive regulatory and environmental approvals, its relatively remote location means that it will receive significantly lower prices for regasified LNG than receiving terminals closer to major consuming centers in

[64] Section 27 of the Merchant Marine Act of 1920 (the Jones Act) reserves trade or transport rights between coastal ports of the United States to vessels built in the U.S., registered in the U.S., and manned with U.S-citizen crews.

> California. This is a disadvantage in both attracting LNG supply and maintaining high plant utilization during seasonal declines in demand. Given these disadvantages, the terminal is considered unlikely to secure financing for construction. (PFC Energy, 2006b)

AGPA has a MOU with the American Shipping Group/Totem Ocean Trailer Express (TOTE). TOTE, as a subsidiary to American Shipping Group, has operated a fleet of cargo ships serving Alaska since 1975. TOTE's MOU with AGPA anticipates that AGPA would build and own the vessels and TOTE would provide advice and guidance during construction of the ships and operate them for AGPA after they are commissioned (Bradner, 2006) TOTE's MOU and proposal to AGPA consists of TOTE providing U.S.-built LNG ships in full compliance with the Jones Act for gas shipped to U.S. west coast LNG receiving terminals with a Jones Act-compliant price quote that is competitive with foreign-built LNG tankers (PFC Energy, 2006b).

AGPA intends to apply for the State of Alaska's 12.5 percent of royalty of ANS gas at fair market value. AGPA also intends to acquire additional gas supplies through commercial negotiations with the gas producers, and if required, will utilize its authority to purchase ANS gas at fair market value. In addition, AGPA intends to offer the producers an opportunity to build and operate parts of the project. AGPA has been unable to convince the gas producers of its commercial viability, or that this proposal is the best alternative for transporting the gas to market, so the producers have not entered into agreements to sell gas to AGPA or agreed to ship gas on its pipeline. AGPA has filed suit against the producers in the U.S. District Court in Fairbanks alleging anti-trust claims that AGPA has unlawfully been denied access to the gas necessary to make the LNG project viable. It is not clear whether AGPA will prevail on the merits and it is expected that the producers will vigorously defend the lawsuit. It is likely that resolution will take a number of years.

As a municipal entity, AGPA is exempt from federal and state income taxes. In 2000, the Internal Revenue Service accorded AGPA tax exempt status as a non-profit corporation. One of the cornerstones of AGPA's proposal is a claim that it offers the state an increased price for gas through the benefits of the AGPA tax-exempt structure. Moreover, the concept of a public entity owning a portion of a natural gas pipeline within Alaska may present significant benefits for transportation of state royalty gas to in-state users.

As noted above, AGPA submitted an updated offer to the state to enable AGPA to acquire ANS gas in sufficient quantities to allow for the construction of the AGPA project. Even if this offer is not accepted, AGPA could participate in the development of a spur line from Glennallen to Palmer and/or a LNG project in southcentral Alaska by bidding for pipeline access during the initial open season or, in the event of a pipeline expansion, a subsequent open season.

5.2.4.2 TransCanada

TransCanada[65] is the leading natural gas pipeline company in Canada. In addition, Foothills Pipe Lines Ltd. (Foothills), a wholly-owned subsidiary of TransCanada PipeLines, Ltd. and

[65] TransCanada includes the TransCanada Corporation and the Alaskan Northwest Natural Gas Transportation Company, a wholly-owned subsidiary of the TransCanada Corporation.

Westcoast Energy, Inc., holds the certificates granted by the government of Canada under the Northern Pipeline Act of 1978 to build the pipeline in Canada for the transportation of ANS gas.

TransCanada proposes to construct a 1,710-mile natural gas pipeline from Prudhoe Bay to a major pipeline infrastructure system in Alberta that is in proximity to the original routing of the ANGTS. The pipeline being proposed by TransCanada is a 48-inch diameter high-pressure pipeline that has an initial design capacity of 4.5 bcf/d and can be expanded to approximately 5.9 bcf/d by adding additional compressor units.

The pipeline route would parallel the existing TAPS right-of-way until Delta Junction where it would follow along the Alaska Highway to the international border between Alaska and Yukon. Foothills would construct the Canadian portion of the pipeline that will connect with the Alaskan section at the Yukon border. The Canadian section of the pipeline will continue to follow the Alaska Highway to the Alberta border at Boundary Lake. Foothills would extend the existing pipeline network in Alberta to connect with the project at Boundary Lake. A combination of existing and expanded pipeline infrastructure could provide sufficient capacity for ANS gas to most major lower 48 U.S. and Canadian markets.

TransCanada submitted an application under the SGDA on June 1, 2004. The state approved TransCanada's application on June 16, 2004, and entered into a reimbursement agreement with TransCanada on August 26, 2004.[66] TransCanada and the state had discussions over major principles relating to their application. The state and TransCanada achieved consensus on most major issues and started to work on terms of a contract. The negotiations were discontinued when the state decided that it was in its interest to negotiate a contract with the sponsor group as they had the rights to the ANS gas which would lead to a more timely development of an Alaska gas pipeline. TransCanada has been granted important rights and easements in Canada for a natural gas pipeline to transport Alaska gas to the lower 48 states. It is possible therefore, that TransCanada could participate in the Canadian portion of the project.

TransCanada is a pipeline company and not an owner of ANS gas. Because it is not a gas owner, the argument can be made that TransCanada has less interest in low tariffs; conversely, the argument can also be made that, as operator, TransCanada would have a greater interest in transporting as much gas from as many shippers as possible—increasing access to the pipeline by explorers.

TransCanada asserts it has the ability to build a low-cost pipeline from Prudhoe Bay to the major pipeline infrastructure system in Alberta, Canada, with the lowest possible tariff and the highest netback price to the state and producers. This estimated high netback price is primarily associated with the market diversification provided by the existing infrastructure, rather than going to a single market. The challenge for TransCanada would be to develop a commercially viable project so that the gas producers and state would agree to ship on TransCanada's pipeline. Because TransCanada would only be involved in a pipeline, fiscal issues related to its proposed project would center mainly on taxes imposed on the pipeline, access to the pipeline, and tariffs. Although a fiscal contract with TransCanada would apply

[66] As specified in AS 43.82.240(a), the commissioner of revenue may condition the development of a contract under the SGDA on an agreement by the applicant to reimburse the state for the reasonable expenses of independent contractors.

only to the pipeline and accordingly be more limited in scope than one involving the ANS producers, in the event that the state went forward with TransCanada as the sponsor of the pipeline, it would be necessary to negotiate a separate fiscal contract with the producers who own the gas on which the project rests to provide the upstream aspects of the project with the fiscal certainty the producers say is essential.

TransCanada also asserts that it is the best entity to deliver the Canadian portion of the Alaska gas pipeline project. Certainly any pipeline project would have the option of integrating deliveries with the existing Alberta pipeline network. Because it owns most, but not all, of this network, TransCanada can argue that it is well prepared to ensure an Alaska pipeline project is integrated most efficiently with the existing infrastructure. Evaluation and negotiation of integrating deliveries with the existing infrastructure can be expected to be part of the planning of any Alaska pipeline project

An additional consideration is that companies that are now subsidiaries of TransCanada were among the ANGTS sponsors that submitted state and federal right-of-way applications in the early 1980s. The ANGTS sponsors secured a right-of-way across federal lands in Alaska on December 1, 1980. On April 19, 2004, TransCanada signed a MOU with the state under which the state agreed to resume processing the pending application for the state right-of-way lease for the ANGTS; TransCanada submitted an updated application to the ADNR on June 1, 2004. If the state right-of-way lease is approved, TransCanada has agreed to convey the right-of-way to any holder of a final FERC certificate of public convenience and necessity to construct an Alaskan pipeline that connects with its existing facilities.

5.2.4.3 Alaska Natural Gas Development Authority (ANGDA)

ANGDA was created by a voter referendum in 2002. ANGDA was established to provide one or more of the following services and functions in order to bring ANS natural gas to market:

(1) acquisition and conditioning of ANS natural gas;

(2) design and construction of the pipeline system;

(3) operation and maintenance of the pipeline system;

(4) design, construction, and operation of other facilities necessary for delivering the gas to market and to southcentral Alaska;

(5) acquisition of natural gas market share sufficient to ensure the long-term feasibility of the pipeline system project.

ANGDA is a public corporation and an instrument of the State of Alaska within ADOR. However, ANGDA has a legal existence independent of and separate from the state. It is governed by a board of directors consisting of seven members from the general public appointed by the governor and confirmed by the legislature. ANGDA is in discussions with all parties to assist in the development of Alaska’s natural gas resources, and particularly to deliver gas to southcentral Alaska and provide benefits of gas commercialization to a large number of Alaskan communities.

ANGDA did not submit a SGDA application.

ANGDA had initially focused on a LNG project in southcentral Alaska, which would require a pipeline built across Alaska, but it has since deferred to AGPA on this project. Most recently, ANGDA has focused on a proposed Glennallen to Palmer spur line. On April 4, 2005, ANGDA submitted to the state an application for a “conditional use” right-of-way lease for a pipeline route that connects Glennallen to the southcentral Alaska natural gas distribution system. This proposed spur line originates at the TAPS right-of-way approximately two miles north of Glennallen and ends southwest of Palmer near the Glenn and Parks Highway interchange. The spur line will tie into the existing ENSTAR pipeline. The commissioner of natural resources issued a proposed decision that it was in the public interest to issue the right-of-way lease for the spur line on February 24, 2006.

5.2.4.4 Other SGDA Applicants

Enbridge, Inc., submitted an application under the SGDA on April 30, 2004. The application was accepted by the state, but Enbridge, Inc., did not enter into a reimbursement agreement with the state, and negotiations regarding a fiscal contract have not been conducted.

MidAmerican Energy Holdings Company and MEHC Alaska Gas Transmission Company, LLC (collectively, MAGTC), submitted an application on January 22, 2004. The application was accepted by the state, but MAGTC did not enter into a reimbursement agreement with the state. MAGTC withdrew its application in March 2004.

6 Mitigating Project Risk

Any major project has inherent risk factors that must be assessed during the decision-making process. For the state there are risks associated with the proposed contract and subsequent project; an assessment of these risks is part of the fiscal interest finding. This section of the finding and determination, identifies and describes the risks inherent to the project, the articles of the contract that address these risks, and the steps the state would take in the future to mitigate these risks.

Project risks are categorized into four general categories:

- Economic Risk. Economic risks are associated with building, operating, and maintaining the project, market-related conditions such as commodity prices and competition from foreign sources.
- Resource Risk. This risk concerns finding insufficient gas reserves to sustain the project throughout its useful life.
- Political and Regulatory Risks. This category includes the international, national, regional, and local political issues associated with the project as well as the risk of short-term social disruptions associated with economic booms that would occur if the project goes forward.
- *Force Majeure*. *Force majeure* events are unavoidable events such as natural disasters that result in the inability of a party to perform or deliver contractual obligations.

These various categories of risks not only have the potential to negatively affect the project, but also Alaskans and their communities. Some of these risks are shared between the state and potential partners, while others may be borne by individual communities or regions. The following sections describe the risk categories, identify the articles of the contract that address these risks, and identify mitigation steps the state could take to reduce the identified risks.

6.1 Economic Risk

Economic risks cover issues of cost overruns, completion risks, marketing risks, and transportation and shipping risks. Financing risks are integral to the analysis presented in Section 7.

6.1.1 Cost Overruns

Potential capital cost overruns could result in a considerable negative economic impact on the project. Large cost overruns would increase gas shipping costs and could raise the delivered cost per mmBtu of natural gas beyond gas market prices. TAPS experienced a cost overrun of about $1.5 billion or 23 percent more than projected (GAO, 1978). Most of the TAPS cost overruns were generated by additional direct labor hours needed to complete, which resulted primarily from unexpected site conditions and construction difficulties. This emphasizes the need for a rigorous, disciplined project planning and design process prior to making construction commitments.

Construction of a natural gas pipeline would benefit from the lessons learned from the problems that plagued the TAPS during its construction. However, cost overruns are a distinct possibility due to the magnitude and complexity of the project. A recent study by Flyvbjerg et al. (2003) on mega-projects and risk documents the difficulties in planning and managing projects of this size and scope. The effects of general or regional cost escalation could contribute to cost overruns. The high level of activity in the province of Alberta is already causing significant regional cost escalation which could harm the Alaska gas project. The economic analysis presented in Section 5.1 indicates that cost overruns of 20 percent to 50 percent could make the project uneconomic under low price conditions. The overall level of inflation or monetary market forces may result in higher interest rates that could affect the ability to finance the project.

Under the proposed contract the cost overrun risks are shared proportionately between the state and the producers. If cost overruns occur, the netback price will go down in approximately the same basis for both parties but the profits associated with the pipeline may increase depending on the FERC’s evaluation of the cost increases and objectives regarding rates of return to investors.

6.1.2 Completion Risk

Completion risk is a risk inherent to any large-scale project such as the natural gas pipeline. It includes both the risk that a project may not be completed, as well as the risk that completion is delayed. A wide range of obstacles can adversely impact project completion including manpower, material and/or equipment availability; design and constructability issues; and unforeseen major political or social shifts. The ability to complete a project of the magnitude of the Alaska Gas Pipeline can also be affected by major global instabilities which may not be directly affecting Alaska or the central North American continent. Logistics will be one of the critical sources of completion risk, not only because of the sheer magnitude of this project, but also due to its broad span: politically, geographically, environmentally, and technologically. These same four latter factors also provide a wide spectrum of potential grounds for litigation, further compounding completion risk.

Completion risk also changes as a project progresses. Early in the project life, when uncertainties—and, therefore completion risk—are greatest, relatively few dollars will have been spent—therefore the risk is significant, but the magnitude of dollars *at* risk is low. One of the major purposes of spending front-end engineering, planning, permitting, and communication dollars is to minimize the risk that the project will not be completed, or will not be completed on time. This front-end spending, and the work done as a result of this spending, is so very critical to ensure both completion risk and cost-overrun risk are minimized during the implementation phase of the project, that major projects are not rigorously scheduled until near the end of this period, when the risks, challenges and uncertainties facing a project are fully understood. This risk mitigation is critical as the total dollars placed at risk grows during engineering—and particularly during the procurement, construction and startup phases of the project when the bulk of the project investment is made. Article 5 of the stranded gas contract related to work commitments is structured so that the process of risk mitigation can unfold as required.

6.1.3 Market Risk

There are several different facets of market risk: i) the risk associated with low commodity prices; ii) the risks associated with competition from North American and imported gas sources; and iii) the risks associated with taking gas as payment.

Gas Price Risk. As noted by the Energy Information Administration:

> Gas price risk is associated with the potential that future natural gas prices in the lower 48 states might be too low to recover all pipeline and production costs, along with an adequate rate of return. Gas market price risk is further enhanced by the 9- to-10-year permitting and construction period for a gas pipeline, which increases the possibility that market conditions and prices could have changed considerably by the time the pipeline goes into operation. For example, more than 35 North American liquefied natural gas (LNG) terminals, with more than 30 billion cubic feet of daily delivery capacity, have been proposed for completion over the next decade. Some analysts have concluded that LNG imports are a less expensive gas supply option for the lower 48 than the transportation of gas from the Alaska North Slope. If this is true and if a significant portion of the proposed North American LNG capacity is built, then gas prices might be lower than the breakeven cost for gas transported by an Alaska gas pipeline (EIA, 2004).

Price risk is mitigated by a gas marketing organization through the use of a variety of contracting and financial tools. Long-term contracting arrangements, short-term firm sales, and sales on a sport market all play a role in a gas marketer's sales contracting strategy. Financial hedging mechanisms, such as commodity futures trading, commodity option trading and other financial mechanisms are available at premiums that are commensurate with the level of risk they mitigate. Risks can also be shared with the buyer by means of a "cost collar". This mechanism protects the buyer from upside price risks above a specified ceiling level in exchange for the buyer agreeing to specified floor price. By this means the state sacrifices the benefit of prices above the collar in exchange for an assured floor price. Between the floor and the ceiling level, the market determines the selling price.

The contract contains several articles that result in a sharing of the gas market price risk between the state and the producers. The midstream payment (see Article 16) and the upstream facilities payments are based on gas throughput and will not vary with price. In general, the state's share of gas revenues decreases slightly under low prices. Conversely, the contract also provides for upstream cost allowances (see Article 20) of $0.224 per mcf payable by the state to the producers which increases risk to the state under low prices.

Competition from Other Gas Sources. An Alaska gas transportation project following the over-the-top route is no longer a viable option because of State of Alaska and federal legislation. However, Canadian companies have proposed a stand-alone Mackenzie Valley pipeline project that includes a 758-mile pipeline to transport 1.2 bcf/d of natural gas from the Northwest Territories to a point of interconnection with the natural gas transmission system in northern Alberta owned by NOVA Gas Transmission Ltd., a wholly-owned subsidiary of the TransCanada Corporation. [67]

Some think of the MacKenzie pipeline as a competitor to the Alaska gas pipeline. Certainly the two projects will be looking to common labor pools, similar contracting organizations, and similar markets for gas sales. It is very likely that the Mackenzie pipeline, based on present tentative construction schedules, would mitigate some cost overrun risks for the Alaska project by acting as a “warm-up” for an Alaska gas transportation project following the Alcan Highway route (Union Gas Ltd. March 2005). However, there is a possibility that the Mackenzie project could be delayed. If delays result in the Alaska gas transportation project beginning construction first, labor and equipment supply problems could delay the Mackenzie project. Moreover, if the larger (4 bcf/d) Alaska project were to come online before the Mackenzie project, there is concern that the increased gas supply will depress natural gas prices for a period, which could further delay the Mackenzie project (Union Gas Ltd. March 2005).

Marketing Risks. Under the contract, Alaska would take ownership and full financial responsibility of the gas and liquids it receives at the delivery point. As the owner of gas and liquids, the state would be responsible for arranging for their sale, either to parties in Alaska or to other parties at pipeline project terminus points. The state could also sell gas to parties further downstream of the proposed pipeline, but this would necessitate further transportation arrangements. This differs from the current arrangement, in which the state can elect to take payment in value rather than possession.

The necessity for marketing gas carries a long-term risk if technological change or other competing sources reduce the demand for natural gas or lower the prevailing long-term price of gas. For example, the most recent long run outlook by the U.S. Department of Energy projects electricity generation from coal fired power plants will grow faster than electricity generation from gas fired power plants, with the result that the share of electricity generated from natural gas will decrease from 18 percent in 2004 to 15 percent in 2030 (ADOR, 2006). Breakthroughs in wind energy and other technologies might make these technologies more cost-competitive than gas in the electricity generation market. Competition from imports of LNG in the lower 48 states could conceivably drive down prevailing market prices for gas. Although these market risks would also be present under a payment in-value arrangement, the state or its marketing agents would be responsible for anticipating and responding to these demand shifts under a payment in-kind arrangement.

The responsibility for marketing the gas may expose the state to greater financial risks. The state’s responsibility for marketing the gas and liquids would obligate the state to create its own marketing operation or contract out this function to a third party that would purchase

[67] The proponents of the Mackenzie Gas project are Imperial Oil Resources Ventures, Ltd., Imperial Oil Resources, Ltd., ConocoPhillips Canada (North), Ltd., ExxonMobil Canada Properties, Shell Canada, Ltd, and Mackenzie Valley Aboriginal Pipeline Limited Partnership (representing the interests of native peoples of the Northwest Territories). TransCanada has agreed to lend funds to the Mackenzie Valley Aboriginal Pipeline Limited Partnership for its share of project definition phase costs (in exchange for this funding, TransCanada earns a number of acquisition and expansion rights together with a financial return if the project goes ahead). Enbridge, Inc. also has a share of the Mackenzie project as natural gas liquids will be shipped via its existing oil pipeline to Norman Wells where they will enter the existing oil pipeline at Zama, Alberta (Union Gas Ltd. February 2005). In addition, Enbridge Gas Distribution operates the Inuvik gas distribution system in the Mackenzie Delta.

and resell the gas, or find and maintain a market for gas production. Either option would involve some level of transaction costs (See Section 8.3 for additional information on the state's gas marketing organization). There will also be risk engendered by the "take or pay" nature of the long term commitments for pipeline capacity that must be undertaken.

Some of the other potential costs to which the state, under the contract, would give up arguments that it does not owe include:

- holding production in a storage facility and related storage fees or costs;
- penalties that might be incurred as a shipper
- possibility that some buyers may not fulfill their purchase commitments and pay the state;
- the state is unable to receive similar value marketing its own gas;
- capacity management fails to protect the state's interest; and
- the price differential between Alberta and the downstream markets is less than the cost to transport the gas from Alberta to the market (Lukens Energy Group, 2004).

Some of the more obvious risks that are borne directly by the state are not incremental risks; they would be borne indirectly by the state even if royalties continued to be paid in value, and so are not incremental risks to the state. These risks include such factors as:

- volume of gas owned and transported by the state is not sold; and
- costs of unused transportation and treating capacity.

6.1.4 Transportation and Shipping Risk

If the state participates in the entire project, the state's shipper's risk is, in principle, proportionate to the producers'. However, as discussed above, the state does not control production and must rely upon other potential producers. The state has worked to reduce its share of shipper's risk by negotiating the protections offered in the capacity management article (Article 10).

Some potential risks that the state may face include

- scheduling penalties incurred for differences between daily volumes delivered into the pipeline and volumes scheduled for a delivery point;
- imbalance penalties incurred on a monthly basis for differences between volumes delivered into the pipeline and volumes scheduled for a delivery point; and
- operational penalties incurred for violating the pipeline's curtailment or operational orders issued to protect the operational integrity of the pipeline.

The capacity management article of the contract (Article 10) was created to manage these risks by ensuring that state gas can be moved to market without incurring other unreasonable risks or costs.

The article provides for a unique set of commitments between sponsor group and the state. These commitments have no parallel in the gas transportation industry. The article prescribes a procedure by which capacity commitment-related risks borne by the state with respect to the sponsor group are mitigated and balanced. These risks arise due to the state's commitment to take gas rather than cash as payment and assume responsibility to treat and transport that gas on a contract pipeline system. The treatment of these risks, and the prescribed procedures by which those risks are managed, are discussed below.

The complexity of the capacity management provisions in the contract creates a risk in the application of the provisions, particularly to unforeseen or marginal circumstances. This risk is mitigated by development of examples to illustrate application of the provisions, and by access to arbitration of disputes. The intent of Article 10 on the part of the state is clear. The state's need for capacity management provisions is also clear. Both factors should provide a solid contextual basis for arbitrated decisions. With respect to the magnitude and range of risks incurred due to the acceptance of firm capacity commitments, the state has chosen to allow the sponsor group to act on the state's behalf.

These capacity management provisions of the contract are designed to function over a range of scenarios that have the potential to occur over the term of the contract, including scenarios in which the pipe is not full, the state is burdened with excess firm capacity as compared to the sponsor group, and the state lacks the capacity to move its produced gas to market. The state may not acquire firm capacity outside the terms of this article without voiding the producer commitments to manage firm capacity for the state. The effect of this constraint, on the state, is that all state royalties and taxes on gas outside this Contract must be taken in-value by the state.

The state has the right to unilaterally choose to cancel the commitments of the capacity management article, although that action would then expose the state to the risks discussed above. As circumstances change during the term of the contract, the state's evaluation of these risks, and potential benefits, may well change.

Risks exist that the state will be unable to move gas to market or will retain responsibility for unused firm capacity commitments. The purpose of Article 10 is to ensure those risks are proportional to the risks incurred by the producer shippers. The state had a third party study undertaken to measure and evaluate those risks (Lukens Energy Group and Black & Veatch, 2006). The following discussion summarizes the study findings relative to disproportional risks, and also the absolute risks inherent to taking firm capacity commitments.

Five sources of this risk have been identified:

1) Initial allocation,
2) Insufficient capacity,
3) Excess capacity,
4) Inability to obtain market value, and
5) Costs of capacity reallocation thresholds.

The risks incurred due to each of these five sources are discussed below.

The mechanisms available in Article 10.1 for initial allocation of capacity appear sufficient to ensure proportional allocation of capacity between producers and the state. No disproportionate or absolute risks were estimated to exist due to the capacity allocation provisions of Article 10.1.

Proportionality between the producers and the state, in situations where insufficient capacity is available, is largely maintained in Article 10.2. The exception is the opportunity for the producer to buy gas from the state, rather than provide capacity. A producer's ability to purchase state gas without reducing its own production is constrained by its access to available capacity. The aggregate disproportionate risk to the state of insufficient capacity is estimated to range from 9 to 80 million dollars on a NPV basis, a risk that is .05% to 0.42% of the total NPV benefits to the state.

The absolute magnitude of excess capacity risk to the state is estimated to range from 0.5 to 2.1 billion dollars NPV, equivalent to 2.7% to 11.3% of the total NPV to the state. This magnitude of risk assumes no additional reserves are found for delivery to the project. The likelihood of this magnitude of excess capacity risk occurring is considered small, given the huge resource base, the level of industry activity and the incentives for exploration and development available to industry. Disproportionate excess capacity risk borne by the state was estimated in the study to be 27 to 193 million dollars on an NPV basis, equivalent to 0.14% to 1.02% of the total NPV benefits to the state. This disproportionate risk has been largely eliminated by contract language revisions implemented subsequent to the study.

The provisions of Article 10 were reviewed to determine whether the state is at risk due to inferior ability to obtain market value for state gas, created by use of inferior classes of capacity. Since the article specifies that all capacity be allocated on a proportional basis, it was interpreted that the producer and state share equally in the opportunity to obtain fair market value for gas sold, and that no disproportionate risks exist for the state.

Article 10.4 creates a threshold below which excess capacity imbalances need not be corrected. Evaluation of this mechanism demonstrated that the state is likely to benefit from this provision in a situation in which excess capacity exists. The benefit to the state is estimated to range from 5.8 to 79.4 million dollars on an NPV basis, equivalent to 0.03% to 0.42% of the project NPV benefits to the state.

Issues remain about the details of implementing Article 10. Nevertheless, the magnitude of estimable risks to the state incurred by making firm capacity commitments is quite reasonable, particularly when considered relative to the value to the state of the entire project. In addition, these risks appear to be largely shared proportionately between the state and producers.

6.2 Resource Risk

The resource risk is the difference between known gas resources within the project area and the amount of gas needed to make the project economically more attractive. Section 1.2 discusses the volume of known natural gas reserves and likely undiscovered gas reserves.

In total there is approximately 35 tcf of known recoverable ANS natural gas (ADNR, 2004). For the project to have a full gas line during the 30 years the project needs approximately 44 tcf; to have a full gas line for the term of the contract the project needs approximately 53 tcf of gas.

It is very likely that undiscovered gas reserves exist within ANS. The United States Geological Survey (USGS) has estimated the volume of technically recoverable conventional oil and natural gas resources in the North Slope that have not yet been discovered. The mean value estimate of the total undiscovered natural gas resource potential in the North Slope is 119 tcf (USGS, 2005). Combined with known reserves, the North Slope region is estimated to hold about 155 tcf.

The state and producers would proportionately share the resource risk of an under-utilized pipeline. However, producers can mitigate these risks by incremental investments in exploration and development. The state must rely upon other producers to produce gas from yet-to-find reserves to mitigate the risk of under-utilized capacity. In order to encourage further exploration and development of currently undiscovered gas, the terms of this contract will be available to other potential producers operating in the ANS, by means of the uniform upstream fiscal contract. The uniform upstream fiscal contract applies to new parties that are not signatories of the contract at hand. The upstream fiscal contract focus is to ensure that future producers and transporters of gas are provided terms equal to the current contract signatories.

An economic analysis with the PVM model indicates that increasing the produced and transported gas from 35 tcf to 44 tcf improves the internal rate of return to the sponsors by about 0.5 percent at the stress price of $ 3.50 per mmBtu at Chicago city-gate prices.

From the sponsors' perspective the benefits of increased production and transportation depend on the ownership of the additional gas. If the additional gas belongs largely to non-sponsors, the economic benefits to the sponsors are limited to the lower transport tariffs. If the additional gas belongs largely to the sponsors the improvement in economics will be as indicated above.

A 0.5 percent increase in rate of return would be a desirable increase in profitability. This would increase the probability that investments will be made in the project at the project sanction date. Nevertheless, the main beneficiaries of increased production and transportation of gas are the state and the affected municipalities, which will receive significantly more revenues proportionately with the increased volumes. In addition, the value of the state's gas increases because the average transport tariffs are lower in the future after paying the debt financing. It is in the state's best interest to take all steps required to increase the volumes to be produced and transported through the gas pipeline.

The existence of a new gas pipeline will by itself be a strong stimulus in promoting exploration as long as explorers perceive that there will be possible expansion capacity available.

6.3 Political and Regulatory Risk

Compared to international oil and gas development projects in some parts of the world, the Alaska natural gas pipeline project has minimal exposure to the more common political risks of expropriation of property, civil unrest, and other factors that the industry faces in other locations around the world. Political impacts that may occur with the project include strain in coordinating U.S. and Canadian processes, general social approval or disapproval, taxation issues, local hire concerns, and permitting constraints.

6.3.1 Coordination of U.S. and Canadian Efforts

Parts of the proposed gas pipeline would pass through the Yukon Territory, and the provinces of British Columbia and Alberta. There are outstanding issues of regulatory certainty, First Nations settlement agreements and land claims, and other issues that are yet to be resolved. As described in Article 8.1, regulation of the non-Alaska project for shipment of gas will be governed and controlled exclusively by applicable Canadian law for the non-Alaska project located in Canada. Therefore it is important to understand the Canadian laws and regulations that would apply to the proposed project.

Similar to FERC in the U.S., Canada has a federal energy regulator, the National Energy Board (NEB) as well as a state or provincial counterpart, the Alberta Energy and Utilities Board (EUB). The NEB is the Canadian federal agency which regulates inter-provincial and international energy imports and exports. The EUB is an independent, quasi-judicial agency of the Government of Alberta, whose mission is to ensure the discovery, development, and delivery of Alberta's energy resources; as well as over see utility services within the province of Alberta.

The most significant production area within the Canadian gas industry is the western Canadian sedimentary basin (the "WCSB"). WCSB is a maturing gas basin, as gas production reached a plateau recently at approximately 16.5 bcf/d, despite record drilling levels. (NEB, 2005 and TransCanada PipeLines, 2004) The NEB and EUB have projected steady and discernable declines in natural gas production in the WCSB beginning in the next two to three years.

By 2015, when the Alaskan pipeline is expected to begin operations, the NEB has projected that western Canadian gas production could decline to approximately 14 bcf/d from its current level of 16.5 bcf/d. A loss in gas production of this magnitude will result in significant excess capacity on Canada's pipeline infrastructure. Additionally, the demand for natural gas fuel to fuel oil sands development is growing. (EUB, 2004.) The NEB is forecasting that gas demand in Canada will increase to almost 11 bcf/d by 2015. (NEB, 2003) It is possible that by the end of the next decade Canada could be a net importer of natural gas.

Given the maturing and possibly declining WCSB gas production, specific benefits to Canada of the proposed pipeline have been identified, including: a larger and more efficient Alberta market hub, greater and more efficient utilization of Canada's existing pipeline infrastructure, opportunities to sustain and enhance Alberta's petrochemical industry, and increased development of Alberta oil sands resources.

6.3.2 Social Impacts

Social impacts are related to the potential social disruptions that occur with projects that create economic booms. Under the proposal contract terms, local municipalities and the state will be compensated with impact payments. These payments would address local economic and social impacts in communities that may be economically affected by the project (as required under AS 43.82.505) but will not be able to tax the project.

A report prepared for the Municipal Advisory Group by Information Insights identified about $125 million (2003$) in costs for local governments and others to address the potential impacts from the project. (Information Insights, 2004) The impact payments cited in the contract total $125 million and will be paid over a six-year period. The first payment would occur at the end of the calendar year immediately following project sanction.

The project will impact the communities and populations near it in Canada. Canadian law and policy require that these impacts be identified and addressed. There must be early and extensive consultation with First Nations' groups on major resource development projects. The Canadian Government is responsible for conducting adequate consultation; project proponents are responsible for ensuring that traditional knowledge from First Nations is incorporated into project design, and that agreements for pipeline access to their lands and benefit agreements with them are negotiated successfully. Successful negotiation of these agreements is necessary to mitigate the risks of delay and added costs that would otherwise result. See Section 8 for more discussion on issues related to Canada.

6.3.3 Taxation

Alaska can certainly not be considered a jurisdiction with high fiscal risk. The last significant change in Alaska taxation prior to the introduction of the PPT was in the production tax in 1989. The frequency of change is therefore very similar to changes in other North American or European jurisdictions.

Nevertheless, the risk profile of the Alaska gas pipeline project is highly unique, with possibilities for very high NPV10 values as well as possibility for significant economic losses. Therefore, in the absence of a stranded gas contract, it is possible that legislative adjustments would be made that would erode much of the profitability of the project. This matter is more fully explained in Section 5.1 of this report.

The stranded gas contract would have an overall government take that is in the middle of typical overall government take rates in North America and Europe. Therefore, it would be a plausible scenario that a legislature in the absence of fiscal certainty would consider tax changes within this range during the project's operating life. Section 1.1 clearly describes that the State of Alaska is potentially facing significant budget deficits under low or average oil and gas prices. This increases the possibility for tax changes if fiscal stability is not available through the contract.

In other words, lack of fiscal certainty would expose investors to

- Significant possible erosion of value under average and high prices to the point where the project becomes unattractive, when taking into consideration the capital invested; and
- Very significant exposure to downside price and cost overrun conditions.

Investors cannot take this risk. The stranded gas contract mitigates the fiscal risk for the project. However, the contract established between the state and the sponsor group has no influence on the tax policies of outside jurisdictions or the federal government, and the risk of increased taxation by those entities remains an issue.

Fiscal certainty will also enhance the possibility that an expansion of capacity will be required in the first decade of commercial production. The 30-year period is designed to provide a stable regime on oil up until the approximate time when decisions related to the use of potentially available capacity have to be made in order to keep the line full for the remaining contract term. This is the critical period when new gas supplies must be identified and developed in order for the Alaska natural gas pipeline project to succeed. New exploration efforts will typically be for oil as well as gas. In the case of the ANS much of the yet to be discovered gas resources will have condensates associated with the gas. Exploration decisions are typically justified on the basis of the possibility of discovering gas and condensates, or finding oil reservoirs. In order to stimulate new exploration, fiscal stability for oil as well as gas is required. A detailed analysis of international exploration and production contracts indicates that a 30-year fiscal certainty period is a relatively short period for the high cost and high risk areas such as the ANS. The 30-year period is the minimum period required to stimulate significant new exploration efforts.

In addition, the 45-year period of fiscal certainty for gas is intended to provide a long term stable investment climate for the production of known gas resources and the stimulation of exploration and development of gas resources yet to be identified. Additional legislation will be introduced that extends these same assurances of fiscal stability to any party that makes a firm transportation commitment of ANS gas on the pipeline for a defined term. This legislation is intended to spur exploration and discovery of gas fields that require a long term development horizon in order to provide the project with the necessary gas volumes over the life of the infrastructure and, hopefully, to justify subsequent expansions.

6.3.4 Permitting Constraints

Permitting constraints create risk for parties involved in the proposed project, as permitting complications can greatly delay and create added expense for complicated large scale project such as the natural gas pipeline. In light of these potential complications, a consensus package of provisions was passed by the U.S. congress known as the Alaska Natural Gas Pipeline Act of 2004 (ANGPA). The purpose of this act was to aid the development of an Alaska gas pipeline clarifying and expediting the process of developing a new Alaska gas pipeline. ANGPA is described in detail in Section 1.3.3

The provisions established by ANGPA describe FERC’s role in the natural gas pipeline development, allowing FERC to accept and process application for a new project in Alaska under the ANGPA. FERC is responsible for the environmental impact assessment process, and limits were placed on the judicial review, in order to expedite the process. The Alaska gas pipeline is likely to be the only option to market for Alaska’s North Slope resources; therefore Congress gave the FERC the power to order an expansion of the pipeline to satisfy competitive concerns. This provision is the first time FERC has been given the power to order an expansion of any interstate pipeline.

The major provisions of ANGPA include: expedited approval process, prohibition of certain pipeline routes, environmental reviews, federal coordinator, expansion, open season requirements, in-Alaska service, study of alternative means of construction, and loan guarantees.[68] These provisions are focused on expediting the permitting process so that project activities can begin as quickly as is reasonable. For example, ANGPA designates FERC as the lead agency for the NEPA process. The FERC shall prepare a single environmental impact statement, which shall consolidate the environmental reviews of all

[68] As of June 15, 2005, the full text of the ANGPA can be found through the Federal Energy Regulatory Commission Internet Site at http://www.ferc.gov/industries/gas/indus-act/angtp/act.htm#act.

federal agencies considering any aspect of the Alaska natural gas transportation project. The FERC shall (1) not later than one year after it determines that the application for an Alaska natural gas transportation project is complete, issue a draft environmental impact statement; and (2) not later than 180 days after the date of issuance of the draft environmental impact statement, issue a final environmental impact statement, unless FERC for good cause determines that additional time is needed. The impact statement is the driving element in setting the regulatory timeline for FERC. ANGPA requires that the draft and final EIS be completed within 18 months of the filing of a complete certificate application at FERC and that FERC complete its application review and approval process no longer than 2 months after the final EIS. Thus, overall, FERC has 20 months start to finish completing its work on the certificate application. FERC staff would however, work with the project sponsors in a “pre-filing” process before the application is filed in order to assure an expedited processing of the application. In addition, ANGPA gives the FERC power to order expansion of an Alaska gas pipeline after it is built. These powers are carefully spelled out and contain conditions and special procedures that must be satisfied.

There is some degree of regulatory or permitting risk in Canada due to uncertainty over prior rights and proper pipeline authorization procedures. As explained below, TransCanada and the sponsor group have differing views on these issues. TransCanada has rights to build an Alaska gas pipeline in Canada arising from the late 1970’s Northern Pipeline Act, a statutory parallel to ANGTA. The sponsor group believes that these rights do not foreclose a pipeline application pursuant to the well established processes of the National Energy Board and the Canadian Environmental Assessment Act. In the absence of clarity about the interplay of these two processes and rights that result, the project could be delayed. The state believes that a commercial solution among the affected parties is necessary, logical and desirable. The long history of cooperation between the US and Canada and the favorable attitude of both governments towards an Alaska gas pipeline provides assurance that the project will not face unreasonable permitting delay in Canada. The governments of Alberta, British Columbia, and the Yukon Territories also are supportive of an Alaska gas pipeline. See Section 8 for more discussion on Canadian issues.

6.3.5 Environmental Risk

Environmental risk is inherent to a large-scale gas development project. As part-owner of the project the state or its entities could be a potentially responsible party under natural resource damage litigation associated with pollution resulting from negligent actions, accidents, fire, explosions, and similar events although the potential environmental liabilities from a natural gas pipeline event are substantially lower than for crude oil.

The state will address environmental risk through the Right-of-Way Leasing Act (AS 38.35). State resource agencies working in concert with federal resource agencies will, through a public process, identify environmental concerns and develop appropriate mitigation measures for construction, operation and termination activities. The commissioner of natural resources, under AS 38.35.100 must find that the project applicant has the technical and financial capability to take action to the extent reasonably practical to:

(A) prevent any significant adverse environmental impact, including but not limited to erosion of the surface of the land and damage to fish and wildlife and their habitat;

(B) undertake any necessary restoration or revegetation; and

(C) protect the interests of individuals living in the general area of the right-of-way who rely on fish, wildlife, and biotic resources of the area for subsistence purposes.

To make this determination, the commissioner of natural resources will work with state resource agencies to identify environmental concerns and develop appropriate mitigation measures for construction, operation and termination activities. Where existing statutes and regulations do no provide the necessary authority to address a potential concern, the commissioner of natural resources may require protective measures under the right-of-way lease.

The state and federal agencies typically cooperate in large-scale pipeline projects involving both state and federal lands. The agencies share resource information and generally work to address concerns in a cooperative manner. The state anticipates cooperating with FERC in the environmental impact statement (EIS) process which provides another mechanism to also identify potential environmental issues associated with a project. In addition, ANGPA (Section 106 e (1) and (2)) mandates that state and federal agencies cooperate in establishing parallel terms and conditions for the gasline.

State and federal permitting agencies will use rely on the EIS process to evaluate the environmental impacts from the project and to reduce environmental risk. The EIS is an exhaustive environmental analysis consisting of the following steps:

1) Scoping. All the potential issues and potentially impacted resources are identified by surveying agencies and the public.

2) Baseline Data Collection. The existing environmental conditions are evaluated by collecting social and environmental data (for example, existing water quality and fish resources, soil & geotechnical conditions, cultural resources, air quality, etc).

3) Alternatives Analysis. The projected impacts from the proposed project are compared to several alternative projects, one of which will be the “no action alternative” which assumes no gasline is built.

4) Agency Preferred Alternative. The lead agency, with consultation from the cooperating agencies, will determine which of the alternatives (or combination of alternatives) is their preferred alternative, taking into account the projected environmental impacts and the public need for the project.

The EIS process will likely involve multiple rounds of public meetings in communities throughout the potentially affected area, at least three opportunities for public review and comment, and federally mandated government to government consultation with potentially affected native tribes. Once the EIS is complete, the permitting agencies use the results of the EIS to guide their permitting actions, including the development of design and operational stipulations, and abandonment conditions.

The regulatory agencies are mandated to ensure that the gasline will be designed, operated, maintained, and abandoned in a safe and environmentally sound manner consistent with lease and permit requirements, and applicable laws. The agencies have professional staff qualified and trained to review and approve design drawings and plans, conduct inspections and monitoring programs to ensure environmentally sound operation. The agencies also have the authority and experience to mandate prompt and effective response to incidents on the gasline and to assess, contain, correct, and clean up damage, as well as to prevent recurrence.

6.4 Force Majeure

Force majeure is an event that causes an involved party's inability to perform an obligation, or materially adversely affects the party's performance. *Force majeure* events are beyond the party's control. According to the contract, these events include: acts of God, epidemics, fire, hurricanes, floods, earthquakes, etc.; war, riot, civil disturbance, acts of terror or public enemy; unavoidable accidents, equipment failure or breakage; labor disputes or lockouts; and laws of federal, state, Canadian or other governmental entities, or unreasonable delays or failures to act by such entities.

The work commitments are mitigated by certain other conditions as stipulated in Article 35 (*force majeure*) and Canadian regulatory processes or Canadian aboriginal issues. Under Article 35, any party declaring *force majeure* shall provide prompt notification to other parties and shall attempt to alleviate the *force majeure* condition with reasonable diligence to avoid delay. In the event of *force majeure*, certain obligations regarding payments, receipt of hydrocarbons and/or for handling treating and transporting hydrocarbons are suspended. Work suspensions are also allowed during a judicial challenge to the contract and during certain disputes between the parties. The state may not claim *force majeure* due to laws or directives issued by the state or its political subdivisions.

7 Financing the Pipeline

Members of the sponsor group, both jointly and separately, have evaluated the options for commercializing Alaska's gas resources, including GTL, LNG, and a gas pipeline. They have concluded that a gas pipeline project is the most promising option for moving ANS gas to market.

The project, once completed, will provide substantial economic benefits to the state and its citizens (as further described in Section 4 of this document). While project costs are likely to exceed $[20][69] billion, the projected economic benefits to the state outweigh the projected costs and liabilities to be incurred by the state (as discussed below) in connection with the project. This section discusses in general terms the corporate structure for the project, the options currently under consideration by the state and the sponsor group for financing project costs, and the state's options for funding its share of equity contributions for the project. Note that the options set forth in this section are subject to further refinement as the equity arrangements with the sponsor group are finalized, the project is further developed, and discussions with financial institutions, credit rating agencies, the APFC, and the DOE, among others, progress.

7.1 Project Costs

In order to complete the project and realize its economic benefits, the sponsor group and the state collectively will need to spend upwards of $20 billion. A joint producer study completed in 2002 estimated the cost for the construction of the project (gas pipeline, gas treatment plant and other facilities) at $20 billion . The ultimate cost of the project may be substantially higher than $20 billion. More detailed cost estimates will be prepared during the period between the effective date of the sponsor group contract and project sanction.

Table 36 shows the expected schedule for the project capital outlays.

Notwithstanding that project costs will be incurred over a ten-year period, the state and the sponsor group (along with the project lenders) may want to be satisfied that the estimated project costs will be covered by the financing and equity commitments in place at commencement of construction (or, at the latest, first disbursement of the loans). Notwithstanding the foregoing, to the extent the state and the sponsor group believe that the strength of the project would allow for debt financing commitments at a later date to be readily available, they may elect to forego the cost of arranging such commitments at the commencement of construction (or at the first disbursement of the loans).

[69] Please note that the estimated figure for project costs in other sections of this document is $21 billion. We have used $20 billion here, because it is consistent with the estimate in the sponsor group's report and because it makes for more round numbers when calculating the state's share of project costs and project revenues.

Table 36. Project Capital Outlays
(millions of 2005 $)

Year	Gross Costs	Cumulative Costs
Pre-formation Costs	125	125
Year 1	174	299
Year 2	288	587
Year 3	389	976
Year 4	416	1,392
Year 5	3,143	4,534
Year 6	5,671	10,205
Year 7	6,080	16,285
Year 8	3,207	19,492
Year 9	914	20,406
Year 10	594	21,000

7.2 Ownership and Corporate Structure of the Pipeline Entities

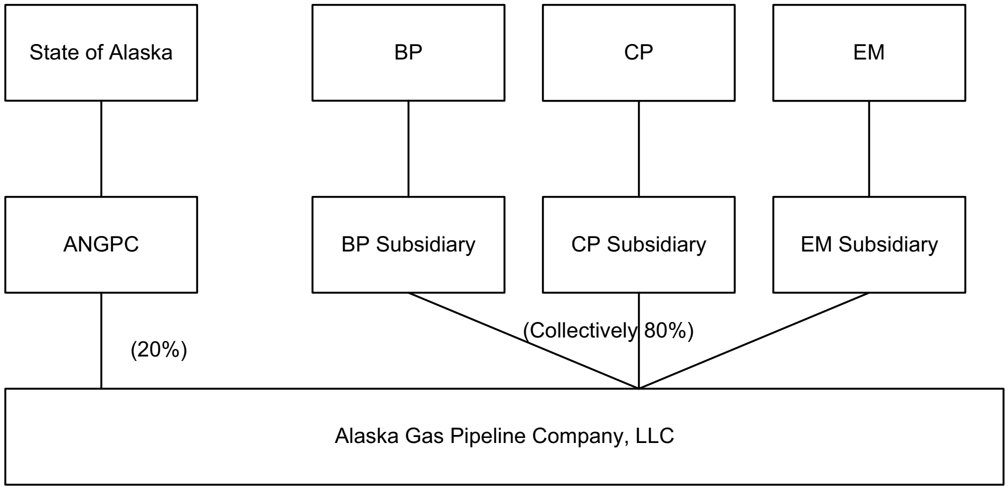
The state has negotiated a 20 percent ownership stake in the project. The state and the sponsor group will undertake the project through one or more project entities which they will form and own (directly or through intermediate entities established by the state or an individual producer, as applicable), including Alaska Gas Pipeline Company, LLC (AGPC), a Delaware limited liability company—the mainline entity that will own the Alaska segment of the pipeline. Although at this time the exact percentage interest of AGPC and the other project entities that will be owned by each producer has not been determined, in total the sponsor group will collectively own 80 percent of the project.

As noted in Figure 47, the state expects to invest in AGPC through the ANGPC, a to-be-formed Alaska public corporation that will directly own a 20 percent stake in AGPC. The state expects to invest a minimum of $800 million as equity capital in ANGPC[70] which will, in turn, use the funds to make equity contributions into AGPC. ANGPC may also establish subsidiaries to own the state's interests in the other portions of the project, such as the Canadian segment, gas treatment plant, feeder lines, and other facilities.[71]

[70] This estimate (and the $3.2 billion estimate regarding the sponsor group's equity investment) is based on ANGPC holding a 20 percent equity interest in AGPC, and is based on the assumptions that there will be $20 billion of total project costs, with 80 percent of total project costs being financed by the members of AGPC (i.e., the ANGPC and the sponsor group or their investment vehicles) (with ANGPC financing 80 percent of its share with debt) or with debt incurred directly by AGPC.

[71] For clarity of presentation, this Fiscal Interest Finding focuses on AGPC as if it were the sole vehicle through which the project is to be implemented, but the overall project implementation (including the financing of project costs and the making of equity contributions for project costs) may be spread among a number of project entities but will ultimately be coordinated by the sponsor group and the state.

Figure 47. Alaska Gas Pipeline Company, LLC Ownership Structure



The sponsor group will collectively invest a minimum of $3.2 billion of equity in AGPC, which may either be invested directly in AGPC or through intermediate entities established by the each member of the sponsor group. In terms of their stock market capitalization, the sponsor group members are among the largest oil and gas companies in the world. They also have very strong credit ratings. Table 37 presents a summary of 2005 year end financial statistics for each company.

Table 37. Producer Selected Financial Statistics (As of December 31, 2005)

	British Petroleum	ConocoPhillips	ExxonMobil
		($Millions)	
Revenues	255,159	183,364	370,680
Net Income	22,632	13,529	36,130
Cash Flow from Operations	25,751	17,628	48,138
Total Shareholders' Equity Capital	79,976	52,731	111,186
Long Term Debt O/S	10,230	10,758	6,220
Total Assets	206,914	106,999	208,335
Standard & Poor's Credit Rating	AA+	A-	AAA
Fitch	AA+	A-	AAA
Moody's	Aa1	A1	Aaa

Note: Financial statistics rely on each firms' Annual Reports and reflect their status as of December 31, 2005.

ANGPC will be a state public corporation similar in structure to other state owned public corporations, such as the Alaska Energy Authority, the Alaska Industrial Development and Export Authority, the Alaska Housing Finance Corporation, the Alaska Municipal Bond Bank, the Alaska Railroad Corporation and the Alaska Student Loan Corporation. ANGPC will have a seven-member Board of Directors—the Commissioner of Revenue, the

Commissioner of Transportation and Public Facilities and five "public" directors appointed by the Governor. The board of Directors will hire an Executive Director, who, with the approval of the board, may hire experienced staff to administer the state's ANGPC investment.

AGPC will be governed by a Management Committee composed of one representative from each member (the members being ANGPC and the sponsor group members or their investment vehicles). The Management Committee will select the managing member to run the day to day business and affairs of AGPC. An affiliate of the managing member will also be the Operator of the pipeline. The AGPC Management Committee will establish a finance committee composed of the sponsor group and ANGPC to develop a detailed finance plan for the project. The management committee will approve this finance plan, which will need to be in place prior to project sanction (i.e., the decision to commence construction), absent a decision by the members to waive such requirement.

7.3 Financing Overview

The state, as a 20 percent owner of the project, will be responsible for funding 20 percent of total project costs ($4 billion based on the current project cost estimate). While the state's funding obligation for the project in a sense must compete with other funding needs of the state and its municipalities, school districts, etc., the administration is confident that it can fund all of its near-term obligations and that the successful completion of the project will provide significant additional cash flow that will expand amounts available to fund the state's long-term funding needs. Moreover, the state anticipates that a majority of its share of project costs will be financed. Such debt financing will most likely be undertaken as a "project financing" in which AGPC borrows up to 80 percent of estimated project costs (including a 10 percent contingency) with only "limited recourse" to the state and the sponsor group members during the construction phase for repayment of the loans and other obligations. Under such project financing structure, after project completion the lenders to AGPC would not have any recourse to the state and the sponsor group; rather the lenders would look solely to AGPC's assets and revenues for repayment of the debt.[72] It is anticipated that the impact on the state's borrowing capacity (and, therefore, its cost of capital and its credit rating) under this financing structure will be considerably less than if the state were borrowing directly 20 percent of project costs.

The ADOR is responsible for the financing of most state projects and will be responsible for negotiating the financing of the state's share of project costs, and has been working with the sponsor group to develop an overall financing plan for the project. ADOR has retained financial advisors consisting of a consortium of investment banks (the Challenger Capital Group Ltd., Credit Suisse and UBS Investment Bank) to assist in ADOR's analysis of the project and the possible methods of funding the state's financial obligations with respect to

[72] While project financing is the state's current preferred finance structure, there are a number of other financing options. The state and the sponsor group are also evaluating "member-level financing" structures, under which ANGPC and perhaps other members of AGPC (the producer investment vehicles) would borrow their respective pro rate shares of debt funds needed by AGPC and contribute to AGPC the proceeds of such financing, either in the form of equity, or possibly through an on-lending of such funds. In such a financing, each member would separately borrow funds, which would be subject to the same or similar completion support requirements (from the state or relevant producer, as applicable) as those required in the project financing.

the project. The financial advisors have expertise in pipeline economics, regulatory matters, and project, government and corporate finance. They have been advising the state on both the overall financing plan for the project and financing issues that are specific to the state. In connection with their advice to the state, the financial advisors have prepared a detailed Finance Plan Report (see Appendix F) which will be updated at least annually and which provides a detailed analysis of the options available to the state for financing its share of the project costs of AGPC with a combination of debt and equity.

The financial advisors are also providing advice on a number of other critical topics, including:

- supplemental financing that may be necessary in the event of cost overruns,
- protecting the state's credit ratings, and
- the optimal structure for overall financing of the project, including the best use of the DOE guarantee (defined below and to be discussed later in this section).

The state also has received advice from Government Finance Associates, the state's financial advisor since 1984.

7.4 Debt Financing of Project Costs

7.4.1 Limited Recourse Project Financing

The state and the sponsor group are exploring a full range of financing structures and options at this time. In evaluating these possible financing structures, the state and the sponsor group will select the structure that most comprehensively satisfies the goals of the state and the sponsor group. The state's finance goals include the following (which the members of the sponsor group share, to varying degrees)[73]:

(1) limit the state's liability (whether such liability results from provision of completion support or otherwise) for the funds borrowed for construction of the project so as to mitigate the impact the project will have on the state's borrowing capacity (and, therefore, its cost of capital and its credit rating);

(2) approach the market in concert with some or all of the sponsor group so as to obtain the best financing terms available;

(3) utilize the federal guarantee instruments (DOE guarantees) available under the ANGPA (if the final terms of such DOE guarantee negotiated with DOE are acceptable) to lower the cost of borrowing and increase the likelihood that the state and the sponsor group can finance 80 percent of estimated project costs; and

[73] While the state and the sponsor group have shared finance goals, they also have individual objectives (such as tax considerations, desire to use available cash on balance sheet to different extents, sensitivity to transaction costs, and varying degrees of tolerance for limitations on project management imposed by lenders) that will need to be considered in connection with finalization of the finance plan. The state and the sponsor group will make the final selection in light of such considerations, and not until the specifics of the project components, including design engineering, procurement and construction costs, are further developed.

(4) obtain the lowest cost of capital and the lowest tariff applicable to the firm transportation contracts over the long run, which might be best achieved by seeking financing with a debt/equity ratio of 80/20.

Based on its analysis of the information currently available to it (including the recommendations of the financial advisors), the state's preferred approach to financing the project at this stage is to undertake a limited recourse project financing with AGPC as the borrower. The state believes that this finance structure would allow it to successfully achieve its main finance objectives described in the preceding paragraph.

While project finance structures differ depending on the specifics of the project to be financed (e.g., industry sector, technology, construction risk, political risks, project economics), there are certain common elements that the state expects (but is not certain, as such terms are subject to negotiation) would be applicable to the financing of this project:

- The lenders will agree to make their loans based on the expected cash flow from operations of AGPC rather than from the creditworthiness of the sponsors of the project. In analyzing such expected cash flow, key issues will include (1) the creditworthiness of AGPC's shippers (affiliates of the state and the sponsor group members)[74], whose "blended credit" underpins the expected revenue stream from the shipping contracts, (2) the strength of the terms of the shipping contracts, and (3) regulatory matters (including permitted recovery of capital costs and rate of return on capital under a FERC-approved tariff for the firm transportation contracts), discussed below.
- After the successful completion of the construction of the project, the lenders will have no recourse for the repayment of the debt to the state or its assets or the sponsor group or their assets.[75] Rather, the lenders will be able to look only to the revenues and, in a default scenario, the real and intangible assets (i.e., the project facilities, bank accounts and contract rights, including the firm transportation contracts) of AGPC, and possibly the state's interest in ANGPC and the sponsor group members' interests in their investment vehicles.
- It is anticipated that AGPC's lenders will not accept completion risk on the project, and will require completion undertakings /guarantees from the state and the sponsor group. Broadly, these documents will provide recourse to the state and the sponsor group (on a several not joint basis) for the repayment of AGPC's debt during the construction phase. In relation to the construction phase, the lenders will typically expect to see (i) a comprehensive guarantee of debt service prior to the completion of the project; (ii) an obligation by the state and the sponsor group to invest their equity in required proportions, either up-front, *pro*

[74] The state, either directly or through a state entity to be established, will form a gas marketing arm that will be a shipper and enter into a firm transportation contract with AGPC, LLC with a FERC-regulated tariff. See further information on the state's gas marketing plans at Section 8.

[75] Another possible structure is for AGPC, LLC to obtain interim construction debt (supported by the state and the sponsor group) that will be refinanced at project completion with long-term debt that is non-recourse to the direct and indirect owners of AGPC, LLC. AGPC, LLC and its members will evaluate market conditions and available financing options in making a final determination as to whether long-term or construction financing will be selected.

rata with the senior debt or (less commonly) at least by the completion date (i.e. so at the completion the debt to equity ratio is at the agreed level); and (iii) a commitment to fund cost overruns.[76] The state and the sponsor group will seek to mitigate such risks by, among other things, agreeing to fixed price, turnkey engineering, procurement and construction contracts, sound project management with the sponsor group, and by arranging (either at construction commencement or at a later date if they determine that cost overruns are likely to be incurred) supplemental financing for a portion of overrun costs.

If the state and the sponsor group achieve a financing with the project finance characteristics described in the preceding paragraph, then the impact on the state's borrowing capacity (and, therefore, its cost of capital and its credit rating) as a result of its participation in the project will be significantly less than if the state were the borrower of 20 percent of project costs. This is expected to be the case even during the construction phase, when the state bears contingent risk for repayment of a *pro rata* portion of AGPC's debt; the credit rating agencies have traditionally viewed a call on completion support provided by project sponsors as a fairly remote risk and have evaluated the impacts on the credit ratings of entities providing such support accordingly. The state's total outstanding debt as of June 30, 2005 was $584.2 million. The state's general obligation debt is currently rated by Standard & Poor's, Moody's and Fitch as an AA credit. If the state issued debt that might require it be repaid from resources other than from project revenues (such as requiring a replenishment of a reserve fund from state appropriations), the rating agencies would evaluate the likelihood and timing of the obligation and the amount of state resources and other obligations to determine whether the obligation was so significant to warrant a downgrade of the state's credit rating. It is estimated that a full letter grade downgrade from AA to A of the state's credit rating would increase the state's cost of borrowing by approximately 0.05 percent to 0.50 percent depending on the market environment. A downgrade of the state's credit rating may also result in a rating downgrade for other Alaska state agencies and most municipalities, resulting in higher borrowing costs for these political subdivisions as well.

Members of the sponsor group have extensive experience in complex financings for major oil and gas projects. The sponsor group members are considered "pros" by the financial markets and credit rating agencies in closing large scale financings. If the state and the sponsor group pursue a project financing, the state will have the benefit of the sponsor group members' experience and market clout to negotiate favorable pricing and other terms.

7.4.2 Member Level Financing

The LLC agreement for AGPC provides the members with the flexibility to select (subject to voting requirements) whatever financing option they deem most advantageous. Based on the discussions to date between the sponsor group and the state on financing options, the financial advisors believe that the sponsor group are likely to propose a limited recourse

[76] The state and the sponsor group will work with the financial advisors and counsel to carefully define the scope of these liabilities and the mechanics and terms under which they are released from these obligations.

member-level financing structure (as an alternative to a limited recourse project financing with AGPC as the borrower) that looks like the following:[77]

- Each member (or a finance affiliate of such member) (e.g., ANGPC) would borrow its pro rata share of the financing needed by AGPC and such member would be severally obligated to repay its lenders.
- Each member would contribute to AGPC the proceeds of such member's financing, either in the form of equity, or through an on-lending of the funds or a combination thereof.[78]
- Each member would cause AGPC to assign to such member's lenders its rights under the firm transportation contract between AGPC and such member's shipper affiliate.
- The creditworthy sponsor affiliated with each member (i.e., the state and the sponsor group members) would provide completion support to such member's lenders with respect to its member's debt obligations.
- Each member's financing would be arranged in a coordinated fashion with the financing of the other members.

In the event the members elect to pursue a member-level financing, one option available to the state for financing its 20 percent share of project costs would be for ANGPC to issue revenue bonds to debt finance a significant portion of its share of such project costs. The dividends paid to ANGPC as a 20 percent investor in AGPC would be the primary source of funds for payment of these bonds and the bondholders would ordinarily seek a pledge and/or assignment of the following collateral:

- dividends to ANGPC from AGPC;
- ANGPC's 20 percent membership interest in AGPC; and
- the firm transportation contracts between the state's gas marketing entity and AGPC.

While it is worth noting that both member-level financing and traditional project financing with AGPC as the borrower could be achieved on a limited recourse basis, and that the project's economics will still be the primary basis for the evaluation of credit, there are some important differences between these financing structures. Certain of these differences, which are explained more fully in the Finance Plan Report, may affect the state negatively in a variety of ways, including a decrease in the state's borrowing capacity, which could result in the state having an increased cost of capital and a lower credit rating. In addition, there is some uncertainty as to whether the members could take advantage of DOE guarantees

[77] Please note that there are many different types of member-level financing structures, and we are presenting a description of a member-level financing in this document common to many structures only as an illustrative example to provide a better understanding of the differences between a project financing with AGPC, LLC as a borrower and a member-level financing. Note that a member-level financing would not necessarily include all members, some of whom may elect to contribute equity. In such a case, there are additional complications with respect to the security package (non-participating members may not want firm transportation contracts, which are assets of AGPC, LLC, pledged as collateral for other member's debts). Moreover, as fewer members of the sponsor group participate in the debt financing of the project, ANGPC's ability to leverage its investment and otherwise achieve favorable terms may be diminished.

[78] Whether or not the funds are contributed as equity to AGPC, LLC or on-lent depends on whether the other members also adopt member-level financing.

(which, as discussed below in Section 7.4.3, could provide a significant benefit to the state) under a member-level financing.

7.4.3 Federal Loan Guarantee

While lenders' analysis of the proposed project financing would ordinarily be keyed solely to the project's economics (including shipper credit strength), and would be priced accordingly, a major credit enhancement available to the state and the sponsor group is to utilize the DOE guarantees and have the Federal Government guarantee AGPC's debt. In order to encourage development of the project, the U.S. Congress passed The Alaska Natural Gas Pipeline Act of 2004 on October 13, 2004. The Alaska Natural Gas Pipeline Act makes DOE guarantees available for up to $18 billion or 80 percent of the cost of the project, whichever is less, and delegates administration of the Federal Loan Guarantee program to DOE. The specifics of the program are still being developed by DOE. Note that provision of the DOE guarantees would not relieve AGPC of its responsibility to pay all interest and principal on borrowed funds. However, the DOE guarantees will provide AGPC's lenders or the buyers of its bonds with the comfort that the Federal Government would make such lenders or bondholders whole if AGPC failed to meet its payment obligations to them. Should this guarantee be called upon, the Federal Government will then require the borrower to make good on its borrowing commitment. The DOE guarantee program is also available to help finance the Canadian portion of the project.

The terms of the DOE guarantees have yet to be discussed and negotiated by the state, the sponsor group and DOE. However, both the state and the sponsor group see potential value in utilizing the DOE guarantees in some fashion, and intend to take full advantage of the DOE guarantees if they are available on acceptable terms and conditions. At this juncture, the state and the sponsor group are uncertain whether the DOE guarantees would be utilized in a limited recourse financing for only the first $18 billion of debt incurred or sold to construct the project or instead reserved to cover debt which may need to be incurred or sold to cover cost overruns (or in another manner that may be more cost-efficient for the project and state). In any event, application of the DOE guarantees to AGPC's debt will probably lower the cost of borrowing in respect of such debt by between approximately 0.90 percent and 1.10 percent.

7.5 Financing State Equity Contribution

There are two primary options for financing the state's equity investment[79] of approximately $800 million in the project currently under consideration: (i) direct appropriation of funds and (ii) revenue bonds. As discussed more fully in following sections, the state is also considering whether the Permanent Fund should be given the option to have a role as an equity participant in the project.

[79] We have assumed for purposes of this section that 80 percent of project costs will be funded by project financing. A minimum of $800 million will therefore need to be separately raised by the state. The state and the financial advisors are also considering the extent to which the state should also make provision for cost overruns; it may be committed to fund its *pro rata* share of cost overruns pursuant to its shareholder arrangements with the sponsor group and under the financing documents entered into in connection with the project financing.

7.5.1 Direct Appropriation

Direct appropriation, whereby the legislature would appropriate the funds and direct that they be invested in ANGPC, is the simplest and most straight forward option for financing the state's equity contribution. There is ample precedent for this approach given that direct appropriation is the manner in which most state-owned corporations have been capitalized. Direct appropriation also provides the state with the maximum flexibility to deal with cost overruns.[80] Prior legislative appropriations that capitalized the three largest state corporations are shown in Table 38.

Table 38. Previously Funded State-Owned Corporations

Corporation	Amount Funds
Alaska Industrial Development	$325,000,000
Alaska Housing Finance Corporation	1,070,000,000
Alaska Student Loan Corporation	307,000,000
Total	$1,702,000,000

Though the financial advisors have discussed the possibility of funding the state's equity contribution in part with additional debt (e.g., revenue bonds), for the reasons set forth in this section, direct appropriation is the state's preferred alternative for funding its equity requirements.

7.5.2 Revenue Bonds

ANGPC could issue revenue bonds to be repaid out of the proceeds of ANGPC's 20 percent share of the distributions from AGPC, which bonds might need to be further enhanced by including the moral obligation pledge of the state to replenish a debt service reserve fund for the bonds. This reserve fund is generally established as the maximum amount of debt service required in any year. If the reserve fund is drawn upon to pay debt service so that the balance falls below its required level, the legislature may, but is not legally required to, appropriate funds sufficient to restore the reserve fund to its required level. The most likely reason that a reserve fund would be drawn upon would be if ANGPC's share of revenues from the project were insufficient to meet a given debt service payment and the reserve fund had to be used to make the payment. There are also state credit rating implications associated with any call upon the state moral obligation pledge. Specifically, any debt for which the moral obligation pledge of the state is used would be included by the credit rating agencies in the net tax-supported debt of the state. The authority of ANGPC to issue moral obligation bonds will need to be expressly authorized by the legislature in the authorizing legislation for ANGPC adopted by the legislature.

7.6 Preliminary Conclusion Regarding Financing of Project Costs

In light of the analysis set forth above and the state's finance goals set forth in Section 7.4.1, at this time, the state has concluded that its preferred method for financing project costs is (i)

[80] As noted above, the lenders will need comfort that the state is committed to fund at least $800 million.

to pursue debt financing that uses a traditional project financing structure with AGPC as the borrower and that takes advantage of the DOE guarantees and (ii) to fund its equity contributions with direct appropriations (i.e., cash). As noted above, this conclusion is subject to change as the equity arrangements with the sponsor group are finalized, the project is further developed, and discussions with financial institutions, credit rating agencies, the APFC, and the DOE, among others, progress.

7.7 Possible Role for the Alaska Permanent Fund Corporation

The administration is currently discussing with the APFC whether there is a role for the Permanent Fund in the project that would be consistent with the state's goals and would meet the APFC's own mandate. The possibilities for APFC involvement include:

(1) making an equity investment in either ANGPC or AGPC, and/or,

(2) being a lender to ANGPC.

7.7.1 Investment Analysis

To the extent that such an investment is consistent with the Permanent Fund's mission of maximizing "the value of Alaska's Permanent Fund through prudent long-term investment and protection of principal to produce income to benefit all generations of Alaskans,"[81] the Permanent Fund could elect to participate in the project by investing in AGPC or ANGPC.[82] The state and the participants expect the project to yield a competitive rate of return on equity, with initial return on investment in 2016. Therefore the Administration does not expect the Permanent Fund Corporation to evaluate the project as if it were an economic development project.[83] The Permanent Fund Corporation is not prohibited from investing in the project and the Fund's involvement will be viewed and analyzed by its board of trustees only from the perspective of a prudent financial investment.

The Permanent Fund's principal is invested for the long term in diversified asset classes such as bonds, stocks, real estate and private equity. The APFC's Board of Trustees is the fiduciary for all Permanent Fund investments and, with assistance of its staff and others, directs the allocation of funds to asset classes utilizing modern investment portfolio theory. If the Permanent Fund Corporation were to invest in the project it would expect to be compensated with a risk adjusted rate of return competitive with similar Permanent Fund holdings as well as with other opportunities in the marketplace. The Permanent Fund Corporation is selecting a consultant with expertise in gas pipelines and pipeline financing to assist with its "due diligence" relative to a potential investment in the project.

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[81] Alaska Permanent Fund Corporation. (2001). *An Alaskan's Guide to the Permanent Fund*, page 45. Juneau, Alaska: Alaska Permanent Fund Corporation.

[82] The investment analysis will differ depending on what role (if any) the Permanent Fund Corporation takes. For example, as a lender to the project, the Permanent Fund Corporation would likely earn a lower return on investment (in the form of interest paid on its loan) than an equity investment, but it would also have a lower level of risk than an equity investment in a number of respects (including priority of payment for scheduled payments of interest and principal over equity distributions).

[83] Historically the Permanent Fund Corporation has not invested in economic development projects in Alaska because other state entities, such as the Alaska Industrial Development and Export Authority, Alaska Housing Finance Corporation and the Alaska Energy Authority have been assigned these missions

7.7.2 Potential Sources of Funds for Investment

The Permanent Fund is divided by the constitution into two parts—1) the reserved assets which include the principal and unrealized earnings, known as the "Principal", and 2) the unreserved assets or realized earnings, known as the "Realized Earnings Account." The trustees have the ability to invest both the principal and the earnings of the Fund in investments that meet the Prudent Investor threshold. The legislature may appropriate only from the realized earnings account ($3.57 billion as of March 31, 2006). The principal balance of the Permanent Fund ($30.26 billion as of March 31, 2006) is not subject to appropriation by the legislature under the state constitution.

Presently the legislature has statutorily directed that the Realized Earnings Account be used for dividends for Alaskans and to protect the fund principal from inflation. Table 39 displays the fiscal year end value of the realized earning account and fund principal for 2001-2005 and projected for 2006-2011.

Table 39. Permanent Fund Corporation Realized Earnings Account and Principal

		Realized Earnings Account	Principal
Year	Type	($ in millions)	
2001	Realized	2,384	22,431
2002	Realized	1,136	22,389
2003	Realized	100	24,094
2004	Realized	859	26,541
2005	Realized	1,440	28,522
2006	Projected	2,323	31,715
2007	Projected	2,500	31,400
2008	Projected	3,100	32,300
2009	Projected	3,700	33,700
2010	Projected	4,200	34,500
2011	Projected	4,700	36,600

7.7.3 Corollary Benefits to the Fund

Whether the Fund's trustees decide to invest in the project or not, there will also be additional royalties that would flow to the Permanent Fund during the project operations. According to projections presented in Section 4, by the end of the 10th year of operations, the accumulated revenues to the Permanent Fund could total about $1.2 billion at $3.5 per mmBtu gas price, $2.9 billion at $5.50 per mmBtu gas price, or $5.3 billion at $8.50 per mmBtu gas price.

7.8 Regulation

The project will be subject to regulation by FERC and its Canadian counterpart NEB (FERC and NEB are jointly referred to as the "regulators "). The regulatory process will impact the financing of the project in a number of ways including the following:

- The open season process will create a competitive bidding mechanism for pipeline capacity that will result in long-term "firm delivery" shipping contracts that will serve as the revenue source for the project (including revenue required for payment of operating expenses, payment of debt service, and return on equity).
- The regulators will each issue certificates authorizing project construction within their respective jurisdictions only if they are satisfied that the financing plan for the project is realistic and will result in just and reasonable tariffs; and
- The regulators will approve the initial tariff and will periodically review the reasonableness of the tariff given the cost of capital used to construct the project, risks, and operating expenses for the project. Shippers who have not signed long-term shipping contracts remain free to challenge the reasonableness of previously approved tariffs. The regulators will not alter those tariffs, however, unless a showing is made that they are no longer just and reasonable.

8 Next Steps

The section describes the next steps to be taken to move the pipeline forward. Not all the steps are sequential because several of the steps need to overlap in their timing sequence. This section begins with a discussion of the amendments needed so that the contract will conform to the enabling legislation set out in the Stranded Gas Development Act (SGDA) followed by a discussion of the other steps in the conceptual timeline. These steps include approval and execution of the contract, creation of the project legal entities and those for state participation, front end engineering and design, the open season process, the environmental and regulatory approval process for the U.S. and Canadian portions of the project, Canadian right of way issues, project sanction, and ultimately construction and commencement of operations.

8.1 Proposed Amendments to the SGDA

The SGDA was originally enacted in 1998. As originally enacted, the SGDA was focused primarily on terms that would grant project sponsors as much fiscal certainty as permitted by law. Since then, the competitive framework has shifted significantly for gas. It was also determined that the state would become a partner in the project and that terms must be negotiated to define that business relationship. In recognition of these changes, the parties negotiated terms knowing that conforming amendments would be needed so that the contract will be authorized by the enabling legislation set out in the SGDA. The findings and determinations of the commissioner that the contract furthers the purposes of the SGDA assume the enactment of these conforming amendments. Set out below is a summary of the major provisions of the bill necessary to confirm the authority of the state to enter into this contract:

Fiscal Certainty on Oil. The bill would provide authority for contract terms giving the sponsors fiscal certainty for their exposure to taxation on oil produced in the state. Existing law allows only terms that give fiscal certainty on stranded gas. As explained above (See Section 4), there is a close connection between the production of oil and gas. For this reason, the state concluded that it was reasonable to give fiscal certainty on oil as well as gas produced in the state in connection with this contract. The producers feared that the economics of the project could be in jeopardy because certainty granted on gas could be taken away by increasing taxes on oil production. At the same time, the state desired a tax structure that would encourage exploration for new gas reserves so that the gas line would run at capacity for the term of certainty granted for gas. Based on the completion of negotiations, the bill may allow terms in a contract that would provide certainty as to the amount of corporate income tax, production, and property tax owed to the state for the production of oil.

Contract Term. The bill would permit the contract to extend for a term of 45 years from the effective date. This time period is calculated to cover a ten year period during which the project is developed to the commencement of commercial operations and then for a 35-year period thereafter (See Section 4.7.2). The bill would delete a provision which would have the contract expire when all of the stranded gas is developed.

State Equity Ownership. The bill would provide authority for the state to take an ownership interest in the project (See Section 3.1). During negotiations it was determined that the state would take an ownership interest approximating the amount of gas that it expects to ship on the mainline.

Tax Gas. In order to align the state's equity ownership of 20 percent of the gas line to match the share of gas that it expects to ship through the gas line, it was determined to give the state the option to receive payment of the production tax in the form of gas rather than money. Having the ownership interest match the throughput of gas is an important part of the state's plan to encourage development of the project through the sharing of risk among the sponsors and the state (See Section 4.7.1).

Acquisition of Mainline Capacity for the State. The bill would authorize terms in the contract under which the sponsors would act on behalf of the state to obtain capacity on the mainline to transport state gas (See Section 4.5.3).

Suspension of Sponsor Obligations. The bill would authorize terms that permit suspension of certain producer work commitments and other contract obligations during disputes over those obligations and while lawsuits challenging the validity of the contract are pending (See Section 4.7.6).

Conflicts with Existing Leases, Unit agreements and Royalty Settlement Agreements. The bill would include provisions to allow broader powers to adopt terms resolving conflicts between the terms of the contract and provisions in existing oil and gas leases and unit agreements Article 41 of the contract; see Appendix E). Under this provision, the terms of the contract would prevail over contrary provisions in state leases or unit agreements.

Recoupment and Offset. The bill would authorize terms in the contract which establish a method for settling unpaid payment obligations owed among the sponsors and the state. Under the contract, the state may owe the sponsors for various obligations arising out of their business relationships (See Section 3.2.). The sponsors will also owe the state for certain obligations to pay obligations under state law, lease agreements and royalty settlements. The contract would permit a party to net out certain of these obligations and only pay the difference.

Payment of Interest on Unpaid Obligations. The bill would authorize the state to pay interest on unpaid payment obligations owed to the sponsors (See Section 3.2).

Indemnity and Hold Harmless. The bill would authorize terms in which the state agrees to keep a party from being financially harmed from certain designated risks. The source of money to cover this potential liability would be the recoupment provisions. If that source is not sufficient, the legislature will be requested to enact appropriations to cover the unfunded liability (Section 3.2).

RCA Jurisdiction. The bill would authorize terms relating to the state's position on the Regulatory Commission of Alaska over the project (See Section 4.7).

State Acquisition of Capacity. The bill would authorize contract terms permitting the state to obtain pipeline capacity to transport state gas (See Section 4.5).

Limitation of Damages. The bill would authorize contract terms in which the parties may limit the extent of damages that can be claimed (Article 37; see Appendix E).

Reserves Tax. The bill would authorize contract terms that permit the state to give fiscal certainty regarding a tax on reserves or resources (See Section 4.7).

Arbitration. The bill would allow the contract to contain terms which permit the parties to agree to an arbitration process that is different from the state uniform arbitration Act (See Section 4.7).

Confidentiality of Information. The bill would authorize contract terms relating to the confidentiality of information supplied by the producers under the contract. It is expected that the sponsors would provide proprietary information to the state while performing obligations under the contract. It is also expected that, under the fiscal terms, the sponsors and the state would generate information that would be the equivalent of taxpayer information. However, because the sponsors would make payments in lieu of taxes, this information would no longer qualify as taxpayer information under the Revenue and Taxation Code. This contract term would give the sponsors' information the same protection as taxpayer information (See Section 29; Appendix E).

Credit for certain facilities. The bill would authorize a contract term that extends a credit against certain payments in lieu of taxes for certain capital expenditures (See Section 6.2).

Collateral Agreements. The bill would authorize state officials to make other agreements necessary to establish the public and private entities that would own and operate parts of the project or exercise marketing functions. These additional or collateral agreements would not be subject to further legislative action before they become effective.

8.2 Review and Execution of the Contract

Under the SGDA, once the Commissioner of Revenue (commissioner) develops a proposed contract, he/she must make preliminary findings and determine whether the proposed contract terms are in the long-term fiscal interests of the state and the purposes of the SGDA. A proposed contract that includes these terms is submitted to the governor. The proposed contract and preliminary interest findings also go out for public review. Copies of the proposed contract, the commissioner's preliminary findings and determination and, to the extent the information that is not required to be kept confidential, all the supporting financial, technical and market data are made available to the public, the presiding officer of each house of the legislature, the chairs of the finance and resources committees of the legislature, and the chairs of the special committees on oil and gas if any. The commissioner also offers to appear before the Legislative Budget and Audit Committee to review the preliminary findings and determination, the proposed contract, and the supporting financial, technical, and market data.

A period of at least 30 days is established for the public and members of the legislature to comment on the proposed contract and the preliminary findings and determination. A summary of the public comments is prepared by the commissioner within 30 days after the close of the public comment period. If needed, after consultation with the commissioner of natural resources and the pertinent municipal advisory group, a list of proposed amendments is prepared. Then a final findings and determination is made about whether the proposed contract and any amendments meet the requirements and purposes of the SGDA.

If the commissioner determines that the contract is in the long-term fiscal interests of the state, the commissioner submits the contract to the governor. Then the governor may transmit the contract to the legislature with a request for authorization to execute the contract. The contract is not binding or enforceable against the state or other parties unless the governor is authorized by the legislature to execute the contract. The state and the other parties to the contract may execute the contract within 60 days after the effective date of the law authorizing the contact.

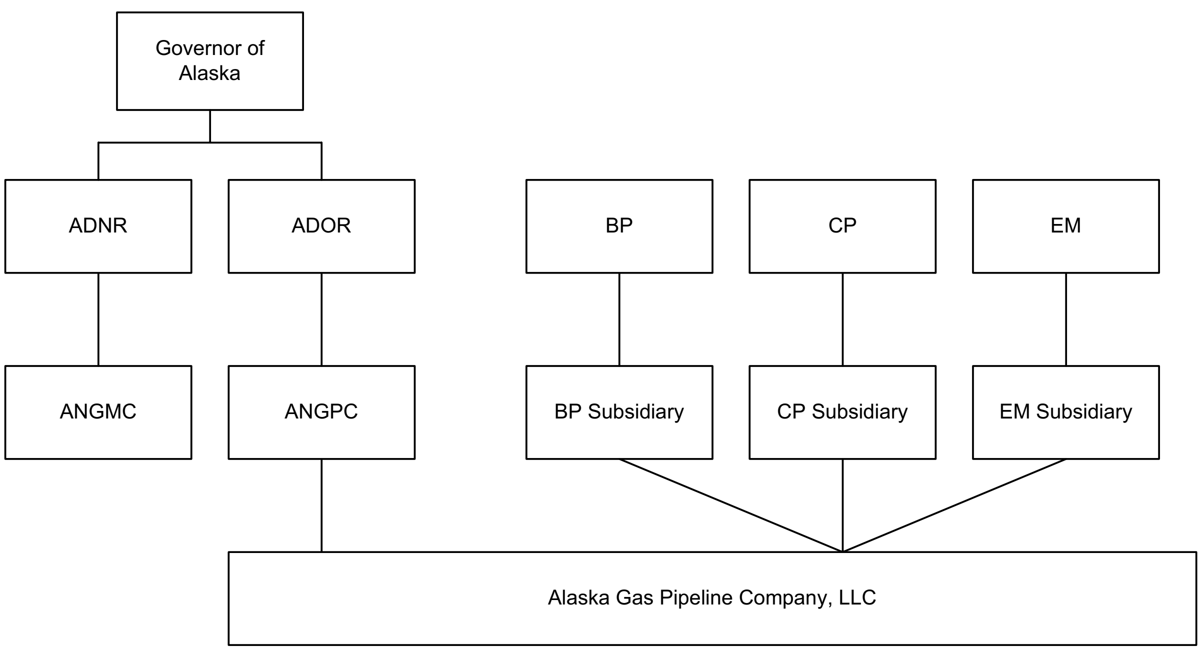
8.3 Establishment of the Entities

The project will require creation of numerous public and private entities in both the U.S. and in Canada. This section describes some of these entities.

8.3.1 Project Ownership Entities

The basic ownership structure for the project is presented in Figure 48. In addition to the LLC that will own the mainline, the contract envisions that other entities would be formed to own other portions of the project, such as the GTP, the gas transmission lines, and the Canadian portion of the project. The following subsections provide additional information about the state entities that will have ownership positions, and the marketing organization.

Figure 48. Conceptual Project Ownership Structure



Note: The Alaska Constitution requires that public corporations be established within a principal department for administrative purposes only. The public corporations would be independent entities according to law with a separate legal existence from the state.

8.3.1.1 Alaska Natural Gas Pipeline Corporation

The state will create several legal entities to own, manage, transport, and market Alaska's natural gas and/or to hold the state's equity interests in other project entities. The state currently plans to establish the ANGPC, an Alaska public corporation, wholly owned by the State of Alaska. The ANGPC will serve as the state's member and an active participant in another entity to be created, the Alaska Gas Pipeline Company, LLC (AGPC). The AGPC is the project entity that will build, own, and operate the Alaska portion of the mainline. The LLC agreement for the AGPC, is currently under negotiation by the parties. Structuring of other project entities has not been finalized, but it is anticipated that ANGPC will likely own, either directly or through subsidiary entities, interests in other project entities that will build and operate the Canadian portions of the pipeline, the Gas Treatment Plant, and any other components of the project. The state may also form a separate entity to own the state's royalty and tax gas and to be responsible for sales and marketing of the state's gas.

The State of Alaska Legislature will need to enact enabling legislation to establish ANGPC as a public corporation independent of the state. ANGPC would then acquire the state's ownership position in the pipeline project. Proposed draft legislation for establishment of ANGPC is contained in Appendix K. ANGPC would be governed by a seven-member board consisting of the Commissioner of Revenue, the Commissioner of Transportation and Public Facilities, and five public members appointed by the Governor.

ANGPC will be authorized to enter into contracts and to acquire ownership in the pipeline and will be granted broad powers with respect to legal and financial matters related to the project. The corporation will have the authority to borrow money and issue bonds, payable from such a special fund or funds as may be established. The bonds may be backed by incoming receipts or other moneys derived from the gas pipeline project and secured by pledging ANGPC's interest in AGPC.

ANGPC will have the authority to establish separate, wholly-owned subsidiary entities to own, finance, and operate any portion of the pipeline. For example, a separate ownership entity could be established to own the state's equity interests in portions of the Canadian project or the NGL plant.

The draft legislation in Appendix K establishes an Alaska Natural Gas Pipeline Construction Loan Fund in ADOR to assist in the acquisition and financing of the state's ownership interest in the pipeline. The Commissioner of Revenue is authorized to lend money from this fund to finance the ANGPC and its subsidiary entities.

The ANGPC draft legislation in Appendix K provides for the establishment of a pipeline project cash reserve fund. The cash reserve fund would consist of appropriations made by the legislature in money or other assets transferred to the fund by the corporation. Deposits in the fund may be pledged for the repayment of bonds, to secure a line of credit, or otherwise meet capital or other financial requirements of the corporation. Money in the fund must be invested in the manner provided for in the draft legislation.

As envisioned, ANGPC would provide quarterly financial statements to the legislative budget and audit committee within 60 days after the end of each fiscal quarter. ANGPC would also provide annual, audited financial statements to the legislative budget and audit committee within 150 days after the end of each fiscal year.

The legislative budget and audit committee may also provide for an internal audit of ANGPC's books, records, and accounts. The legislative budget and audit committee may also evaluate the annual operational and performance of ANGPC, its operations, and its budget effectiveness. This condition also applies to any wholly-owned subsidiary of ANGPC; however, the legislative budget and audit committee shall not have the authority to audit operations or performance of any entity not wholly owned by the corporation.

By September 30 of each year, ANGPC's board of directors (board) shall publish a report of the corporation for distribution to the governor and the public. The board shall be responsible for notifying the legislature that the report is available. The report must include financial statements audited by independent outside auditors. The statement must include the amount of money received by ANGPC from its operations during the period covered by the audit.

8.3.1.2 Alaska Gas Pipeline Company, LLC

The core terms of the LLC agreement of Alaska Gas Pipeline Company (AGPC), currently under negotiation, are described below. The AGPC will be a limited liability company with four members formed under the laws of Delaware. These four members or entities will be directly or indirectly owned by the three members of the producers group and the ANGPC—the state-owned entity discussed above. Figure 48 depicts the ownership structure of AGPC.

The initial capital contributions would be made by members of AGPC as agreed in the LLC Agreement. Subsequent capital contributions will be made in accordance with each member's pro rata interest in AGPC.

AGPC will be managed by a management committee comprised of one representative from each member of the AGPC. Voting will be weighted by each member's pro rata ownership interest. The management committee will make all major decisions and will appoint, oversee, and direct the managing member selected to conduct the day-to-day affairs of the project entity. The management committee will also select an operator to construct and operate the mainline LLC pursuant to the terms of an operating and services agreement entered into with AGPC. The operator and the managing member will be from the same corporate family to ensure efficiency and promote information flow.

To the fullest extent permitted by law, all fiduciary duties owed by members to one another or to AGPC as an entity will be waived. The reason for this waiver is to create a structure as close as possible to that of a joint venture as permitted by law to preclude members from suing one another over voting decisions.

As noted above, voting is weighted by pro rata ownership interest, so the state is expected to have a voting percentage of 20 percent. The voting procedure in the LLC agreement is under deliberation by the parties. The state will have a vote in all matters except as noted below. Also, in some circumstances, such as potential default, conflict of interest, and certain tax matters, a member may be excluded from a specific vote. In this situation, the other members' voting percentages will be adjusted to account for the excluded member's voting interest.

The majority of member breaches under the LLC agreement would be adjudicated in the courts to determine contractual damages or other appropriate remedies under law, but the LLC agreement identifies certain defaults for which specified remedies will be available.

These defaults include failure to make scheduled capital contributions, an unauthorized transfer of an ownership interest, misrepresentation, and certain material changes to a member's governance documents, including the enabling legislation authorizing the formation of ANGPC.

As part of its normal course of business, AGPC shall maintain books and records. AGPC's accounts shall be maintained on an accrual basis in accordance with required accounting practices. In addition, AGPC would keep a separate set of books and records consistent with the provisions and accounts as set forth in the FERC uniform system of accounts as noted at 18 CFR part 201.

Quarterly financial statements shall be prepared in compliance with requirements of the Security and Exchange Commission's (SEC) regulations as if it were a registrant under the Securities Exchange Act of 1034. All financial statements must be reviewed by independent accountants using standards and procedures in compliance with applicable government regulations and generally accepted auditing standards.

Responsibilities of the managing member include preparation and submittal of the application for the FERC certificate, along with other state and federal applications necessary for the construction and operation of the pipeline. The managing member will keep other members informed of the status of the application along with design, tariff, and other material issues. After a maximum of 60 days of FERC review, the managing member would certify that the application has been revised in response to comments by the other members.

Transfers of ownership interests would be subject to certain customary restrictions. Also, certain transfers of ownership interests would be prohibited if such transfers would result in a member retaining less than five percent of the interests in AGPC, or transferring less than all of a member's interest if they hold less than 10 percent of the interests in AGPC. Existing members also have preferential rights to purchase interests on the same terms and conditions as might be offered to third parties.

The LLC agreement also includes provisions regarding withdrawal of a member or a dissolution or liquidation of the entity and other typical contractual provisions for a limited liability company. As stated earlier, other project entities are expected to have similar terms, with the details modified to meet the specific needs of the project component.

8.3.1.3 Other Project Entities

The state and the producers together will need to create other project entities to construct and operate the various components of the project. The state, the producers, and each of these project entities will also need to enter into appropriate arrangements to insure that the planning, development, construction, and operation of all aspects of the project is coordinated among the project entities. The state would, or in some cases have an option to, participate as a 20-percent owner in each project entity created[84]. The state is required to maintain ownership interests in project entities that own the gas transmission lines, gas treatment plant, mainline, and the Alaska to Alberta project until the state executes a binding legal agreement to reserve capacity for all its expected shipments of royalty and tax gas. If

[84] As explained above, in gas transmission lines and certain other portions of the project, the state ownership share is proportionate to its estimated share of the total gas throughput on these lines.

the state takes an initial ownership interest in the Alberta to Lower 48 Project, it will also be obligated to retain an ownership position in that portion of the project until completion of the initial open season.

Once binding agreements are in place, the state may withdraw from a component of the project or assign its interest in the project entity as permitted under the applicable provisions of the project entity's governance agreement. The LLC agreement negotiated for the Alaska Gas Pipeline Company is expected to serve as the template for the governance agreements of other project entities. Once negotiations of the LLC agreement are complete, the mainline LLC agreement will be modified to meet the requirements of the other project entities. Because of differences in purpose and, in some cases, governing law, the intent is that the mainline LLC agreement would provide core terms that can be reflected but modified as necessary in subsequent agreements.

8.3.2 Alaska Natural Gas Marketing Company

Once the gas contract has been approved, the state plans to establish within a year the ANGMC, or such other entity or structure that the tax and policy review indicates is more beneficial to the state. The ANGMC as currently envisioned would be governed by a board of directors having a similar degree of independence as the ANGPC board.

The goal of ANGMC would be to maximize the value of the state's royalty gas and tax gas and minimize the risks to the state. The purpose is to make forward looking decisions related to the disposition of the state's physical natural gas. ANGMC will serve as the vehicle through which the state can contract with energy industry participants in the same fashion as the state's market competitors.

The ANGMC will make use of a number of sources of expertise, including consultants from the energy finance sector, experts within the domestic and foreign gas markets, and legal experts within both the U.S. and Canada. The overall corporate framework may be very similar to the APFC, in that the APFC also seeks to balance the return and the risk of the Permanent Fund in an optimal manner. The ANGMC would study the experience of the U.S. Minerals Management Service and other government-owned and private marketing organizations in taking delivery of, and marketing the gas.

ANGMC would review, in the year after its creation, a number of management and marketing options as described below. The ANGMC will need to prepare for participation in the various open seasons. The first open season is expected to take place within two years after the effective date of the contract (See the timeline in Table 40).

Also ANGMC will assist in the development of a strategy and plan for possible participation in the NGL plant, if one is built, and the Alberta to lower 48 project. These are potentially two important aspects of the total project as contemplated in Article 4 of the contract and the state needs to be prepared to be an effective participant.

It should be realized that decisions that are made early in the time line may change due to subsequent market shifts. A number of options (See Section 8.3.) will be examined and the relative value and corresponding risk of each will be weighed appropriately. In the long run, a balanced approach will likely involve direct state marketing and several separate contracts with organizations occupying various sub-sectors of the energy industry. The likely counterparties fit the profile of, but are in no way limited to members of the banking community, equity gas owners not currently positioned on the ANS, third party marketing organizations, and industrial organizations with naturally short positions.

A variety of representatives of each of the sub-sectors listed above have already expressed interest in discussing such arrangements.

8.3.2.1 Gas Marketing Options

A summary of potential options for gas marketing, their costs, risks, and potential incremental value are described below.

Early long term gas sales prior to project sanction

- The ANGMC will evaluate the benefits of entering into long term sales agreements of the gas.
- Such long term contracts could be valuable in order to support the general financial position of the state prior to project sanction.
- Such contracts could be based on a basket of published or fixed prices and could consist of firm base load volumes and variable volumes.
- The model of international LNG contracts, which extend for 20 to 25 years is also available for consideration, although contracts of this duration are unprecedented in the domestic U.S. market and will require careful analysis before any commitments are made.
- A variety of large marketing companies have already expressed interest in such arrangements.

Firm contracting for gas sales:

- The state will compete directly with corporate gas marketers;
- A single gas sales point provides the state fewer options than major gas marketers, who deliver to multiple delivery points in the North American gas market;
- Management and operating structures are less simple than the spot sales scenario but equally transparent;
- Firm contracting obligates the state to mitigate price and market risks by managing a portfolio of firm contracts and spot sales; and
- Overhead costs increase commensurately to create and support a more sophisticated marketing organization, and to implement the necessary controls.

Spot sales at first market:

- In this case the state is a price taker;
- The marketing function is a low-overhead, primarily book-keeping function;

- The state assumes all of the price risks of that market. Absent a coherent hedging strategy the state also assumes the resulting affects on revenue predictability, and the ability of the state to continuously meet financial commitments;
- Management and operating structures are simple and transparent;
- Downstream capacity commitments and subsequent costs are eliminated; and
- Overhead costs are minimal with this approach.

Joint ventures:

- This option provides a wide variety of potential structures and outcomes;
- A joint venture with a complementary partner—i.e., one who needs or can effectively use gas for their marketing business—may very well make sense:
- If the two entities bring different and complementary strengths to the venture, resulting in an arrangement which adds value above the sum of the parts, and
- A particularly advantageous partner to the state is likely to be a diversified marketer with a wide portfolio of opportunities with which to leverage the value of state gas;

Contracted asset managers:

- This option is similar in some ways to the model largely employed by the APFC;
- The priorities of asset managers are established by the definition of their compensation;
- As expectations grow for the asset managers to capture incremental value for the state, the form of compensation to the asset managers may evolve such that the asset managers may share in an increasing portion of that incremental value;
- The state can shift the mix of asset managers to maximize value to the state as abilities or market realities shift; and
- Effective asset managers bring a broad range of forecasting, financial, marketing, and risk management expertise to the table. As a result, overhead can increase significantly. The cost increase should at a minimum be offset by increasing revenues to the gas marketing entity.

The course of development of ANGMC will depend largely upon the marketing and contracting strategy settled upon by the state, which, in turn, will be structured to respond to expectations of the market at the time contracts are being entered into. Gas market contracts, and their value to a marketer, can vary widely based on a wide number of factors such as:

End user: What is the gas use profile of that industry and that user? What is the economic health of that industry or that user? How does the consumption profile of this user compare with that of other users? Does this user's economic health tend to track with economic cycles, or run counter to them?

Contract: What is the pricing mechanism? What is the consumption profile? What is the term? What are the penalties for either failure to deliver or failure to take?

Economy: What are economic expectations? Can value be gained by long term commitments or by selling on the spot market? What are the risks in the current economy of either strategy? What level of flexibility (spot sales) is necessary to properly manage, guarantee service, and be able to take advantage of short term opportunities? What are gas supply expectations? What are customer expectations—do customers expect to pay to obtain long-term commitments, or will the marketer pay to receive long-term commitments?

Portfolio: Does the basket of potential contracts provide an appropriate mix of exposures to markets, economic cycles, customers, customer types, contract terms, and other factors to minimize risk through diversification?

Finally, similar issues arise, on a somewhat smaller scale, with the marketing of natural gas liquids. These markets are smaller and tend to be more focused upon large industrial users, with long and steady demand profiles. Nevertheless, similar issues as described above should be considered.

All of these issues will be continuously monitored by the ANGMC to ensure the state's marketing entity is flexible and responsive to changing markets, business opportunities, and risks and challenges to successfully marketing the state's gas.

8.3.2.2 Gas Marketing Issues

The issues which must be addressed by the state prior to the creation of ANGMC or by ANGMC after its creation fall into the five general categories: policy, authority, financial, business, and legal. The following discussion provides a framework for each of these categories.

Policy Issues

Policy issues are those which ask questions regarding what ANGMC should do. The decision to take royalty and production payments in the form of gas (state gas) rather than cash has been made, but questions remain regarding the state's role in the business of marketing the gas. Most of these questions pertain to the risks involved in various marketing activities:

- Should ANGMC act primarily as a price-taker in the market, thereby minimizing the overhead and risks but also perhaps minimizing potential gains?
- Should ANGMC participate aggressively in the marketing of natural gas?
- What marketing structure should be utilized?
- What are the characteristics of good partners for ANGMC and what are the risks entering into such partnerships?
- Should ANGMC contract asset managers, more in the style of the APFC?

Financial Issues

Financial issues will require close evaluation. ANGMC will require significant credit backing. Major potential gas customers will enter into gas contracts only with marketers with investment grade credit ratings. Given the structure chosen for a gas marketing entity, can the entity gain access to the state's credit rating? If not, or if not acceptable to policymakers, how does the state establish the credit backing necessary for a marketing entity, particularly if the entity is also responsible for the state's pipeline shipping commitments?

Business Issues

The business environment in which ANGMC is expected to function is likely to shift, before the entity is established, as well as over time afterward. The nature of competition, the expectations of customers, supply considerations, liquidity of markets, Alberta gas pipeline network capacity after Alaska gas pipeline startup, the nature of Canadian gas liquids markets, and a myriad of other issues must be constantly monitored and responded to proactively.

Legal and Authority Issues

The legal issues facing a state gas marketing entity require careful review. The choices made above, concerning policy, structuring of the ANGMC state gas entity, and the types of arrangements entered into will all affect the type and scope of legal issues faced.

Tax Issues

Prior to the creation of ANGMC a number of tax issues will have to be examined, in particular with respect to gas sales in Canada, which under certain configurations may be subject to Canadian corporate income tax as well as methodologies for establishing a valuation point at the US-Canada border.

Table 40. A Timeline for ANGMC

During the first year after the approval of the stranded gas contract
Establish ANGMC
Identify management options/ marketing options
First Open Season
The ANGMC would participate in the first and subsequent open seasons.
Project Sanction Preparation
The ANGMC would participate in decisions regarding participation in the NGL extraction plant and Alberta to lower 48 project
Prior to Project Sanction
Decide on whether early long term gas sales, asset management agreements or joint venture partner ships are beneficial to the State and at that point in time and execute any combination of contracts or agreements as a result
5 Years Prior to First Gas
Close examination of business option economics/optics
Develop governance framework of each of the options
Develop risk policy and consider methods by which risk control can be executed as relates to each of the options
4 Years Prior to First Gas
Staff AK Gas Marketing department
Structure/Design of Asset Management/JV “must haves”
Establish marketing strategy ANGMC
3 Years Prior to First Gas
Execute contracts for 3rd party management (asset mgr, or JV) as appropriate
Complete Compliance/Governance/Risk policies
2 Years Prior to First Gas
Acquire physical space for day to day business operations
Layer-in senior management
1 Year Prior to First Gas
Hire Staff (front-, back-, and mid-office)
Implement operating systems
Put contracts/agreements in place
NAESB purchase and sales contracts
Pipeline pooling agreements
“Soft” asset acquisition (storage and transport contracts)
Commence Trading and Marketing
First Gas
Implement business plan
Re-evaluate strategy
Make required revisions to business plan

8.4 Project Process

The Alaska Gas Pipeline will be the largest single energy infrastructure project ever developed. Due to the magnitude and complexity of the project, project sponsors and the involved state and federal entities would need to take a systematic approach to project development. To reach project sanction, the proponents of this project must go through several steps in order to mitigate risks, reduce costs, and achieve as much certainty as possible.

8.4.1 Front End Engineering and Design

The front end engineering and design (FEED) process is expected to take 12 to 18 months and cost hundreds of millions of dollars. It will entail field work in Alaska and Canada to provide reliable information required for a more detailed engineering and design plan for the proposed project. Once the engineering and field work is completed, the project sponsors will conduct a FERC-regulated open season. FEED must occur before the open season because project sponsors must know the estimated cost and design of the project with enough certainty to promise prospective shippers a reasonably reliable tariff.

8.4.2 Open Season

As FEED is completed, the next major step may be the holding of the open season for the project. The FERC has established the rules that govern the open season.[85] FERC will require that the draft open season notice be submitted to it for review before the open season notice is given by the Project. Once the notice passes FERC muster, then notice of the open season will be given. The open season must last at least 90 days.

Shippers will sign up for the project on a conditional basis; that is, if the project is built at the predicted cost and on the predicted schedule, they agree to long-term commitments to take capacity to ship gas on the pipeline. No rational shipper can be expected to commit to a project without knowing with reasonable certainty what it would cost to bring its gas to the markets where it would be sold. These commitments by shippers are the backbone of financing for the project. The entity that owns the pipeline establishes credit requirements to make certain shippers can fulfill their long-term commitments (see 18 C.F.R. § 157.34(c)(12); Ives). The project sponsors then take those commitments to the financial community to demonstrate how the loans for the project will be paid off.

8.4.3 Application Process in the United States and Canada

The project will involve an extensive application process in both the United States (U.S.) and Canada. The Federal Energy Regulatory Commission (FERC) requires that the proponent of a new pipeline file Exhibit F-IV which is a statement regarding how the applicant proposes to comply with the National Environmental Policy Act (NEPA) of 1969. The environmental regulatory review process for natural gas pipelines in Canada by the National Energy Board (NEB) is similar in scope, intent, and timing to the U.S. process. This subsection describes the federal permitting and authorization process in the U.S. and the environmental regulatory process in Canada.

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[85] As required by the ANGPA, FERC has adopted a set of detailed regulations that will govern the open season process on the Alaska gas pipeline. These may be found at 18 CFR Section 157 summarized in Section 4.4. These regulations require that the notice that the pipeline entity issues to start the open season contain detailed information about the proposed project including its size and design capacity, its expansion potential, its in-service date, its proposed rates and cost of service, delivery points in-state, quality specification and credit requirements, its bid evaluation methodology and bid requirements.

8.4.3.1 Federal and State Permitting and Authorization Process in the United States

In the U.S., the federal government has authority over interstate pipelines: "[t]he need for paramount federal authority here is paramount" (Pub. Serv. Comm'n of Ky. v. FERC, 610 F.23 439, 443 (6th Cir. 1979)). No natural gas pipeline can be built or can operate without a certificate of public convenience and necessity from FERC. As part of this process, FERC requires extensive information about the design and engineering of the pipeline, its projected cost and the possibility of cost overruns, the sources of gas to fill it, and the markets it will serve, and how it will be finances (110 FERC 61,095 at P12).

The process for an Alaska Gas Pipeline has been clarified and simplified with passage of the Alaska Natural Gas Pipeline Act (ANGPA) in October 2004. Section 104 of ANGPA designates FERC as the lead agency in establishing compliance with the National Environmental Policy Act (NEPA) of 1969. NEPA requires a single, consolidated environmental impact statement (EIS) for all federal agencies. The EIS is the driving element in setting the regulatory timeline for FERC. ANGPA establishes a clear and coordinated process for obtaining essential federal permits for the pipeline. ANGPA requires that the draft and final EIS be completed within 18 months of the filing of a complete certificate application and that the application review and approval process by FERC be completed no longer than 2 months after the completion of the final EIS.

With passage of ANGPA, important steps were taken to establish fair rules for access to and expansion of the pipeline. With ANGPA, project developers can reasonably estimate how long it will take to obtain the necessary federal permits for the pipeline once an application is filed; and can expect a much reduced delay from court challenges.

As part of its authorization process, FERC will review almost every aspect of the project including sources of supply, design and cost, specific route, proposed tariffs, existence of shipper contracts (precedent agreements) supporting the project, subsidiaries and affiliates, and construction, operation, and management plans. To expedite processing of the application, FERC staff will work with the project sponsors in a "pre-filing" process. The pipeline entity would work with FERC staff in advance of the application to ensure that the necessary environmental data are gathered in the field and to ensure that the required engineering data are assembled in the form FERC staff require. Once the open season commitments are accepted by the pipeline entity/pipeline sponsors, the FERC application can be prepared.

The certificate issued by FERC will include a long list of conditions related to construction, environmental protection, tariffs, and other items. However, once the certificate is issued, the sponsor has the opportunity to review the terms and conditions to see if they are acceptable or need modification. A project's sponsors are not required to accept the certificate if the terms are not acceptable to the sponsor.[86] The project's financial advisers will also look at the certificate terms and conditions to confirm whether the project can be financed under those terms and conditions. If the sponsors are not satisfied with the certificate, they can seek a rehearing at FERC or go to court.

In addition, the AGPC will be required to obtain rights-of-way from the ADNR and the Bureau of Land Management (BLM). ADNR will issue the lease under AS 38.35, the "Right-

[86] Atlantic Refining Co. v. Pub. Serv. Comm'n of N.Y., 360 U.S. 378, 387-88 (1959) ADD to references

of-Way Leasing Act". Both land management agencies anticipate integration of their respective right-of-way processes into the FERC certification process.

The State of Alaska's policy, as set out in AS 38.35.010, is that development, use, and control of a pipeline transportation system make the maximum contribution to the development of the human resources of this state, increase the standard of living for all its residents, advance existing and potential sectors of its economy, strengthen free competition in its private enterprise system, and carefully protect its incomparable natural environment. The Commissioner of ADNR has been given all powers necessary and proper to implement this policy and to grant leases of state land for pipeline rights-of-way, to transport natural gas under conditions prescribed by AS 38.35.015 and the administrative regulations.

The ROW lease between the state and the AGPC will address a wide range of activities and governs the conduct between the parties. The lease applies to the full life of the pipeline; construction, operations, maintenance, and termination. The underlying theme throughout the lease will be protection of human health, safety and the environment, established by safe pipeline operations and mitigation of environmental impacts.

8.4.3.2 Governmental Authorization of the Project in Canada

One of the fundamental challenges facing the project in Canada is the uncertainty over the regulatory approval process. An important step for the project is clarification of the Canadian regulatory process. This uncertainty arises because of the existence of two distinct Canadian federal legislative regimes. The first, known as the Northern Pipeline Act of 1978 (NPA), was enacted to assist the permitting of Canadian segments of the Alaska Natural Gas Transportation System ("ANGTS"). The NPA and related issues are discussed in Section 8.2.6.

The second regime is the National Energy Board Act (NEBA) of . The NEBA is modern legislation that establishes the regulatory process to be used whenever inter-provincial or international pipeline projects are proposed. The NEB process is well known and clearly understood when compared to the NPA. The National Energy Board (NEB) is a quasi-judicial board which has jurisdiction over Canadian natural gas pipelines crossing national or provincial boundaries. The jurisdiction of the board was extended in 1997 to cover essentially all federally regulated commodity pipelines. Major projects must apply for a Certificate of Public Convenience and Necessity pursuant to Section 52 of the NEB Act.

8.4.4 Canada

The major portion of a pipeline from the ANS to Chicago will be in Canada. This report has identified issues for constructing and operating the project in Alaska, as well as steps to deal with the issues, and the potential benefits to the State of Alaska. This section summarizes the issues, strategies for the state to consider, and benefits the project will provide to Canada.

8.4.4.1 Issues

Regulatory Regime

As it concerns a pipeline to deliver ANS gas across Canada to U.S. markets in the Lower 48, perhaps the highest profile issue concerns the question of which of two possible federal regulatory regimes will apply to the project in Canada.

The Northern Pipeline Act

The right to construct, own, and operate the Canadian portion of a pipeline for the transmission of Alaskan gas through Canada, specifically along the Alaska Highway route, was contested in a lengthy, competitive National Energy Board (NEB) public hearing in Canada in the late 70's. That hearing resulted (see below) in the issuance of certificates of public convenience and necessity (CPCNs) to construct, own, and operate the Canadian part of the project to Foothills Pipe Lines Ltd., now a wholly-owned subsidiary of TransCanada.

The NEB hearing was followed by the execution of a treaty level "Agreement Between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline," dated September 20, 1977 (Agreement).

The Agreement sets forth a timetable that ends with initial operation of the pipeline by January 1, 1983. The Agreement describes not only the specific route for the pipeline that was the subject of the CPCNs but addresses the capacity, financing, taxation and many other aspects of an Alaska Highway pipeline. In an Annex, it describes the Foothills subsidiaries that would build various segments of the Canadian portion. Article 14 states that the two Governments "recognize that legislation will be required to implement the provisions of this Agreement." The Agreement remains in force for a period of 35 years and thereafter until terminated upon 12 months' notice, by either Government. The Agreement also provides for the delivery of gas to certain communities along the pipeline's route.

The Parliament of Canada then enacted the Northern Pipeline Act (NPA), confirming the rights of Foothills legislatively and declaring that CPCNs would issue to Foothills, for a pipeline along the route in the Agreement. The NPA adopts the Agreement (it is a Schedule to the legislation) as Canadian law. The objects of the Act are to implement the Agreement, to facilitate the "efficient and expeditious planning and construction of the [Alaska Highway] pipeline" taking into account local and regional interests and the interests of the native people, to ensure just and equitable resolution of native land claims, to facilitate consultation and coordination with the provincial governments and the Yukon and Northwest territories, to maximize social and economic benefits from the construction and operation of the pipeline, including employment opportunities for Canadians, and to advance Canadian economic and energy interests through extensive involvement in the pipeline's planning and construction and its procurement of goods and services. The Northern Pipeline Agency (Agency) was created by the NPA. It was intended to be a single window, expeditious regulatory regime, and was provided with the authority to regulate the development and construction of the Canadian portion of the Alaska Highway pipeline, as that facility is proscribed in the Agreement and NPA. TransCanada asserts that the NPA regime is flexible and provides discretion for approvals that meet modern standards and design requirements (which were met for the pre-build construction, see below), without the need for any amendment of the NPA. The NPA has always reserved to the NEB the authority to regulate the tolls and tariffs of the pipeline in Canada, once it is in service. The NPA framework for the development, construction and ownership of the pipeline remains in place today in Canada. The Northern Pipeline Agency approved the construction of the “pre-build” facilities for the Alaska Highway pipeline in Canada, which transports approximately 3.0 Bcf/d of natural gas to North American markets. It has also approved five expansions of the pre-build, the latest of which occurred in 1998. No potential competitor has legally challenged the NPA framework since its inception, nor has the Government of Canada indicated that it intends to set aside this regime for the pipeline.

The facilities that were pre-built in Canada for the pipeline are fully integrated with TransCanada’s system, which has sufficient capacity to accommodate the initial expected volumes of Alaskan gas to be transported on the Alaska Highway pipeline, without significant new construction. The two major extraction facilities that remove natural gas liquids from natural gas volumes are located on the pre-build facilities, and are also anticipated to have significant spare capacity to accommodate Alaskan gas.

Utilization of the NPA would allow the project to make use of Foothills’ NPA-sanctioned right of way interests in certain Yukon lands, as is explained below.

In order to expedite the project, TransCanada has engaged in commercial negotiations with the ANS Producers to resolve issues related to the Canadian portion of the pipeline. TransCanada stated that its preference is not to delay the project with an adjudication of its rights, however the possibility of that outcome cannot be dismissed.

National Energy Board Act (NEBA)

The producers do not accept the proposition that TransCanada has the exclusive rights to construct, own and operate the Canadian portion of the project on the basis of the approvals issued under the NPA. In their view, the NPA was made in respect of a specific project, namely the ANGTS, and the project TransCanada has now under consideration is significantly different from that, in particular, due to the fact that the project no longer would simply transit gas across or through Canada, but instead would (a) be accessible to Canadian gas sources and (b) would make deliveries of ANS gas to Canadian markets. The producers assert that significant amendments (including amendments to the agreement underpinning the NPA, as well as potentially NAFTA) would be required in order for other projects to fall within the NPA. The need for such changes, it is argued, effectively negates any timing, process, or certainty advantage otherwise provided under the NPA.

The producers have been careful not to suggest that rights granted under the NPA are without value or merit. This may be because the NPA has granted to TransCanada right of way easements over lands that are now the subject matter of First Nation Treaties. However, the producers view the NEBA as a well-understood process that provides regulatory certainty and timing efficiencies. Moreover, the NEBA also provides CPCN holders with the right of eminent domain (i.e., rights to expropriate interests in land), over both private and public lands, including interests which may otherwise be held by First Nations. It should be noted that the Mackenzie Valley pipeline, which is being conducted pursuant to the NEBA regulatory process is scheduled for a protracted regulatory hearing of over a year to accommodate public review in most aboriginal communities along the route. Mackenzie

Valley pipeline project sponsors have spent the last several years negotiating benefit and access agreements along the route of the pipeline.

First Nations' Interests

The rights of aboriginal groups—the First Nations—must be addressed for any pipeline project in Canada to succeed. In the normal course, a new pipeline would seek both a right of way to cross First Nations' lands and a benefits agreement with each affected First Nation. In the Yukon, the right of way interests are well developed under the NPA and major First Nations' interests addressed. Use of the NPA sanctioned right of way could avoid or substantially reduce the scope of negotiations with First Nations in the Yukon. In Alberta and British Columbia, the right of way interests under the NPA are less developed and consist in British Columbia of "map reserves" and in Alberta of "consultative notations" for an Alaska gas pipeline.

Provincial and Territorial Interests

Careful attention also must be paid to the interests of the governments of Yukon, British Columbia and Alberta. In March 2006, these governments issued a statement establishing eight principles applicable to any Alaska Gas Pipeline Project. First, the governments say that the regulatory process in Canada must "be clear and efficient to advance" the Project, provide for participation by those governments and coordination with their regulatory requirements, and ensure thorough environmental and socio-economic impact assessments. Second, First Nations' interests must be appropriately addressed. Third, employment and business opportunities must be maximized for the citizens of those provinces and territories. Fourth, the benefits from the project must "meet or exceed" each jurisdiction's requirements relative to the costs it will impose. Fifth, each province or territory must have "physical access" to energy from the pipeline on commercial terms and gas on the pipeline "must have physical and economic access to existing infrastructure" in Canada. Sixth, gas from those provinces or the territories must have access to the pipeline. Seventh, there must be adequate takeaway capacity to avoid "trapped gas." Eighth, the Government of Canada must respect the "provincial and territorial jurisdiction" of each province and the territories." All of these requirements are met by either of the NPA or NEBA regulatory regimes.

While the Alberta government is not specifically seeking to pick either the NPA or NEBA regulatory process, it has certain practical requirements that bear on which process is selected. It is opposed to a bullet—or true transit - line that would entirely bypass existing infrastructure and wants the project to use existing pipeline infrastructure in Alberta. It also wants the pipeline to allow for gas liquids to be stripped out by the petrochemical industry in Alberta in the most commercially advantageous manner.

8.4.4.2 Proposed Canadian Strategy

The complexity of the Canadian issues should not be underestimated nor the need for a commercial solution minimized. Yet the potential benefits to both Alaskans and Canadians from the project are pronounced and quite significant. They include the potential for a larger and more liquid Alberta market hub, greater and more efficient utilization of Canada's existing pipeline infrastructure, opportunities to provide new feedstock supply to existing petrochemical plants in Alberta and the ever increasing demand within Alberta, and the potential for new gas development in the Yukon. These benefits are addressed below.

The State of Alaska must consider these issues from two perspectives. The first concerns its commercial interest and role as a co-proponent of the Project. The second concerns its sovereign interest and role in facilitating efficient government regulatory proceedings into cross-border developments. Taking into account both perspectives, the state believes there is a high value to an aggressive pursuit of cost-effective commercial solutions to these issues involving all of the affected interests. The state believes that all parties share an interest in and must be committed to a timely and comprehensive solution to the Canadian issues. For the Project to move expeditiously ahead, it is essential that TransCanada and the producers and, in fact, all of the affected interests, find an acceptable, commercial solution to the outstanding Canadian issues.

8.4.4.3 Expected Benefits of the Project to Canada

The proposed Alaska natural gas pipeline is expected to generate significant economic benefits to the Canadian natural gas industry and gas consumers once ANS gas flows through the mainline from Prudhoe Bay to Yukon, British Columbia, and Alberta. The nature and the magnitude of these benefits are dependent upon the level of gas production from the Western Canadian Sedimentary Basin (WCSB). This gas basin is currently the most important production area for the Canadian gas industry. Both the National Energy Board (NEB) and its provincial counterpart, the Alberta Energy Utilities Board (AEUB) have projected steady and discernible declines in natural gas production from the WCSB beginning in the next two to three years. WCSB gas production recently reached a plateau of approximately 16.5 bcf/d, despite record levels of drilling activity.

By 2015, when the Alaska gas pipeline is expected to begin operations, the NEB has projected that western Canadian gas production could decline to approximately 14 bcf/d from its current level of 16.5 bcf/d. This projection assumes that Mackenzie Delta gas production increases to 1.8 bcf/d by that date. A loss in gas production of this magnitude would likely result in significant excess capacity on Canada’s pipeline infrastructure and under-utilization of the industry’s marketing resources. The decline would also place constraints on Alberta’s petrochemical industry and development of Alberta’s oil sands resources. The demand for natural gas is also expected to continue to grow across Canada and particularly in Alberta, where the demand for natural gas to fuel oil sands production is growing dramatically. The NEB is forecasting that gas consumption in Canada will increase to almost 11 bcf/d by 2015. Declining WCSB production capability in the face of growing demand would cause higher and more volatile natural gas prices compounded by higher pipeline transportation costs. Higher gas prices and pipeline costs and the attendant uncertainties could lead to fuel switching programs, downsizing of the petrochemical industry, limited development of oil sands deposits, reduced gas exports, and a shrinking pipeline construction industry.

An Alaska gas pipeline across Canada will be valuable insurance for the Canadian gas industry and gas consumers against the negative consequences of declining production from the WCSB. In particular an Alaska pipeline to Canada is expected to generate the following benefits:

A larger and more efficient Alberta market hub.

The Alberta Hub, often referred to as the AECO/NIT market, is the largest and one of the most efficient gas markets in North America. The possibility of up to 4 bcf/d of Alaska gas being traded on the Alberta Hub would diversify the source of gas supply traded, increase the number of active buyers and sellers (market depth), and may offset the loss in liquidity related to any decline in production from the WCSB.

The owners of Alaska gas will also benefit from the advantages of a large, efficient marketplace including more stable prices, and lower transaction costs compared to selling Alaska gas at smaller, less diversified markets.

Greater and more efficient utilization of Canada's existing pipeline infrastructure

Downstream of a connection between the Alaska pipeline and the Alberta market hub is an extensive network of large pipeline systems that can transport Alaska gas to major U.S. markets. These are open access pipelines, several of which currently have excess capacity that is expected to increase over the next decade as production from the WCSB declines. To varying degrees, each of these pipelines will have un-contracted capacity available by 2015 and would welcome the prospect of transporting Alaska gas. From the perspective of WCSB producers, refilling the excess capacity on the Canadian pipeline grid could generate more than $600 million per year of net revenue on average after net revenue.

Viewed from the perspective of owners and shippers of Alaska gas, benefits will accrue from accessing low cost spare capacity on existing pipelines without the risk of cost over runs.

Such pipeline capacity is held by at least three independent pipeline companies (e.g., Duke, Alliance and TransCanada). Each of these pipelines will be competing vigorously for Alaska gas to refill their systems, thus ensuring that Alaska shippers will receive low cost, competitive service. It is noteworthy that the spare capacity of TransCanada's gas transmission infrastructure exceeds the total existing capacity of Alliance or Duke.

Opportunities to sustain and enhance Alberta's petrochemical industry

It is expected that the gas transported on the Alaska pipeline will contain a mixture of NGLs, primarily ethane, and serve as a long-term secure feedstock source that would allow existing feedstock extraction and fractionation.

From the perspective of the owners of Alaska gas, the Alberta petrochemical industry will be an attractive market for at least 200 mmcf/d of Alaska gas. Alberta offers large scale economies at its ethane extraction plants, efficient feedstock delivery systems, world scale petrochemical facilities and access to world markets.

Potential for new gas resource development, particularly in the Yukon Territory

There are several promising natural gas resource accumulations located in the Yukon Territory, such as in the Whitehorse Trough (with an estimated resource potential of 7.3 tcf), that could remain stranded indefinitely without an Alaska gas pipeline. The construction of the Alaska pipeline is likely to spur gas exploration throughout the Yukon Territory and to the extent that reserves are discovered, particularly in the vicinity of the Alaska pipeline, significant benefits will accrue to producers and the Yukon Territorial Government in terms of royalty revenues.

There are also some large mines in the Yukon located in the vicinity of the pipeline corridor that could benefit from access to natural gas as a heating source or to generate electricity for their operations. Finally, natural gas could also serve as a cheaper alternative to heating oil for residential and commercial uses in major centers that are in proximity to the pipeline route, such as Whitehorse.

The Mackenzie Valley Pipeline Project

The Mackenzie Valley Pipeline project is currently scheduled for an in-service date in 2011-2012. This schedule would allow for the maximization of synergies with the Alaska pipeline project in that it could supply an experienced labor force and an orderly staging of supplies and equipment.

8.4.5 Project Sanction

In addition to the issuance of an acceptable FERC certificate upon completion of the FERC application process, the LLC agreement currently contemplates that the following conditions will need to be satisfied prior to the holding of an AGPC management committee vote to begin construction of the mainline:

- AGCP shall have obtained all governmental approvals necessary to commence construction of the mainline;
- AGCP shall have completed an open season under which sufficient initial capacity has been subscribed;
- AGCP shall have entered into a binding transportation agreement with each subscriber for capacity;
- The operator shall have determined the estimated project cost;
- The project entity owning the Alaska to Alberta portion of the project shall have committed to construct its portion of the project;
- Satisfactory commitments have been obtained with respect to the construction of additions to downstream pipelines as may be necessary to transport gas from the mainline and the Alaska to Alberta portion of the project to any ultimate delivery points;
- The operator has negotiated construction agreements that have been approved as required under the operating agreement; and
- The finance plan has been approved.

Upon satisfaction of these conditions to construction, the members will be entitled to vote in favor or against commencement of construction of the project in its discretion. The representatives of the members, directly or indirectly, owned by the producers must each vote in favor of commencing construction in order for project sanction to occur.

This is known as the sanction decision and is the critical make or break decision on the project. All of the pieces—engineering, regulatory, financing, gas supply, markets, and customers, and cost-—must come together to make the project not only viable, but attractive, compared to the alternative opportunities for the investment of the members' capital. Given the necessary steps outlined above—field work and detailed engineering aimed at produced a reliable cost estimate, preparation for and conducting an open season, negotiating the precedent agreements, and the FERC application and certification process—it could very well be four to five years before the time of project sanction arrives. Also, the members will review and approve the whole project—the gas treatment plant, the mainline, feeder pipelines, and the Alaska to Alberta pipeline at a minimum. Thus, they will need confidence that the necessary authorizations and permits for the Canadian aspects of the project are also in place. Because so many of the core elements of the project vary over time, no member could make an unequivocal commitment to proceed with the project until the elements of the sanction package are settled.[87]

8.4.6 Construction and Startup

After member sanction is given, the operator, on behalf of AGPC, will undertake procurement activities such as ordering the thousands of miles of pipe, hiring construction contractors, staffing up from their own resources for project management, and undertaking final design in conformance with the requirements of the permitting agencies. State and federal agencies will implement project oversight and monitoring plans once field activities commence. It is expected that construction will take three years. Once construction is completed, the pipeline is tested and then commercial operations commence.

[87] FERC, 2006.

9 Preliminary Findings and Determination of the Commissioner

In the foregoing sections of this document, findings have been made comparing the projected public revenue anticipated from the project with the estimated operating and capital costs of the additional state and municipal services anticipated to arise from the construction and operation of the project. Facts have also been set out regarding the reasonably foreseeable effects of the proposed contract on the public revenue. Findings have been made regarding the potential benefits of the contract, the means to develop and market the state's stranded gas resources, and the possible costs and risks of entering into the obligations set out in the contract. The commissioner has taken a broad perspective in conducting the analysis presented here, incorporating a review of North American gas markets and global gas supplies, and comparing the proposed gas pipeline project with other options. The following sections discuss the commissioner's determination that the contract best serves the long-term fiscal interests of the state and furthers the purposes of the SGDA, as amended.

9.1 Criteria for Preliminary Findings and Determination

Before a contract under the SGDA can be presented to the public and the legislature, the commissioner of revenue must make preliminary findings and determine whether the contract is in the long-term fiscal interest of the state and furthers the purposes of the SGDA (AS 43.82.400(a)(1)).

In making this fiscal interest determination, the risks to the state treasury presented by owning equity in a gas line and engaging in the business of shipping gas were considered. In making these judgments, reliance was placed on the department's expertise and knowledge in administering the revenue and tax statutes of the state, expertise of the department of natural resources, the attorney general, and the advice of independent experts.

The legislature required that the preliminary findings and determination include a determination whether the contract furthers the purpose of the SGDA (AS 43.82). This was interpreted to mean that the findings and determination must meet the purposes of the Act stated in AS 43.82.010(1) – (3), as amended. These purposes include:

(1) Does the contract encourage new investment to develop the state's stranded gas resources by authorizing fiscal terms related to that new investment?

(2) Does the contract allow fiscal terms applicable to a qualified sponsor group to be tailored to the particular economic conditions of the project and to establish those fiscal terms in advance with as much certainty as the Alaska Constitution allows?

(3) Does the contract maximize benefit to the people of the state derived from the development of the state's stranded gas resources?

In addition to an analysis of the purposes of the SGDA, specific findings were made whether ANS gas is stranded as required by AS 43.82.900(13), and whether the Act accomplishes the policies set out in AS 43.82.210(b). Specific findings were also made whether the contract accomplishes the policies set out in AS 43.82.210(b). The SGDA requires a description of the principal factors, including the projected price of gas, projected production rate or volume of gas, and projected recovery, development, construction, and operating costs, upon which the determination is based. This factual information is provided in Section 4 of this document.

In making the specific determinations set out below related to furthering the purposes of the SGDA, the determinations are conditioned on the necessity of making amendments to the SGDA and other applicable statutes that are appropriate to satisfy the legislature's underlying purpose of developing the state's stranded gas resources in a fiscally responsible manner. These amendments and others considered necessary to properly implement the contract are set out above in Section 8 and the applicable appendices of this preliminary findings and determination.

The SGDA expressly requires a comparison of projected public revenue derived from a qualified project with the additional state and municipal capital and operating costs caused by the construction and operation of the project. A comparison of these revenues and costs is used in part to arrive at the reasonably foreseeable effect on public revenue caused by the implementation of the contract.

Whether the fiscal terms of the contract are customized to the conditions of the project and sponsor group is essentially a question of fact. The terms of the contract were negotiated at arm's length with the commercial interests of the sponsor group balanced against the public interest to be protected by the state. The question of whether the fiscal terms of the contract were established "with as much certainty as the Alaska Constitution allows" is a question of law. In that regard, advice was received from the attorney general that the fiscal terms of the contract do not violate the Alaska Constitution.

9.2 Preliminary Determinations of the Commissioner

Under AS 43.82.400(a)(1), the commissioner of revenue is required to determine whether the contract is in the long-term fiscal interest of the state and meets the purposes of the SGDA. In making this ultimate determination, the reasonably foreseeable positive and negative effects of the contract on public revenue was considered, including additional costs anticipated to arise from the project. Also relied upon were the facts set out in the foregoing sections of this document and the applicable laws proposed for amendment as described in Section 8. In this section, a formal determination is also made that the contract furthers the purposes of the SGDA.

Based on the foregoing findings of fact set out in earlier sections it is determined that the approved qualified plan of the sponsors to develop a gas pipeline provides the best available opportunity to the state for bringing the state's stranded gas resources to market in a timely manner.

9.2.1 ANS Gas is Stranded

Appendix C contains the commissioner of revenue's economic analysis of whether ANS gas is stranded. This analysis is required by AS 43.82.900(13). Based on the analysis set out in appendix C, it is determined that ANS gas is stranded for the purposes of the SGDA.

9.2.2 Contract is in the Long-Term Fiscal Interest of the state

Generation of Additional Revenue is the goal of the contract.

The contract is in the long-term fiscal interest of the state because it offers a means for providing substantial additional revenue to finance the operations of state and local government. Without this contract it is likely that a gas pipeline would not be built soon enough to provide new revenues to the state treasury within the timeframe they are critically needed in order to offset forecasted declines from existing revenue sources. To determine the foreseeable effect on the public revenue, it must be considered how the state treasury will fare in the coming years. The Department of Revenue has consistently stated the opinion that declining oil production along with the month-to-month volatility of oil prices will continue to cause uncertainty in the state's ability to anticipate the receipt of oil and gas royalties and tax revenues. These revenues will make up 75 percent of the state's forecasted general purpose revenue needed to meet appropriations to finance state government. Based on forecasted revenue anticipated for the state beginning after fiscal year 2009, the state's revenues will not be enough to meet the anticipated shortfall even with the substantial new revenue source provided by the PPT. In order to counter this real threat to the long term fiscal interests of the state, it is determined that the state must act to establish additional new sources of revenue to prepare for the decline in oil production.

By contracting to provide stable tax regimes, participating as an owner, and taking financial responsibility for the capacity to ship its gas on the mainline, it is determined that the state has provided commercially reasonable inducements to influence a timely and favorable decision to commence the feasibility and regulatory work obligations of the sponsor group and create a higher probability that the required investment in the project will be made on the project sanction date.

It is determined that the revenues that would accrue to state and local governments would be substantial. Royalties on produced gas that is no longer stranded would be an additional source of revenue that will materially change the state's long term fiscal interests. The return on the state's equity investment will also help to provide a modest but stable source of revenue.

The government share of project revenues is fair.

It is determined that the state's share of project revenues is comparable to other taxing jurisdictions.

This is a competitive government share of project revenues compared to other long distance gas exporters aimed at the Lower 48 US market. It is determined that the contract provides the state with a fair share of the revenues of the project as compared to the burden imposed on gas exporters by other taxing jurisdictions.

A Stable Fiscal System is a necessary inducement.

The stability necessary to satisfy the purposes of the SGDA is a fiscal system with payments in lieu of taxes set in amounts that approximate the rates in effect under law existing for the 2005 tax year. This stability is the single most important feature of the contract that achieves the purposes of the SGDA. In order to induce the sponsors to commit to develop the project, the contract must be structured in a way to enhance the profitability of the project so that it competes favorably with other gas projects in the world.

The fiscal certainty offered by the contract serves as a counterbalance for the possible economic, financial, resource, political, and regulatory risks that must be considered in any investment decision. It was considered that some of these risks occur outside Alaska.

As indicated in Section 5.1 of this report, cost overrun risk is a very serious risk which could make the project uneconomic under unfavorable price scenarios. The cost overrun risk can be mitigated by careful project planning, as explained in Section 6 of the report. The work obligations are structured so that this process can unfold in an optimal manner.

Resource risk is considered to be significant, but not of a magnitude to cause the state or an investor to decline to proceed with the project. Based on the data recounted in Section 1, there is likely to be enough gas available to fill the gas line for the economic life of the project. The contract contains provisions intended to encourage exploration and the addition of new leases to production.

It is determined that the state would be acting prudently to undertake its obligations under the contract even though it will be desirable to bring additional reserves into production in order to achieve the volumes of gas necessary to fill the gas line for the duration of the stranded gas contract.

At this time, there is not enough known about the design of the gas line or the means that will be used to contract for construction to make a definite determination about the economic risk presented by construction. Therefore, the state expects that the AGPC (mainline entity) agreement will include the right for the state to withdraw from participation with recovery of prior costs in case the state decides not to proceed with the investment on the project sanction date.

The state will own 20 percent of the gas line and could be responsible for unanticipated cost overruns. This ownership interest and taking possession of the gas serve to make the project potentially a more profitable project for the sponsor group. The state has made this project more competitive in the global project portfolios of the sponsor group by taking gas in payment for production obligations and by also taking financial responsibility for shipping the gas. It is presumed that the state will act as a reasonable and prudent owner along with the other owners and will use commercially reasonable means available to control costs and provide as much advance notice as possible to the legislature so that steps can be taken to protect the treasury from undue risk.

Based on the department's risk analysis of the effect of a cost overrun, it is determined that even under highly unlikely low gas prices, the state will not suffer a significant impairment of revenue by undertaking the obligations of the contract. No one can foretell the status of markets a decade or more in the future. There is a risk, which cannot be ignored, that gas transported through the mainline after project sanction will be too costly to compete with other sources of gas.

To a certain extent, the willingness of the sponsor group to move forward with the project serves as a market test upon which the state can place some reliance. As discussed in Section 6, there are means and methods available to the state to further reduce market and shipping risk. It is reasonable to presume that state agencies responsible for marketing and pipeline operations will develop prudent marketing strategies and will exercise their functions in a way that further reduces these risks.

It is determined that the marketing and shipping risk is manageable to the extent that it will not pose a significant threat to the long term fiscal interests of the state. It is further determined that the specific state risk sharing and participation proposal embodied in the contract improves the project enough under low prices to make the project an attractive investment, without creating unnecessary increases in profits under high price scenarios.

The contract is intended to mitigate fiscal risk to the gas line project that may be caused by law changes in state and local governments with jurisdiction to tax the project. Under the contract, the sponsor group will be given fiscal certainty regarding specified tax and regulatory law for a term of years. To the extent that these protections take the form of valid contractual obligations, the sponsors are protected by the Contract Clause of the state and federal constitutions. The basic assumption underlying this determination is the necessity to provide a guarantee of stability of state and municipal taxation systems. The state has determined that stability is necessary to protect against the risk that project profitability could change when a taxing jurisdiction increases the tax burden of the project after substantial investments have been made. Lack of fiscal stability would expose investors to:

- significant possible erosion of value to the point where the project becomes unattractive, taking into consideration capital invested in the past, and
- significant exposure to low market prices for gas and cost overrun conditions.

It is determined that it is appropriate and in the long term fiscal interests of the state to grant fiscal certainty for the project under the terms of the contract. The contract promotes the long-term fiscal interest of the state by encouraging new investment to develop the state's stranded gas resources, thereby increasing revenues from taxes on oil and contract payments and fees relating to gas.

The state's preferred financing option is to fund its equity ownership in the project with direct appropriations (cash) and to fund its debt requirements with limited recourse debt issued by a public corporation established to exercise the state's ownership functions. These actions will enable that state to take advantage of the federal loan guarantee. It is determined that these measures are reasonable and prudent to protect the long term fiscal interest of the state in limiting the fiscal risks associated with the state's involvement in the project.

The period of stability granted is reasonable.

The term of the contract would cover the 10 year period of project development (e.g., permitting, engineering, planning, procurement, and construction) plus an additional 35 year period after the commencement of commercial operations. Within this term, different periods of stability are provided for taxes on oil and gas. Fiscal stability for gas applies for the duration of the contract, while fiscal stability for oil is limited to 30 years from the effective date of the contract. It is determined that this period is reasonable to cover the depreciation period expected to be set for the gas pipeline. The depreciation period is important for rate setting purposes and will be set after considering the reserves available for transportation through the gas line. It is expected the FERC will initially require capacity commitments that will extend for 15 to 20 years. It is reasonable to assume that lenders to the project will expect a useful life for the project to extend for a period beyond the capacity commitments so that there is sufficient flexibility to restructure financial arrangements in case of unforeseen circumstances.

It is determined that the 35 year period of fiscal certainty for gas granted after the commencement of commercial operations is reasonable and necessary to provide an effective inducement to build the project. It is also determined that a period of fiscal certainty is necessary to cover the period to develop additional reserves to fill the gas line to capacity for the duration of the contract.

Ensuring that the pipeline is full for the contract term increases the probability that investment decisions will be approved at the project sanction date. The main beneficiary of increased production is the state, which will receive significantly more revenues proportionately with the increased volumes. After the debt financing is paid off in 20 years or so, the pipeline tariffs will decrease resulting in higher wellhead value for the state's gas. It is in the state's best interest to take actions that would increase the volumes to be produced and transported through the mainline.

The 30-year period of fiscal certainty for oil is designed to provide a stable regime until such time as future decisions for available supply must be made to keep the mainline full for the contract term. This is the critical period when new gas supplies must be identified and developed for the Alaska natural gas pipeline project to succeed. New exploration efforts will typically be for oil as well as gas. Exploration decisions are justified on the basis of the possibility of making oil as well as gas discoveries. Therefore, in order to stimulate new exploration, fiscal stability for oil as well as gas is required. A detailed analysis of international exploration and production contracts indicates that a 30 year fiscal certainty period is a relatively short period for the high cost and high risk areas such as the ANS. This is the minimum period required to stimulate significant new exploration efforts.

The contract has a neutral effect on state revenue.

The reasonably foreseeable effect of the contract on state revenue has been evaluated against the 2005 fiscal terms. This has been done assuming the hypothetical circumstance that a gas line could be timely constructed without the inducements offered by the contract. This analysis was undertaken to determine whether on balance the contract terms are comparable to the 2005 fiscal terms. Information presented in Sections 4 and 5 shows gas revenues are comparable under either fiscal structure, with gas revenues being slightly less on a net present value basis. The results for gas are similar because the contract terms retain the same royalty share for the state, and the contract production payment of 7.25 percent is approximately the same as the existing production tax when adjusted by the project economic limit factor, while the state corporate income tax also remains unchanged.

As the foregoing demonstrates, the contract provides inducement through stability, not by materially reducing the present day tax burden on the project. It is determined that the foreseeable effect of the contract is not to appreciably diminish the state's revenues as compared to the status quo fiscal system.

State and local impacts are not fully known but would be offset by new revenue sources derived from stranded gas.

As required in AS 43.82.400(2)(b), the projected public revenue anticipated from the approved qualified project was compared with the estimated operating and capital costs of the additional state and municipal services anticipated to arise from the construction and operation of the approved qualified project.

As described in Section 5 of this finding, it is estimated that $125 million (2003 dollars) in additional expenditures would be incurred by state, municipal, and village governments in support of education, health, public safety, and other services during the project pre-construction and construction period. Based on data from the department of transportation and public facilities, the cost of transportation projects that need to occur prior to pipeline construction may approach $400 million. The cost of system rehabilitation after construction may approach $800 million.

These projected economic impacts are partially offset by $125 million that the contract requires be paid in impact payments during the pre-construction and construction period. As an equity partner in the project, the state would be obligated to pay 20 percent ($25 million) of the impact payments. Thus, the net projected public revenue anticipated from the approved qualified project during the pre-construction and construction phase would represent about 11 percent of the total estimated costs of the additional state and municipal services. It is likely that federal matching money will be available to offset some of the cost of improvements eligible for federal financial participation and the sponsors may contribute to some costs for projects directly benefiting project facilities or caused by construction activity. Therefore, the amount of economic impact on the state treasury will not be known until authorizations for federal grant programs are enacted and contributions from sponsors are determined. It is determined that these costs would be more than offset by the additional revenue coming to the state as a result of pipe line operations and the marketing of the state's gas.

In the short-term, development of the project may place significant capital and operating costs on state and municipal governments for the extension of services to residents and other infrastructure needs. The participants in the project will provide impact money to affected municipalities to offset these costs in part. Because of the effects of inflation, it is possible that this assistance will not fully cover all of the costs to be experienced by local government. It is determined that this is a short-term effect attributed to the project which does not significantly diminish the long term fiscal effect of the contract.

The state is acting reasonably to anticipate national and international political action affecting the project.

The state cannot go beyond limits of its sovereignty to alleviate other forms of political risk. Federal law has been enacted to encourage development of a gas line so any potential risk from federal political actions is discounted accordingly. International political risk is something that the state has little role in alleviating. External relations with foreign governments are exclusively within the realm of the federal government. The state will continue to stay in close contact with Canadian officials and officials from Alberta, British Colombia and the Yukon Territory so that there is clear understanding of the positions of all interested parties. It is reasonable to assume that Canada and the provinces and territory will benefit from the project and will therefore be receptive to assisting the sponsors in implementing the project. The long standing friendly relationship between Canada and the United States is expected to alleviate some of the political risks of this project.

It is determined that state officials have been reasonable and prudent in their efforts to understand and anticipate any political risk associated with the state's performance of the contract.

General determination of long term fiscal interest.

Based on the foregoing, the proposed terms of the contract are determined to be in the long-term fiscal interest of the state.

9.2.3 Contract furthers the purposes of the SGDA

A criteria set out in AS 43.82.400(1) for determining whether the contract can be presented to the people and legislature for review and subsequent authorization is whether the contract furthers the purposes of the SGDA. The following paragraphs are headed with each of the three purposes expressed by the legislature in AS 43.82.010 underlying the SGDA. Set out after each of these statements of purpose are the commissioner's determinations with regard to those purposes.

9.2.3.1 Encourage new investment.

> *Encourage new investment to develop the state's stranded gas resources by authorizing establishment of fiscal terms related to that new investment without significantly altering tax and royalty methodologies and rates on existing oil and gas infrastructure and production.*

The proposed contract will encourage investment in the single largest gas development project in the world and will result in the development of the state's stranded gas. Furthermore, the estimated technically recoverable ANS gas resources are not enough to operate the pipeline for the 35-year term of the contract. Exploration and development opportunities for new market entrants are critical for the state's future. The contract encourages exploration by providing a means for expanding capacity of the pipeline system when future discoveries are made and reserves identified. These expansions will help ensure that new gas discoveries get to market. Open seasons for nominating additional capacity requirements will be conducted in accordance with the FERC or NEB requirements. If this need is demonstrated by creditworthy prospective buyers, the contract sets forth a process by which the mainline entity will provide the necessary expansion.

The contract would also allow new ANS leases to be covered by the fiscal certainty provisions if gas from those properties is committed for transportation through the gas pipeline and third parties can enter into similar arrangements under uniform upstream fiscal contracts. This situation encourages exploration for new ANS gas by allowing new oil and gas properties to obtain the stable tax environment needed to induce investment in production facilities necessary to sustain the project.

The contract:

- provides for a production payment rate that is estimated to be about equal to the current effective production tax rate,
- does not alter royalty rates,
- does not alter corporate income tax rates,
- does not alter property taxes on oil installations, and
- does not alter the recently approved rates for the PPT.

The proposed fiscal terms alter corporate income tax, production tax, and royalty methodologies for new gas infrastructure and production. These terms were considered necessary to meet the realities of today's oil and gas business in the state and to provide a reasonable inducement for the project. By taking gas in payment of a tax, the ownership interests of the state and the producers are aligned. Each will own a share of the project roughly equivalent to the amount of gas committed for transportation. This is the basis of a risk shifting arrangement that is considered essential for the profitability of the project. Amendments to the SGDA are presented to the legislature to conform the provisions of the contract to the enabling statutes.

Based on the foregoing, it is determined that the contract will encourage development of the state's stranded gas through the establishment of fiscal terms. These terms would alter tax and royalty methodologies on existing oil and gas infrastructure and production, but only to the extent that would be permitted by law.

9.2.3.2 Fiscal Certainty

> *Allow the fiscal terms applicable to a qualified sponsor or the members of a qualified sponsor group, with respect to a qualified project, to be tailored to the particular economic conditions of the project and to establish those fiscal terms in advance with as much certainty as the Constitution of the State of Alaska allows.*

The project will be one of the largest private enterprise projects in the world and North American history entailing significant risks to the participants and the state. Potential delays in the permitting process, capital cost overruns, labor shortages, energy price fluctuations, and supply interruptions all weigh on the feasibility of the project.

The immense cost and scope of the project make it far more sensitive to risk than a smaller project. The risk of state and local government increasing the governmental share of project revenue after project sanction must be significantly reduced. There must be enough certainty provided to the sponsors to induce the large investment required. Accordingly, the parties intend to:

- Establish the binding fiscal and other obligations of the project and the participants to the state and municipalities for the term of the contract.
- Protect the project and the participants during the term of the contract from governmental actions and laws that would adversely affect negotiated terms and conditions.

The fiscal terms are established in advance with as much certainty as the Constitution of the State of Alaska allows. Art. IX, § 1 of the Alaska Constitution states that, "The power of taxation shall never be surrendered. This power shall not be suspended or contracted away, except as provided in this article." The attorney general advises that the framers meant the power to tax should never be surrendered, but may be limited by contract under exemptions that may be established by the legislature by general law, for the purpose of providing investment incentives to industry.

For the reasons set out above, it is determined that the long term fiscal interest of the state will be served by providing fiscal certainty for the period provided in the contract. However, for the terms of the contract to conform to law, the legislature must amend the SGDA in the manner described in Section 8. As a result, this determination is conditioned upon subsequent amendment of the SGDA.

9.2.3.3 Maximize Benefits

> *"Maximize the benefit to the people of the State of the development of the State's stranded gas resources."*

The state stands to benefit in several ways from the development of the state's stranded gas resources. The project would create employment opportunities for state residents, generate income for businesses in the state, provide income to state and municipal governments, provide in-state access to ANS gas for homes, business, electric utilities and industrial plants, and create another significant long-term industry in Alaska. This section describes how the contract maximizes each of these benefits.

Create employment and training opportunities for Alaska residents and increase economic opportunities for Alaska businesses

A primary goal of the governor is that Alaskans who want a job on the project have an opportunity to get one. This contract furthers that goal by providing that each project entity operating in the state: (a) employ state residents and contract with businesses in the state to work on construction and operation of the project to the extent these residents and businesses are available, competitively priced and qualified; (b) advertise for available positions in newspapers and other publications throughout the state; (c) use Job Service organizations located throughout the state in order to notify state residents of work opportunities available on the project; (d) work with the state to plan training opportunities for state residents; and (e) incorporate substantially similar obligations in agreements with contractors. Alaska hire policies in the contract deal with prioritizing and maximizing the hiring of state residents during the construction of the portion of the project located in the state, as well as after the commencement of commercial operations.

To further ensure that a maximum number of state residents fill the jobs created by the project, the contract requires the mainline entity to spend or cause the spending of a combined total of $5 million in paying for workforce training programs and activities in the state. Other resources awarded to facilitate workforce development are as follows:

- $20 million committed by the federal government subject to specific provisions as identified in the Energy Bill. This would include $3 million toward an energy industry related training facility in Fairbanks
- $7.5 million awarded to the department of labor from the U.S. Department of Labor for pipeline training and for high growth energy initiative
- Up to $5 million per year from the state Training and Employment Program is given priority for energy related workforce development
- $1.5 million appropriated from the state general fund for a grant to the Alaska Works Partnership for pipeline training equipment

Generate significant state and municipal revenues over the project's life

The contract provides state residents a fair share of revenues from the project. As noted in Sections 4 and 5, gas revenues are about the same under either the contract or the 2005 fiscal terms, with gas revenue being slightly less on a net present value basis. Laying aside the analysis of the old and the new tax regimes, it is important to recognize the basic premise of the contract. There likely would not be a gas line unless the state agrees to terms which increase the profitability of the project. Once commercial operations commence the state will begin to realize substantial new revenues that will help to fill the forecasted revenue shortfall. The production of gas necessarily leads to the production of oil from the same reservoir. The production of this additional oil would further increase future state revenues and extend the life of TAPS and other related oil production property by 20 years or more. These additional oil and gas revenues accruing to the state would be used to support education, health facilities, and other public services for Alaska residents. At least twenty-five percent of the expected revenues from sales of royalty gas would be placed in the Permanent Fund. According to state estimates, this would increase the principal of the Permanent Fund by approximately $2.892 billion for the first ten years of gas line operations starting in 2016 with gas prices at $5.50/mmBtu. At this rate, the earnings to the Permanent Fund would average $250 million a year for the life of the gas line.

The proportion of revenues that state and municipal government will take from the project in royalties and taxes is comparable to that taken by other similar taxing jurisdictions. Based on this comparison, it is determined that the state would be receiving a fair share of project revenue from development of these nonrenewable resources.

Provide opportunities for delivery of gas to domestic and industrial consumers within Alaska

Another important benefit to Alaskans would be access to supplies of low-cost gas. Many areas of the state are not presently served by natural gas utilities, and several potential and current industrial uses could be served by natural gas if the project is developed. This gas could be used for commercial, industrial and residential heating needs as well as for additional electricity generation capacity.

The contract describes the conditions for providing access to natural gas for in-state markets. Prior to the initial open season, in-state needs will be identified by a study completed or adopted by the mainline entity. In consultation with the state, four off-take points in Alaska will be provided by the mainline entity to accommodate in-state gas consumption. Additional off-take points will be provided by the mainline entity as required by FERC. In addition to providing for domestic needs, the sponsor of a LNG project in Southcentral Alaska would have access to these off-take points, consistent with federal law. At the initial and subsequent open seasons, the mainline entity will offer mileage-sensitive rates for transporting gas to the off-take points, consistent with FERC tariff regulations, in order to permit firm contracting of in-state capacity.

It is determined that the contract creates obligations on the parties to provide opportunities for delivery of gas to domestic and industrial consumers within Alaska. The date of first production will determine how soon benefits start accruing. The contract will take effect once it is formally approved by all of the parties: BP, CP, EM, and the state. The contract requires the state and other participants to diligently begin project planning activities not more than 90 days after contract execution. This initial phase of the project planning process culminates in the issuance of certificates of public convenience and necessity by both the FERC and NEB and notification by the mainline entity to the other parties of its decision to proceed with construction of its portion of the project. In addition, every year until the commencement of commercial operations, an amended project plan must be submitted to the state summarizing the work accomplished and expenditures to date and describing the project schedule and proposed development activities. Prior to project sanction, the state may terminate the contract by demonstrating that the participants have not acted with diligence, resulting in a material adverse impact to the project. Prior to the date of project sanction the state can terminate the contract subject to arbitration in case the parties do not diligently pursue the work commitments.

Based on the foregoing, It is determined that the contract will maximize the benefit to the people of the state by development of the state's stranded gas resources in a timely and orderly manner.

Therefore, in consideration of the above findings and determinations and to satisfy the duties conferred on me by AS 43.82.400, I determine that the proposed contract terms are in the long-term fiscal interests of the State of Alaska and further the purposes of AS 43.82, as proposed for amendment.

William A. Corbus

William A. Corbus May 10, 2006

Commissioner

Department of Revenue

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