Appendices

Appendix A

Alaska Stranded Gas Development Act

Chapter 43.82. ALASKA STRANDED GAS DEVELOPMENT ACT

Article 01. CONTRACTS FOR PAYMENTS IN LIEU OF OTHER TAXES

Sec. 43.82.010. Purpose.

The purpose of this chapter is to

(1) 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;

(2) 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

(3) maximize the benefit to the people of the state of the development of the state's stranded gas resources.

Sec. 43.82.020. Contracts for payments in lieu of other taxes and for royalty adjustments.

The commissioner may, under this chapter, negotiate terms for inclusion in a proposed contract with a qualified sponsor or qualified sponsor group providing for

(1) periodic payment in lieu of one or more taxes that otherwise would be imposed by the state or a municipality on the qualified sponsor or members of the qualified sponsor group as a consequence of the sponsor's or group's participation in an approved qualified project under this chapter; and

(2) certain adjustments regarding royalty under AS 43.82.220 .

Article 02. QUALIFICATION AND APPLICATION PROCEDURES

Sec. 43.82.100. Qualified project.

Based on information available to the commissioner, the commissioner may determine that a proposal for new investment is a qualified project under this chapter if the project

(1) principally involves

(A) the transportation of natural gas by pipeline to one or more markets, together with any associated processing or treatment;

(B) the export of liquefied natural gas from the state to one or more other states or countries; or

(C) 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;

(2) would produce at least 500,000,000,000 cubic feet of stranded gas within 20 years from the commencement of commercial operations; and

(3) is capable, subject to applicable commercial regulation and technical and economic considerations, of making gas available to meet the reasonably foreseeable demand in this state for gas within the economic proximity of the project.

Sec. 43.82.110. Qualified sponsor or qualified sponsor group.

The commissioner may determine that a person or group is a qualified sponsor or qualified sponsor group if the person or a member of the group

(1) 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

(2) meets one or more of the following criteria:

(A) owns a working interest in at least 10 percent of the stranded gas proposed to be developed by a qualified project;

(B) has the right to purchase at least 10 percent of the stranded gas proposed to be developed by a qualified project;

(C) has the right to acquire, control, or market at least 10 percent of the stranded gas proposed to be developed by a qualified project;

(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.

Sec. 43.82.120. Applications.

(a) A qualified sponsor or qualified sponsor group may submit to the department an application for development of a contract under AS 43.82.020 evidencing that the requirements of AS 43.82.100 and 43.82.110 are met. The application must be submitted in the manner and form and contain the information required by the department.

(b) Along with an application submitted under (a) of this section, an applicant shall submit a proposed project plan for a qualified project that contains the following information based on the information known to the applicant at the time of application:

(1) a description of the work accomplished as of the date of the application to further the project;

(2) a schedule of proposed development activity leading to the projected commencement of commercial operations of the project;

(3) a description of the development activity proposed to be accomplished under the proposed project plan;

(4) 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;

(5) 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;

(6) a detailed description of options to mitigate the increased demand for public services and other negative effects caused by the project;

(7) a detailed description of options for the safe management and operation of the project once it is constructed;

(8) other information that the commissioner of revenue, in consultation with the commissioner of natural resources, considers necessary to make a determination that

(A) 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;

(B) 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

(C) 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.

(c) The requirements of (b) of this section do not diminish the obligations of a qualified sponsor or member of a qualified sponsor group to the state or restrict the authority of the commissioner of revenue or the commissioner of natural resources under any other law or agreement relating to a plan of development for a lease, pool, or unit.

Sec. 43.82.130. Qualified project plan.

A proposed project plan submitted under AS 43.82.120 may be approved as a qualified project plan under AS 43.82.140 if the proposed project plan

(1) reflects a proposal for diligent development of the project on the part of the applicant;

(2) 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

(3) 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.

Sec. 43.82.140. Review of applications and determination of qualifications.

(a) The commissioner shall review an application submitted under AS 43.82.120 to determine whether the provisions of AS 43.82.100 concerning a qualified project and AS 43.82.110 concerning a qualified sponsor or qualified sponsor group have been met. The commissioner may approve an application only if those provisions have been met.

(b) If the commissioner approves an application under (a) of this section, the commissioner and the commissioner of natural resources shall review the proposed project plan submitted with the application to determine whether the provisions of AS 43.82.130 have been met. The commissioner may approve the proposed project plan as a qualified project plan only if the commissioner of natural resources concurs in the approval.

(c) The commissioner shall send to the applicant written notice of and the reasons for the determinations made under (a) and (b) of this section.

Sec. 43.82.150. Actions challenging determinations on applications.

(a) Only an applicant under AS 43.82.120 who is aggrieved by a determination of the commissioner of revenue or the commissioner of natural resources under AS 43.82.140 may seek judicial review of the determination.

(b) The only grounds for judicial review of a determination made under AS 43.82.140 are

(1) failure to follow the qualification and application procedures set out in AS 43.82.100 - 43.82.180; or

(2) abuse of discretion that is so capricious, arbitrary, or confiscatory as to constitute a denial of due process.

Sec. 43.82.160. Multiple applications for similar or competing qualified projects.

Nothing in this chapter prohibits different qualified sponsors or different qualified sponsor groups from submitting applications under AS 43.82.120 relating to similar or competing qualified projects or prohibits the commissioner of revenue or the commissioner of natural resources from reviewing and approving applications and proposed project plans under AS 43.82.140 relating to similar or competing qualified projects.

Sec. 43.82.170. Application deadline.

The commissioner of revenue or the commissioner of natural resources may not act on an application for a contract submitted under AS 43.82.120 unless the application is received by the Department of Revenue no later than March 31, 2005.

Sec. 43.82.180. Withdrawal of applications.

Subject to the terms of a reimbursement agreement under AS 43.82.240 or other agreement with the Department of Revenue, the Department of Natural Resources, the commissioner of revenue, or the commissioner of natural resources affecting the withdrawal of an application, a qualified sponsor or qualified sponsor group may withdraw an application submitted under AS 43.82.120 at any time before the date that the commissioner of revenue submits a contract to the governor under AS 43.82.430 without further obligation under this chapter.

Article 03. CONTRACT DEVELOPMENT

Sec. 43.82.200. Contract development.

If the commissioner approves an application and proposed project plan under AS 43.82.140 , the commissioner may develop a contract that may include

(1) terms concerning periodic payment in lieu of one or more taxes as provided in AS 43.82.210 ;

(2) terms developed under AS 43.82.220 relating to

(A) timing and notice of the state's right to take royalty in kind or in value; and

(B) royalty value;

(3) terms regarding the hiring of Alaska residents and contracting with Alaska businesses under AS 43.82.230 ;

(4) terms regarding periodic payment to, or an equity or other interest in a project for, municipalities under AS 43.82.500 ;

(5) terms regarding arbitration or alternative dispute resolution procedures;

(6) terms and conditions for administrative termination of a contract under AS 43.82.445 ; and

(7) other terms or conditions that are

(A) necessary to further the purposes of this chapter; or

(B) in the best interests of the state.

Sec. 43.82.210. Contract terms relating to payment in lieu of one or more taxes.

(a) If the commissioner approves an application and proposed project plan under AS 43.82.140 , the commissioner may develop proposed terms for inclusion in a contract under AS 43.82.020 for periodic payment in lieu of one or more of the following taxes that otherwise would be imposed by the state or a municipality on the qualified sponsor or member of a qualified sponsor group as a consequence of participating in an approved qualified project:

(1) oil and gas production taxes and oil surcharges under AS 43.55;

(2) oil and gas exploration, production, and pipeline transportation property taxes under AS 43.56;

(3) *[Repealed, Sec. 6 ch 34 SLA 1999].*

(4) Alaska net income tax under AS 43.20;

(5) municipal sales and use tax under AS 29.45.650 - 29.45.710;

(6) municipal property tax under AS 29.45.010 - 29.45.250 or 29.45.550 - 29.45.600;

(7) municipal special assessments under AS 29.46;

(8) a comparable tax or levy imposed by the state or a municipality after June 18, 1998;

(9) other state or municipal taxes or categories of taxes identified by the commissioner.

(b) If the commissioner chooses to develop proposed terms under (a) of this section, the commissioner shall, if practicable and consistent with the long-term fiscal interests of the state, develop the terms in a manner that attempts to balance the following principles:

(1) the terms should, in conjunction with other factors such as cost reduction of the project, cost overrun risk reduction of the project, increased fiscal certainty, and successful marketing, improve the competitiveness of the approved qualified 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 the project sponsors under a wide range of economic conditions, potential project structures, and marketing arrangements;

(3) the state's and affected municipalities' combined share of the economic rent of the approved qualified project under the contract should be relatively progressive; that is, the state's and affected municipalities' combined annual share of the economic rent of the approved qualified project generally should not increase when there are decreases in project profitability, or decrease when there are increases in project profitability;

(4) the state's and affected municipalities' combined share of the economic rent of the approved qualified project under the contract should be relatively lower in the earlier years than in the later years of the approved qualified project;

(5) the terms should allow the project sponsors to retain a share of the economic rent of the approved qualified project that is sufficient to 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 of the approved qualified project, when discounted to present value, under favorable price and cost conditions;

(7) the method for calculating the periodic payment in lieu of certain taxes under the contract should be clear and unambiguous; and

(8) while cost calculations for the approved qualified project under the contract should be based on amounts that closely approximate actual costs, agreed-upon formulas reflecting reasonable economic assumptions should be used if possible to promote administrative certainty and efficiency.

(c) Except as provided in (b) of this section, the commissioner's discretion under this section in developing proposed terms for a contract under AS 43.82.020 is not limited to consideration of the economic rent of the approved qualified project.

Sec. 43.82.220. Contract terms relating to royalty.

(a) Notwithstanding any contrary provisions of AS 38, the commissioner of natural resources, with the concurrence of the commissioner of revenue and the affected parties holding a state lease or unit agreement, may develop proposed terms for inclusion in a contract under AS 43.82.020 that modify the timing and notice provisions of the applicable oil and gas leases and unit agreements pertaining to the state's rights to receive its royalty on gas in kind or in value if

(1) the viability of the approved qualified project depends on long-term gas purchase and sale agreements;

(2) certainty over time regarding the quantity of royalty gas that the state may be taking in kind is needed to secure the long-term purchase and sale agreements;

(3) the specified period of the state's commitment to take its royalty share in value or in kind does not exceed the term of the purchase and sale agreements; and

(4) the modification does not impair the ability of the approved qualified project or the state to meet the reasonably foreseeable demand in this state for gas within economic proximity of the project during the term of the contract developed under AS 43.82.020 .

(b) Notwithstanding any contrary provisions of AS 38, the commissioner of natural resources, with the concurrence of the commissioner of revenue and the affected parties holding a state lease or unit agreement, may develop proposed terms for inclusion in a contract under AS 43.82.020 that establish a valuation method for the state's royalty share of the gas production from an approved qualified project.

(c) The commissioner of revenue shall include any proposed terms relating to royalty developed in accordance with this section in the proposed contract under AS 43.82.400 .

(d) Nothing in this chapter permits modification of the state's rights that relate to timing, notice, and rights to receive oil royalty in kind or in value under oil and gas leases or unit agreements.

Sec. 43.82.230. Contract terms relating to hiring of Alaska residents and contracting with Alaska businesses.

(a) The commissioner shall include in a contract under AS 43.82.020 a term requiring the qualified sponsor or qualified sponsor group and contractors of the qualified sponsor or qualified sponsor group to comply with all valid federal, state, and municipal laws relating to hiring Alaska residents and contracting with Alaska businesses to work in the state on the approved qualified project and not to discriminate against Alaska residents or Alaska businesses. Within the constraints of law, the commissioner shall also include in a contract under AS 43.82.020 a term that requires the qualified sponsor or qualified sponsor group and contractors of the qualified sponsor or qualified sponsor group to employ Alaska residents and to contract with Alaska businesses to work in the state on the approved qualified project to the extent the residents and businesses are available, competitively priced, and qualified.

(b) The commissioner shall include in a contract under AS 43.82.020 a term requiring the qualified sponsor or qualified sponsor group and contractors of the qualified sponsor or qualified sponsor group to

(1) advertise for available positions in newspapers in the location where the work is to be performed and in other publications distributed throughout the state, including in rural areas; and

(2) use Alaska job service organizations located throughout the state and not just in the location where the work is to be performed in order to notify Alaskans of work opportunities on the approved qualified project.

(c) Subject to the voluntary agreement of the qualified sponsor, the commissioner may include a term in the contract providing for incentives to encourage training and hiring of Alaska residents.

(d) This section does not create or abridge individual rights and does not create a private right of action for any person.

(e) For purposes of this section,

(1) "Alaska business" means a firm or contractor that

(A) has held an Alaska business license for the preceding 12 months;

(B) maintains, and has maintained for the preceding 12 months, a place of business in the state that competently and professionally deals in supplies, services, or construction of the nature required for the approved qualified project; and

(C) is

(i) a sole proprietorship and the proprietor is an Alaska resident;

(ii) a partnership and more than 50 percent of the partnership interest is held by Alaska residents;

(iii) a limited liability company and more than 50 percent of the membership interest is held by Alaska residents;

(iv) a corporation that has been incorporated in the state or is authorized to do business in the state; or

(v) a joint venture and a majority of the venturers qualify as Alaska businesses under this paragraph;

(2) "Alaska job service organizations" means those offices maintained by the state and recommended by the Department of Labor and Workforce Development whose functions are to aid the unemployed or underemployed in finding employment;

(3) "Alaska resident" means a natural person who

(A) receives a permanent fund dividend under AS 43.23; or

(B) is registered to vote under AS 15 and qualifies for a resident fishing, hunting, or trapping license under AS 16;

(4) "available," as applied to an Alaska resident or Alaska business, means that the resident or business is available for employment at the time required and is located anywhere in the state, not just in the area of the state where the work is to be performed;

(5) "qualified," as applied to an Alaska resident or Alaska business, means that the resident or business possesses the requisite education, training, skills, certification, or experience to perform the work necessary for a particular position or to perform a particular service.

Sec. 43.82.240. Use of an independent contractor.

(a) The commissioner may use independent contractors to assist in the evaluation of an application or in the development of contract terms under AS 43.82.200 . The commissioner may condition the development of a contract under AS 43.82.020 on an agreement by the applicant to reimburse the state for the reasonable expenses of independent contractors under this section. A reimbursement of expenses that is required in an agreement authorized by this subsection may not exceed $1,500,000 for each application.

(b) An independent contractor selected under this section must sign an agreement regarding confidentiality and disclosures consistent with the determinations made under AS 43.82.310 before the contractor may review information that is determined confidential under AS 43.82.310 .

(c) Selection of an independent contractor under this section is not subject to AS 36.30 (State Procurement Code).

Sec. 43.82.250. Term of contract; effective date.

The term of a contract developed under AS 43.82.020 may be for no longer than is necessary to develop the stranded gas that is subject to the contract; however, the term of the contract may not exceed 35 years from the commencement of commercial operations of the approved qualified project.

Sec. 43.82.260. Change of parties to an application or a contract; assignment of interests.

(a) A qualified sponsor or member of a qualified sponsor group may assign an interest in or add or withdraw a party to an application under AS 43.82.120 only if the commissioner has

(1) made a finding that the assignment, addition, or withdrawal is consistent with the requirements of AS 43.82.110 ; and

(2) given prior written approval for the assignment, addition, or withdrawal.

(b) A contract developed under this chapter may provide for the assignment to or withdrawal of a qualified sponsor or member of a qualified sponsor group.

(c) Upon being added to an application under this section, a party becomes a qualified sponsor or a member of a qualified sponsor group, as appropriate, for the relevant project.

(d) The commissioner may not unreasonably withhold approval under (a) of this section, but may condition the approval in any way reasonably necessary to protect the fiscal interests of the state and to further the purposes of this chapter.

(e) For purposes of this section, an assignment includes a transfer of stock or a partnership interest in a manner that changes control of a qualified sponsor or member of a qualified sponsor group.

Sec. 43.82.270. Project plans and work commitments.

A contract under AS 43.82.020 must include the qualified project plan approved under AS 43.82.140 and provisions for updating the plan at reasonable intervals until the commencement of commercial operations of the approved qualified project. The commissioner of revenue, in consultation with the commissioner of natural resources, may, as a term in a contract under AS 43.82.020 , include work commitments or other obligations in the contract to be accomplished before the commencement of commercial operations of the approved qualified project.

Article 04. REQUESTS FOR INFORMATION; CONFIDENTIALITY; DISCLOSURE OF INFORMATION

Sec. 43.82.300. Requests for information.

The commissioner of revenue or the commissioner of natural resources may request from an applicant information that the respective commissioner determines is necessary to perform the respective commissioner's responsibilities under AS 43.82.140 . If the application is approved under AS 43.82.140 , the respective commissioner shall require the successful applicant to provide financial, technical, and market information regarding the qualified project that the respective commissioner determines is necessary for the purpose of developing contract terms for the qualified project under AS 43.82.200 . If requested information is not provided, the commissioner of revenue may not continue to review the application under AS 43.82.140 or develop the contract under AS 43.82.200 - 43.82.270, as applicable.

Sec. 43.82.310. Disclosure of information; confidentiality.

(a) An applicant may request confidential treatment of information that the applicant provides under AS 43.82.300 by clearly identifying the information and the reasons supporting the request for confidential treatment. The commissioner of revenue or the commissioner of natural resources, as appropriate, shall keep the information confidential until the commissioner determines whether the requirements of (b) of this section are met. If the commissioner of revenue or the commissioner of natural resources has not made a determination under (b) of this section within 14 days after receiving a request for confidential treatment, the request is considered denied. If the appropriate commissioner determines that the information does not meet the requirements of (b) of this section or if the commissioner fails to make a determination within 14 days, the commissioner shall return the information and any copies of it at the request of the applicant. If the commissioner of revenue or the commissioner of natural resources, as appropriate, returns information under this subsection, the commissioner shall cease review of the application or cease contract development under AS 43.82.200 - 43.82.270, as appropriate, unless the commissioner determines that the returned information is unnecessary to make a determination on the application or to develop contract terms under AS 43.82.200 - 43.82.270.

(b) If requested by the applicant, information provided to the commissioner of revenue or the commissioner of natural resources under AS 43.82.300 shall be kept confidential if the commissioner receiving the information determines, upon an adequate showing by the applicant, that the information

(1) is a trade secret or other proprietary research, development, or commercial information that the applicant treats as confidential;

(2) affects the applicant's competitive position; and

(3) has commercial value that may be significantly diminished by public disclosure or that public disclosure is not in the long-term fiscal interests of the state.

(c) Information determined to be confidential under (b) of this section is confidential under that subsection only so long as is necessary to protect the competitive position of the applicant, to prevent the significant diminution of the commercial value of the information, or to protect the long-term fiscal interests of the state. The commissioner of revenue or the commissioner of natural resources, as appropriate, may not release information that the commissioner has previously determined to be confidential under (b) of this section without providing the applicant notice and an opportunity to be heard.

(d) Notwithstanding the limitation in (c) of this section, the Department of Revenue and the Department of Natural Resources may provide to one another, to the Department of Law, to the legislature, and to the Office of the Governor any information provided under AS 43.82.300 relevant to the implementation of this chapter or to the enforcement of state or federal laws. Information that is exchanged under this subsection that was determined to be confidential under (b) of this section remains confidential except as provided in (c) of this section. The portions of the records and files of the Department of Revenue, the Department of Natural Resources, the Department of Law, the legislature, and the Office of the Governor that reflect, incorporate, or analyze information that is determined to be confidential under (b) of this section are not public records except as provided in (c) of this section.

(e) Notwithstanding the limitation in (c) of this section, information that is determined to be confidential under (b) of this section shall be disclosed on request by the commissioner of revenue, the commissioner of natural resources, or the attorney general to a legislator; to the legislative auditor; and, as directed by the chair or vice-chair of the Legislative Budget and

Audit Committee, to the director of legislative finance, to the permanent employees of those divisions who are responsible for evaluating a contract under AS 43.82.020, and to agents or contractors of the legislative auditor or the director of legislative finance who are engaged to evaluate a contract under AS 43.82.020 . Information that is determined to be confidential under (b) of this section may also be disclosed by the commissioner of revenue or the commissioner of natural resources to an independent contractor under AS 43.82.240 or to a municipal advisory group established under AS 43.82.510 . Before confidential information is disclosed under this subsection, the person receiving the information must sign an appropriate confidentiality agreement.

(f) If the commissioner of revenue chooses to develop a contract under AS 43.82.020 , the portions of the records and files of the Department of Revenue, the Department of Natural Resources, the Department of Law, and a municipal advisory group established under AS 43.82.510 that reflect, incorporate, or analyze information that is relevant to the development of the position or strategy of the commissioner of revenue, the commissioner of natural resources, or the attorney general with respect to a particular provision that may be incorporated into the contract are not public records until the commissioner of revenue gives public notice under AS 43.82.410 of the commissioner's preliminary findings and determination under AS 43.82.400 . Nothing in this subsection

(1) makes a record or file of the Department of Revenue, the Department of Natural Resources, or the Department of Law a public record that otherwise would not be a public record under AS 40.25.100 - 40.25.220;

(2) affects the confidentiality provisions of (a) - (e) of this section; or

(3) abridges a privilege recognized under the laws of this state, whether at common law or by statute or by court rule.

Article 05. CONTRACT REVIEW, APPROVAL, AND TERMINATION

Sec. 43.82.400. Preliminary findings and determination regarding the contract.

(a) If the commissioner develops a proposed contract under AS 43.82.200 - 43.82.270, the commissioner shall

(1) make preliminary findings and a determination that the proposed contract terms are in the long-term fiscal interests of the state and further the purposes of this chapter; and

(2) prepare a proposed contract that includes those terms and shall submit the contract to the governor.

(b) To make the preliminary findings and determination required by (a)(1) of this section, the commissioner shall compare the projected public revenue anticipated from the approved qualified 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 approved qualified project. The commissioner shall address the reasonably foreseeable effects of the proposed contract on the public revenue.

(c) In conjunction with the making of preliminary findings and determination required by (a)(1) of this section, the commissioner shall describe 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 made under (a)(1) of this section is based. If the commissioner has previously submitted a proposed contract to the governor, the commissioner shall describe any material differences between the terms of the currently proposed contract and the previously proposed contract.

Sec. 43.82.410. Notice and comment regarding the contract.

The commissioner shall

(1) give reasonable public notice of the preliminary findings and determination made under AS 43.82.400 ;

(2) make copies of the proposed contract, the commissioner's preliminary findings and determination, and, to the extent the information is not required to be kept confidential under AS 43.82.310 , the supporting financial, technical, and market data, including the work papers, analyses, and recommendations of any independent contractors used under AS 43.82.240 available to the public and to

(A) the presiding officer of each house of the legislature;

(B) the chairs of the finance and resources committees of the legislature; and

(C) the chairs of the special committees on oil and gas, if any, of the legislature;

(3) offer to appear before the Legislative Budget and Audit Committee to provide the committee a review of the commissioner's preliminary findings and determination, the proposed contract, and the supporting financial, technical, and market data; if the Legislative Budget and Audit Committee accepts the commissioner's offer, the committee shall give notice of the committee's meeting to the public and all members of the legislature; if the financial, technical, and market data that is to be provided must be kept confidential under AS 43.82.310 , the commissioner may not release the confidential information during a public portion of a committee meeting; and

(4) establish a period of at least 30 days for the public and members of the legislature to comment on the proposed contract and the preliminary findings and determination made under AS 43.82.400 .

Sec. 43.82.420. Coordination of public and legislative review.

To the extent practicable, the commissioner shall coordinate the public comment opportunity provided under AS 43.82.410 (4) with a review by the Legislative Budget and Audit Committee under AS 43.82.410 (3).

Sec. 43.82.430. Final findings, determination, and proposed amendments; execution of the contract.

(a) Within 30 days after the close of the public comment period under AS 43.82.410 (4), the commissioner of revenue shall

(1) prepare a summary of the public comments received in response to the proposed contract and the preliminary findings and determination;

(2) after consultation with the commissioner of natural resources, if appropriate, and with the pertinent municipal advisory group established under AS 43.82.510 , prepare a list of proposed amendments, if any, to the proposed contract that the commissioner of revenue determines are necessary to respond to public comments;

(3) make final findings and a determination as to whether the proposed contract and any proposed amendments prepared under (2) of this subsection meet the requirements and purposes of this chapter.

(b) After considering the material described in (a) of this section and securing the agreement of the other parties to the proposed contract regarding any proposed amendments prepared under (a) of this section, if the commissioner determines that the contract is in the long-term fiscal interests of the state, the commissioner shall submit the contract to the governor.

(c) The commissioner's final findings and determination under (a) of this section are final agency decisions under this chapter.

Sec. 43.82.435. Legislative authorization.

The governor may transmit a contract developed under this chapter to the legislature together with a request for authorization to execute the contract. A contract developed under this chapter is not binding upon or enforceable against the state or other parties to the contract unless the governor is authorized to execute the contract by law. 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 contract.

Sec. 43.82.440. Judicial review.

A person may not bring an action challenging the constitutionality of a law authorizing a contract enacted under AS 43.82.435 or the enforceability of a contract executed under a law authorizing a contract enacted under AS 43.82.435 unless the action is commenced within 120 days after the date that the contract was executed by the state and the other parties to the contract.

Sec. 43.82.445. Administrative termination of a contract.

(a) The commissioner shall include terms in a contract developed under AS 43.82.020 that provide for administrative termination of a party's rights under the procedures and conditions set out in this section if the party has

(1) ceased to meet the requirements of AS 43.82.110 as a qualified sponsor or qualified sponsor group;

(2) intentionally or fraudulently misrepresented, in whole or in part, material facts or circumstances upon which the contract was made;

(3) failed to comply with a condition or material term of the contract or a provision of this chapter; or

(4) failed to comply with the approved qualified project plan or any updated project plan.

(b) Before administrative termination of a contract under this section, the commissioner shall give notice to the parties of the commissioner's intent to terminate the contract and an opportunity to be heard. The commissioner may also provide the parties an opportunity to cure any deficiency that is the basis for the termination if the commissioner determines that curing the deficiency is appropriate under the circumstances.

(c) Notwithstanding (a) and (b) of this section, the commissioner may not administratively terminate a contract after the party has committed full project funding except as provided in (e) of this section.

(d) A party to a contract who is affected by the commissioner's action to terminate under (a) of this section may file an appeal with the superior court under the Alaska Rules of Appellate Procedure.

(e) The commissioner may provide terms and conditions in a contract developed under AS 43.82.020 upon which a party's rights under the contract may be administratively terminated after the party commits full project funding.

Article 06. MUNICIPAL PARTICIPATION

Sec. 43.82.500. Obligation to share payments with municipalities.

If the commissioner develops a contract under AS 43.82.020 that includes terms that exempt a party to the contract, and the property, gas, products, and activities associated with the approved qualified project that is subject to the contract, from a municipal tax or assessment in accordance with AS 29.45.810 or AS 29.46.010 (b), or AS 43.82.200 and 43.82.210, the commissioner shall include a term in the contract that the party pay a portion of the periodic payments due under the contract to the revenue-affected municipality.

Sec. 43.82.505. Payments to economically affected municipalities.

If the commissioner executes a contract under AS 43.82.020 that will produce one or more economically affected municipalities, the commissioner shall include a term in the contract that provides for a portion of the periodic payments to the economically affected municipalities under the principles in AS 43.82.520 .

Sec. 43.82.510. Municipal advisory group.

(a) If the commissioner approves an application and proposed project plan under AS 43.82.140 and decides to develop a contract under AS 43.82.020 and 43.82.200, the commissioner shall notify each revenue-affected municipality and economically affected municipality.

(b) The mayor of a municipality notified by the commissioner under (a) of this section may appoint one representative to a municipal advisory group in relation to the application.

(c) Each municipal advisory group serves until a final action is taken on the application for which the group was appointed.

(d) Each municipal advisory group shall elect a chair.

Sec. 43.82.520. Duties of the commissioner of revenue in relation to municipal participation.

(a) The commissioner shall meet with each municipal advisory group periodically to report on the development of the contract provisions that affect the municipalities.

(b) In developing a contract under AS 43.82.200 - 43.82.270, the commissioner shall ensure that each revenue-affected municipality and economically affected municipality receives a fair and reasonable share of the payments provided under AS 43.82.210 in accordance with the following principles:

(1) the share of the payments to revenue-affected municipalities should be given priority over payments to economically affected municipalities with due regard to the anticipated size of the tax base that the contract would exempt from municipal taxation by revenue-affected municipalities;

(2) the share of the payments to municipalities should be determined with due regard to the anticipated economic and social burdens that would be imposed on the municipality by construction and operation of the project;

(3) the respective shares of the total payments to the state and to municipalities should be fixed in a manner to ensure that their respective interests are aligned;

(4) to the extent practicable, the periodic amounts paid to each of the municipalities should be stable and predictable; and

(5) to the extent practicable, the provisions for sharing payments with municipalities should be consistent with the principles established in AS 43.82.210 (b).

(c) In establishing the municipal shares under (b) of this section, the commissioner shall consult with the pertinent municipal advisory group.

Sec. 43.82.600. Governing law.

If a provision of this chapter conflicts with another provision of state or municipal law, the provision of this chapter governs.

Sec. 43.82.610. Regulations.

The commissioner of revenue, the commissioner of natural resources, and the commissioner of labor and workforce development may adopt regulations to carry out their respective duties under this chapter.

Sec. 43.82.620. Procedures for collection of amounts due; security.

(a) The commissioner may adopt procedures for the collection of amounts due the state under a contract developed under AS 43.82.020 , including the collection of interest and penalties.

(b) The commissioner may require a party to a contract developed under AS 43.82.020 to provide security sufficient to guarantee amounts due under the contract.

Sec. 43.82.630. Reports and audits.

The commissioner may require periodic reports from and may at reasonable intervals conduct audits and inspect the books of a party that has entered into a contract developed under AS 43.82.020 to ensure compliance with the provisions of this chapter and the regulations adopted under this chapter and of the terms of the contract.

Sec. 43.82.640. Annual report of the commissioner of labor and workforce development.

On an annual basis, the commissioner of labor and workforce development shall prepare and present to the legislature a comprehensive report on each party to a contract with the state developed under AS 43.82.020 , and its contractors, regarding the state residency of the employees working in this state on the approved qualified project that is subject to the contract. The commissioner of labor and workforce development shall use state data bases, including data from the quarterly reports by a party to the contract developed under AS 43.82.020 and its contractors for unemployment insurance purposes, to determine state residency of employees regarding compliance with AS 43.82.230 .

Article 08. GENERAL PROVISIONS

Sec. 43.82.900. Definitions.

In this chapter, unless the context requires otherwise,

(1) "affected municipality" means an economically affected municipality or a revenue-affected municipality;

(2) "commencement of commercial operations" means the start of regular deliveries of marketable products from an approved qualified project;

(3) "cubic foot of gas" means the quantity of gas contained in a volume of one cubic foot at a standard temperature of 60 degrees Fahrenheit and a standard absolute pressure of 14.65 pounds per square inch;

(4) "economically affected municipality" means a municipality the commissioner of revenue determines will be reasonably required to provide additional public services under the terms proposed in an application approved under AS 43.82.140 (a); the commissioner may consider historical data from construction of the Trans Alaska Pipeline System, and information submitted by a municipality in making the determination;

(5) "economic proximity" means the distance within which a person may be willing to design, construct, and operate a gas line to provide service to a local consumer;

(6) "economic rent" means the estimated total gross revenue less estimated total costs for a qualified project over the term of a contract under AS 43.82.020 , measured in undiscounted nominal dollars; for purposes of this paragraph, total costs do not include a rate of return on capital, financing costs, or any payments to governments;

(7) "full project funding" means full approval by a party to a contract under AS 43.82.020 for the expenditure of the capital necessary for construction and operation of the approved qualified project that is subject to the contract;

(8) "gas" has the meaning given in AS 43.55.900 ;

(9) "group" means two or more persons;

(10) "lease or property" has the meaning given in AS 43.55.900 ;

(11) "periodic payment" means payment made in lieu of one or more other taxes under a contract under AS 43.82.020 ;

(12) "revenue-affected municipality" means a municipality that the commissioner of revenue reliably expects will be restricted from imposing a tax, or a portion of a tax, as a result of implementation of a contract developed under this chapter;

(13) "stranded gas" means gas that is not being marketed due to prevailing costs or price conditions as determined by an economic analysis by the commissioner for a particular project.

Sec. 43.82.990. Short title.

This chapter may be cited as the Alaska Stranded Gas Development Act.

Appendix B

Validity of Application and Project Plan

STATE OF ALASKA

DEPARTMENT OF REVENUE

OFFICE OF THE COMMISSIONER

FRANK H. MURKOWSKI, GOVERNOR

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January 23, 2004

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Re: Application under the Alaska Stranded Gas Development Act

Dear Gentlemen:

ConocoPhillips Alaska Inc., BP Exploration (Alaska), Inc., and ExxonMobil Alaska Production, Inc. (the "Sponsors") have submitted an application and proposed project plan to the State under the Stranded Gas Development Act for a pipeline that would transport natural gas from the Alaska North Slope through Alaska to markets in Canada and the Lower 48 United States.

The Sponsors' application identifies two of the possible routes to bring Alaska North Slope stranded gas resources to market. One route would generally follow the TAPS route and then the Alaska Canadian highway through Canada and into Alberta (the Highway Route). The second pipeline route would cross state land in or adjacent to the

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Beaufort Sea off the north coast of Alaska and then proceed east to the Mackenzie River valley and south to Alberta (the Over-the-Top Route).

Both the Over-the-Top Route and the Highway Route are potentially qualified projects under the Stranded Gas Development Act. Nevertheless, the Over-the-Top Route is inconsistent with current state law. The Right-of-Way Leasing Act currently prohibits the Department of Natural Resources from issuing a lease across state land for the Over-the-Top Route (AS 38.35.017).

The State has reviewed the materials submitted by the Sponsors and finds that the Sponsors are qualified sponsors under the Act and that the application and proposed project plan are sufficient under the Act. Therefore the State hereby approves the Sponsors' application and proposed project plan. The State acknowledges that no final commercial decision has been made on any route and the State intends to fully discuss all aspects of the permitable, qualified project consistent with the application submission. The State intends to negotiate with the Sponsors concerning all aspects of the application and proposed project plan.

The State looks forward to the next stage of the process and working with the Sponsors to develop a mutually acceptable contract.

STATE OF ALASKA
DEPARTMENT OF REVENUE

William A. Corbus

William A. Corbus, Commissioner

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES

Tom Irwin, Commissioner

cc: Governor Frank H. Murkowski
James F. Clark, Chief of Staff
Gregg D. Renkes, Attorney General

January 23, 2004
Marushack, Konrad, Schilahab
Appl'n Under Staranded Gas Act

Validity of Application and Project Plan

The submittal of an application and proposed project plan by a sponsor or sponsor group is the initial step toward the fiscal contract development process. Based on the information available in the application and project plan, the state determines if a project, sponsor or sponsor group, and project plan are qualified under the criteria in the SGDA.

The producers group submitted an application, including a proposed project plan, for development of a fiscal contract under the SGDA on January 20, 2004. The statement of qualifications of the project and sponsor group and the proposed project plan, as described in the "Amended Application for Development of a Contract under AS 43.82, the Alaska Stranded Gas Development Act," are summarized below.

Qualified Project

Under AS 43.82.100, three criteria must be met in order for the state to determine that a project is qualified under the SGDA. The three criteria are: commercialization, production threshold, and in-state demand, and are summarized below.

Commercialization

Under subsection AS 43.82.100(1), a project is qualified if it principally involves (A) the transportation of natural gas by pipeline to one or more markets, together with any associated processing or treatment; (B) the export of liquefied natural gas from the state to one or more other states or countries; or (C) 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.

The project described in the producers group's application involves the transportation of natural gas by pipeline to one or more markets, together with any associated processing or treatment; therefore, the project meets this criterion. The project consists of four major components—a GTP, a pipeline from Alaska to Alberta, a potential NGL plant, and a potential pipeline from Alberta to Chicago.

The GTP would be located on the North Slope and would be designed to remove impurities from the natural gas stream to meet inlet pipeline specifications. These pipeline specifications would also require that the gas be compressed and chilled. The pipeline design consists of 52-inch buried pipe operating at approximately 2,500 pounds per square inch (psi). Compressor stations would be placed at regular intervals.

An 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. An NGL Plant may be a newly constructed facility or an existing facility. A new-build plant could theoretically be located anywhere along the pipeline route.

The final portion of the project involves the export of gas from Alberta. Export alternatives from Alberta include utilizing existing pipeline capacity made available by anticipated declines in existing Canadian gas production, expansion of existing pipeline systems, or installation of other new-build pipeline concepts.

Production Threshold

AS 43.82.100(2) establishes a production threshold of at least 500,000,000,000 (500 billion) cubic feet of gas within 20 years from the commencement of commercial operations

The project described in the producers group's application would produce significantly more than 500 bcf within 20 years from the commencement of commercial operations; therefore, the project meets this criterion. The producers group has developed a preliminary plan to build a natural gas pipeline and related facilities which would have a design capacity to transport approximately 4 bcf/d of stranded gas to markets in Canada and the Lower 48 States. If this capacity were achieved, the project would produce over 500 billion cubic feet of stranded gas within the first year of commercial operations, even with the expected volume ramp up during the first months after gas begins to flow.

In-state Demand

Under AS 43.82.100(3) a qualified project must be 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

The project described in the producers group's application is capable of making gas available to meet the foreseeable demand for gas in Alaska, within the economic proximity of the project; therefore, the project meets this criterion. The producers group recognizes the strong interest in making gas available for in-state use. The producers group plans to work cooperatively with potential downstream investors and the state in a way that is consistent with the well-established regulatory framework of fair and open access. Consistent with this regulatory framework, gas can be made available for in-state use under reasonable terms and conditions. The producers group's proposed project plan describes the principles under which natural gas may be made available. The four principles are listed in Section 3.3.3.

Qualified Sponsor or Sponsor Group

Two criteria must be met in order for the state to determine that a sponsor or sponsor group is qualified under the SGDA. The two criteria are described in the following subsection headings.

Commitment

Under 43.82.110(1) a person or group can be deemed qualified if they intend to own an equity interest in a qualified project, intend to commit gas that is owned to a qualified project, or hold the permits that the department determines are essential to construct and operate a qualified project

The producers group will own an equity interest in the project; therefore, the producers group meets this criterion. In addition, the members of the producers group expect as individual companies, either directly, through affiliates, or through affiliated interests in subsequently created legal entities, to commit their gas to the project.

Resources

AS 43.82.110(2) states that a person or group can be qualified if they meet one or more of the following criteria: 1) Owns at least 10 percent of the gas proposed to be developed; 2) Has a right to purchase at least 10 percent of the gas proposed to be developed; 3) Has a right to acquire, control, or market at least 10 percent of the gas proposed to be developed; 4) Has a net worth of at least 10 percent of the estimated cost of constructing the project; and/or 5) Has an unused line of credit equal to at least 15 percent of the estimated cost of constructing the project.

The producers group owns at least 10 percent of the gas proposed to be developed; therefore, the sponsor group meets this criterion. The producers group, as owners in both the Prudhoe Bay and Point Thomson gas resources, holds a working interest in approximately 32 tcf of North Slope stranded gas; taking out the state's royalty share, this amount represents a net share of approximately 29 tcf. Several assumptions must be made about the project to determine the producers group's share of the total volume of gas to be delivered by the project. Assuming sufficient natural gas supplies are developed to fill a 4 bcf/d design capacity for 35 years, approximately 50 tcf of stranded gas would be delivered to the market by the pipeline project. As such, the producers group would have interest in over 60 percent of the total stranded gas assumed to be produced, well in excess of the 10 percent gas resource access requirement for qualified sponsors.

Either directly or through affiliates, the members of the producers group are also owners in other North Slope fields containing additional natural gas resources, including the Alpine, Endicott, Milne Point, and Northstar fields, as well as other undeveloped leases. Furthermore, the producers group has the potential to secure new leases and successfully discover and develop additional gas resources

Qualified Project Plan

Under AS 43.82.130, three criteria must be met in order for the state to determine that the proposed project plan is qualified under the SGDA. The three criteria are described in the following subsection headings.

Diligent Development

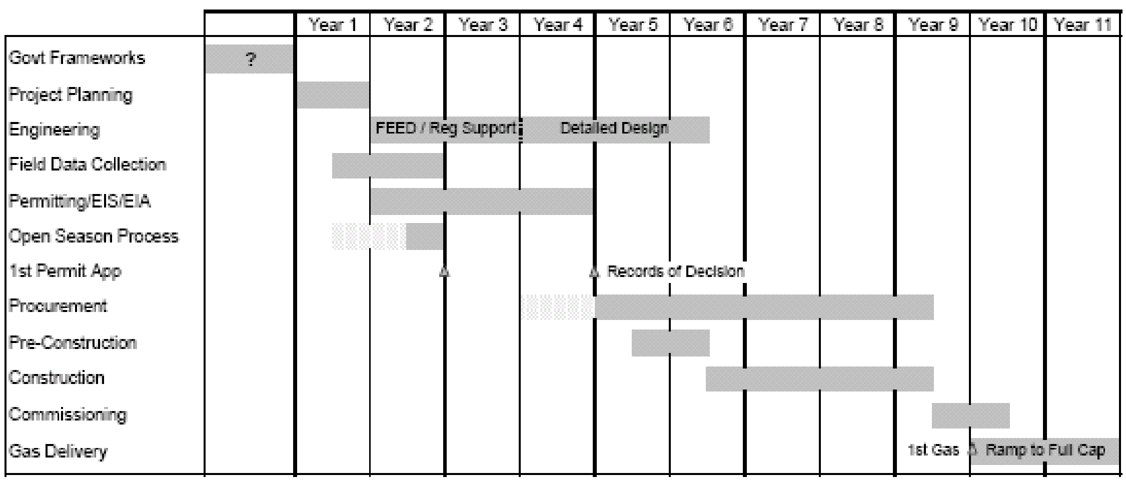
The proposed project plan submitted with the producers group's application reflects a proposal for diligent development of the project on the part of the applicant as required by AS 43.82.130(1); therefore, the proposed project plan meets this criterion. The work accomplished by the producers group prior to submitting an application under the SGDA includes a $125 million study conducted in 2001 and 2002 to assess the feasibility of constructing a pipeline to deliver Alaska gas to Canadian and Lower 48 markets. The study assessed the cost, technology, regulatory, and environmental issues associated with the project. The major system components considered include a GTP, an Alaska to Alberta pipeline system, a potential NGL Plant, and a potential Alberta to Lower 48 pipeline system.

Following the conclusion of the 2001-02 joint study, the primary focus of activity for the producers group shifted to addressing key areas of risk identified in the study. Specific joint activities to develop the necessary government frameworks have included pursuit of U.S. Federal enabling legislation, and support of the reauthorization of the SGDA in Alaska. Further joint technical work also continued, including the evaluation of various cost reduction ideas such as field trials of high efficiency trenching machines and evaluation of potential transportation infrastructure improvements.

The figure reproduced below presents a conceptual timeline for planning and constructing the natural gas pipeline and related facilities. Following the establishment of suitable government frameworks (such as this SGDA process), the overall timeline spans ten years, beginning with project planning, and ending with mechanical completion and commissioning. The schedule assumes that project funding, which triggers the initiation of major equipment procurement and module fabrication, would be contingent on receiving key government approvals (i.e., Records of Decision). The current project timeline assumes that each milestone will be successfully completed. However, if issues do arise, the schedule would be extended accordingly.

Figure 1. Conceptual Project Timeline

Figure 5.3(1) Conceptual Project Timeline



Source: "Amended Application for Development of a Contract under AS 43.82, the Alaska Stranded Gas Development Act" prepared by British Petroleum (Alaska), Inc., ConocoPhillips Alaska, Inc., and ExxonMobil Alaska Production, Inc.

Conflict with Obligations to State

The proposed project plan submitted with the producers group's application 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 as noted under AS 43.82.130(2); therefore, the proposed project plan meets this criterion. While the proposed project plan anticipates a fiscal contract that provides "fiscal simplicity and clarity" for the producers group's gas and leases, it does not by itself contain any express proposals that conflict with the producers group's current lease or unit obligations. Nothing in the plan conflicts with the producers group's representation that "unless and until provided otherwise in a contract under this application, all existing obligations shall continue to be governed by existing leases and unit agreements with the State."

3.3.3 In-state Demand

The proposed project plan submitted with the producers group's application describes satisfactory methods and terms for accommodating reasonably foreseeable demand for gas in the state as required under AS 43.82.130(3); therefore, the proposed project plan meets this criterion. The producers group plans to work cooperatively with potential downstream investors (e.g., local distribution companies, industrial users, marketers, and utilities) and the state in a way that is consistent with the well-established regulatory framework of fair and open access. This should put these prospective customers and the state in a position to satisfy reasonably foreseeable local gas demand within economic proximity of the pipeline project during the term of the contract. The producers group lists the following principles under which natural gas may be made available.

- The producers group would work with potential downstream investors and the state to identify pipeline connection locations along the pipeline that correspond with reasonably foreseeable in-state demand that is within economic proximity of the pipeline.
- Potential downstream investors would have an opportunity to negotiate gas purchase contracts with any party holding title to gas, (i.e., individual producer, marketer or local distribution company, or the State of Alaska).
- Potential downstream investors meeting objective creditworthiness standards would have the opportunity to contract for pipeline capacity on the Alaska Gas Pipeline Project. The allocation of capacity on interstate pipelines is governed by the regulations and policies of the FERC. The initial open season process provides a potential shipper with the ability to secure capacity via a long-term contract for natural gas shipment to its local gas conditioning and distribution infrastructure and ultimate sale to end-users. A similar open season process would be used to identify potential shippers and allocate capacity for any subsequent pipeline expansions. In addition, potential shippers would have the opportunity, subject to FERC regulations, to contract for unused capacity that shippers may release into the secondary market.
- The producers group has no current plans or intent to build or own local gas conditioning and distribution infrastructure (e.g., pressure reduction equipment, calorific control equipment, spur lines, local gas distribution systems, etc.) that may be required to serve in-state demand. Subsequent downstream gas conditioning and distribution infrastructure would be the responsibility of downstream investors.

Letter of Approval

On January 23, 2004, the Commissioner: (a) determined that the proposed project is a qualified project under the SGDA; (b) determined that BP, CP and EM are qualified sponsors under the SGDA; and (c) with the concurrence of the commissioner of ADNR, approved the application and the proposed project plan.

In the letter of approval the Commissioner observes that the producers group's application identifies two of the possible routes to bring Alaska North Slope stranded gas resources to market. One route would generally follow the TAPS route and then the Alaska Canadian highway through Canada and into Alberta (the Highway Route). The second pipeline route would cross state land in or adjacent to the Beaufort Sea off the north coast of Alaska and then proceed east to the Mackenzie River valley and south to Alberta (the Over-the-Top Route). The Commissioner notes in the letter that the Over-the-Top Route is inconsistent with current state law.

The Commissioner also acknowledges that no final commercial decision has been made on any route and indicates that the state intends to fully discuss all aspects of the permitable, qualified project consistent with the application submission.

Appendix C

Is Alaska North Slope Gas Stranded? Economic Analysis and Determination Alaska Department of Revenue

Is Alaska North Slope Gas Stranded?
Economic Analysis and Determination
Alaska Department of Revenue

I. Executive Summary

Natural gas on the Alaska North Slope (ANS) is considered legally "stranded" under AS 43.82 if it is not being marketed, and will not be marketed due to cost and/or price conditions. The vast preponderance of natural gas on the North Slope qualifies under such consideration. This includes both currently produced but recycled gas and gas in fields not yet producing. The economic reasons for stranding consist of high costs of transporting the gas to market [both capital and operating] relative to the uncertain future natural gas price, and the rate of return on the potential investment relative to other options. Additionally, the magnitude of any transportation infrastructure construction project itself is an economic factor that contributes to the conclusion. Eventually, gas producers or others may construct some means to transport North Slope gas to market. However, due to competition from other projects throughout the world which have higher economic returns, the Alaskan project may face years of delay without State fiscal incentives.

II. Introduction

Per the Alaska Stranded Gas Development Act (AS 43.82.900 (13), " 'stranded gas' means gas that is not being marketed due to prevailing costs or price conditions as determined by an economic analysis by the commissioner [of the State of Alaska Department of Revenue] for a particular project." This report constitutes that determination.

For this determination, prevailing value and costs are those for the period of the contract. The Stranded Act states the following in AS 43.82.900 (6): ' "economic rent" means the estimated total gross revenue less estimated total costs for qualified project ***over the term of a contract*** [emphasis added]…' Since the project would not begin for 10 years, and would last 30 or more years, prevailing value and costs are those that are forecast for the next 40 plus years.

Not only are prevailing values and costs important in making the determination, but the rate of return a company would receive under the prevailing values and costs becomes important. Since companies have a portfolio of projects available for investment, the relative rank of the Alaska project, in comparison to other projects in the company's portfolio becomes important in determining if Alaska's gas is stranded.

If gas is determined to be stranded, the State is authorized to establish fiscal terms [related to new investment in advance of project initiation] that would be tailored to the project's particular economic conditions. These terms may provide for payments in lieu of tax payments to offer greater chances of project success while maximizing the benefit to the people of the State.

At the time of enactment of AS 43.82, the Legislature found as a matter of fact that "a vast quantity of gas in Alaska is stranded from commercial development because of the cost associated with providing access to markets for that gas."(§ 3 ch 104 SLA 1998 at Section 1(1)). This analysis reviews events since 1998 in the History section to see if recent events alter this finding.

Three groups submitted projects under the Stranded Gas Development Act and they are the following: [1] the "Sponsor Group" proposal which is the proposal submitted by ConocoPhillips, BP, and ExxonMobil [2] the TC proposal submitted by TransCanada Company [TC] and [3] the AGPA proposal submitted by the Alaska Gas Line Port Authority [AGPA]. The Sponsor Group proposal consists of a pipeline and related facilities that would carry approximately 4 billion cubic feet per day (bcf/d) of natural gas from the Alaska North Slope (ANS) to Alberta and on to North America markets. The TC proposal differs from the Sponsor Group proposal primarily in the ownership of the pipeline. Therefore the Sponsor proposal is analyzed as a proxy for either. The AGPA proposal differs from the first two in that it proposes shipping about 4 bcf/d of liquefied natural gas [LNG] from Valdez. To undertake this requires the construction of a pipeline of approximately 800 miles in length from the North Slope to Valdez, the construction of liquefaction facilities in Valdez, the construction of tankers to transport the LNG, and the construction of re-gasification facilities on the Pacific Coast of North America to receive the LNG and convert it to gas.

This analysis examines the reasons the gas is not being marketed and the reasons that no projects are under construction to market it. The analysis also considers the temporal nature of current and projected market conditions. If it is concluded that ANS natural gas is not being marketed due to prevailing cost or market conditions, then the gas is stranded. The term "prevailing" is interpreted to mean the cost or market conditions during the majority of the period when the gas is expected to be marketed.

III. History

Before 1998, the prospects for commercializing North Slope gas were elusive, owing mainly to low market prices which could not justify the high costs of any project to bring the gas to market. One or more such projects have been under active consideration for more than a quarter century. Recently, however, a number of significant events have occurred that have elevated the prospects for a viable project:

- The increase in US natural gas prices. The continued increase in North America gas demand has pushed up against available supply with the result that natural gas prices began to rise starting in 2000.

- The alignment of interests in the oil rim and the gas cap between the working interest owners at Prudhoe Bay subsequent to BP's purchase of Arco, and subsequent divesting of Arco's interests to ConocoPhillips in 2000.

- The aging of the Prudhoe Bay reservoir is approaching a point where removing, rather than recycling gas from the reservoir, will not materially affect oil recovery by the time a gas project would begin.

- The gas handling facility at Prudhoe Bay has reached its capacity. Any expansion would have limited impact on increasing crude oil production.

- The creation of Federal legislation in 2004 that provides opportunities for loan guarantees and tax benefits for a North Slope gas pipeline project.

In 2001, the Sponsor Group undertook a $125 million North Slope gas pipeline feasibility study. The proposed project plan submitted by the Sponsor Group is the result of that study. The estimated capital cost to build a pipeline and deliver the gas to Chicago, the closest large volume nexus with domestic gas pipelines, is about $21 billion[1].

IV. The Energy Density of Gas

When hydrocarbons such as oil or natural gas are sold, what is really being sold is the energy equivalent content, or British Thermal Units (BTU's). On a volumetric basis, natural gas has much lower BTU density than oil. At standard temperature and pressure, a cubic foot of oil has 1,000,000 BTU's. A cubic foot of gas has only 1,000 BTU's, or 1/1000th as much. This has important implications for the cost of moving gas to market.[2]

A thousand cubic feet (mcf) of gas contains only about 1/6 the amount of BTU's as a barrel of oil. The Trans-Alaska (oil) Pipeline (TAPS) is about 48 inches in diameter and at full capacity can ship about 2 million barrels of oil a day (about 12×10^{12} BTU's). The proposed gas pipeline will be slightly larger, and ship about 4 bcf/d of natural gas (about 4.66×10^{12} BTU's per day). (The gas will be compressed in the pipeline to about 1/170th of its atmospheric volume.) Thus the gas pipeline will only carry about 1/3 the number of BTU's as the oil pipeline. Yet, again, it will be larger, and require extensive compression to place and move the gas within it. The result is that gas is much more expensive to ship than oil.[3] And, the longer the pipeline, the higher the cost to transport the natural gas. This is discussed in detail below.

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[1] The original cost estimate has been updated to 2005 price levels.

[2] A cubic foot of gas at standard temperature and pressure contains about 1,000 BTU's. Due to the specific mixture of products contained within the gas, as is the case with the ANS gas to be transported to market, the BTU content can be higher. The BTU content of ANS marketable gas is projected to increase over time as the average is expected to be about 1,080 BTU per cubic foot.

[3] Two general types of natural gas are produced by drilling, referred to as dry gas and natural gas liquids (NGL). When gas is removed from the ground, it often contains water and other condensates. The water is

V. Natural Gas Supplies and Market

Each type of fuel has specific advantages and disadvantages. These include costs, associated byproducts, infrastructure requirements, specific use characteristics, energy generation factors, and so forth. At least at the present time, a mix of fuels is necessary since there is not enough fuel available from any one source to satisfy all needs worldwide. Therefore, natural gas contributes a significant part of world and domestic fuel supply. Due to many of its characteristics, natural gas is forecast to contribute an even greater percentage of fuel supplies for the foreseeable future[4].

There are 6,000 - 7,000 trillion cubic feet (tcf) of proven natural gas reserves in the world.[5] There are about 40 tcf of natural gas discovered in Alaska of which about 32 tcf are recoverable, most of it on the North Slope.[6] [7] This equates to world reserves the size of about 200 North Slope reserves. Much of this gas worldwide is located at great distances from market. As a result, distance to market and geography have kept much of these reserves out of the market.

While these are proven reserves, there is tremendous potential worldwide for additional natural gas discoveries. In Alaska alone, there is an estimated gas resource potential of more than 200 tcf. This potential resource, regardless of size, is functionally not recoverable until there is a means of transporting it to market.

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separated and reinjected. Natural gas liquids, including ethane, propane, butane and lease condensate, are removed from the mixture and liquefied in a gas processing plant. On the North Slope, a portion of these NGLs are then injected into the TAPS line as part of the oil mixture, with the balance re-injected into the oil fields. Dry gas is composed primarily of methane and is not injectable into the TAPS line. This is the natural gas that is the focus of this analysis.

The weight of a barrel of oil is directly related to its American Petroleum Institute (API) gravity and specific gravity. The heavier the oil, the lower (smaller) its API gravity and the higher its specific gravity. Higher specific gravity relates to a denser substance so oil with a lower API gravity weighs more.

The BTU content of oil also is directly related to its API gravity. The higher the API gravity the more BTU's per weight of oil, however, as weight and BTU content are combined, lower API gravity oil has a higher BTU content per barrel. For example, at standard temperature and pressure, oil of 35° API gravity contains 5.965 million BTU per barrel while oil of 27° API gravity contains 6.096 million BTU per barrel. Since blended oil transported to Valdez has an API gravity within this range, 6 million BTU per barrel is a reasonable approximation.

[4] International Energy Agency, World Energy Outlook 2005, OECD, 2005, page 81.

[5] National Energy Information Center, U.S. Department of Energy at: www.eia.doe.gov/emeu/international/reserves.xls.

[6] Mineral Management Service, 2001 "Prospects For Development of Alaska Natural Gas: A Review" by Kirk W. Sherwood, James D. Craig at: www.eia.dow.gov/emeu/international/gas.html.

[7] Natural Gas Supply Association, Natural gas overview at: www.naturalgas.org/overview/resources.asp.

The major market proposed for Alaskan natural gas is domestic. Natural gas enters the domestic market through pipelines or imported via tanker as liquid natural gas (LNG). Currently, all North American LNG import/re-gasification facilities are located on the east and gulf coasts. While a small number of re-gasification facilities may be built on the west coast, any significant increase in LNG imports there will require additions to the pipeline infrastructure to transport natural gas eastward to market.

Regardless of form, natural gas competes with other energy sources in the broader marketplace. While it is better suited than other fuels for some uses, it is competitive or non-competitive for others. For instance, some utility plants may be built to use only one type of fuel while others may be designed to easily convert between fuel types. Most single fuel plants are convertible to other fuel types including natural gas. The largest current use for natural gas is industrial whereas the major increase in natural gas demand in the foreseeable future is for electric generation.[8]

The Energy Information Administration's (EIA – of the U.S. Department of Energy) energy outlook to 2030 presents a wide range of forecasts for natural gas demand.[9] Their own forecast shows an overall domestic natural gas demand increase of 0.8% per year from 2004 levels. Most of the demand growth will be in electric power generation which will overtake industrial uses as the highest use category. LNG imports are projected to grow at over 8% annualized and by 2030 consist of approximately 16% of domestic dry gas production (gas supplied by pipeline).

Natural gas supplied by pipeline is able to fill both base and peak load supply niches. While constant product flow is preferred, production is to some extent flexible both seasonally and based on peak demand during shorter periods.

Due to cost factors and infrastructure requirements, LNG has filled a base supply niche; i.e., LNG product flow requirements (e.g., shipping, forward time planning requirements, capital infrastructure) have mandated that it be sold in consistent quantities for constant end user demand. This has precluded it from being the peak load energy source. The market ramification of this requirement is that LNG does not necessarily achieve the marginal market price[10], but is generally bought and sold under long term (multi-year including decadal) contracts. However, as world LNG markets evolve, it could become the marginal supply. In the 1980s LNG contracts were long-term contracts with specified destinations and no short-term sales. Since the mid1990s this has changed as LNG suppliers offered more favorable terms, with the possibility of short-term sales. By 2002

[8] American Gas Foundation, February 2005. Natural Gas Outlook to 2020.

[9] Energy Information Administration, February 2006. Annual Energy Outlook 2005 with Projections to 2030. At: www.eia.doe.gov/oiaf/aeo/index.html

[10] The marginal market price is the price at which the volume demanded equals the amount supplied. If one considers a market where numerous sales and purchases are occurring, and each buyer and seller can negotiate terms, the marginal market price would be the last transaction price that insures all the volumes are bought and sold.

short-term sales represented about 8% of total LNG sales[11]. With LNG consumption forecast to almost triple by 2020[12], it is quite possible LNG could provide "spot" cargoes and thus provide marginal supplies.

Regardless of where ANS gas is delivered, it will be in a volume too large for the local market. If delivered into the Canadian pipeline system in Alberta, or the domestic system near Chicago, it will be transported through existing pipeline systems to additional markets.

VI. Geography and Infrastructure

In a competitive market the price of a good is determined by the forces of supply and demand. At a given price any commodity will enter the market if the cost of bringing it to market is less than the market price. Accordingly, commodities will continue to enter a market until the price falls to a level that is just sufficient for the last source to enter the market at a profit. Thus the lowest cost sources will enter the market first, followed by the next lowest one, etc. The higher cost sources are priced out of the market. The market price represents the cost of the last source to enter the market.

One of the most important determinations of the differences in costs between competing gas reserves is transportation cost. Transportation cost is a direct function of distance to market and geography.

Transporting Alaskan natural gas to a market requires building infrastructure to a market outlet. In the case of the Sponsor Group proposal, the closest significant pipeline infrastructure is in Alberta. But in a decade from now it may not have sufficient capacity to handle all the Alaska gas. Therefore, some increase in pipeline capacity could be required between Alberta and Chicago.

The distance between the North Slope and Chicago is nearly 4,000 miles. Generally, if the gas source is at tidewater, and the destination is tidewater, the most efficient way to transport natural gas over very long distances is with LNG. As gas is cooled and becomes LNG, it is much more compact; the energy density is increased. Unfortunately, liquefying the gas, shipping it, and re-gasifying it are expensive. It is only efficient relative to pipeline transport when distances are very long, and the liquefaction costs per mile are reduced. (The breakeven point depends on relative pipeline, liquefaction, and shipping cost, but is probably around 3,000 miles[13].) In 2005 the longest pipeline in the world was 4,100 kilometers in length (about 2,550 miles) extending from Russia to Western Europe.

[11] US Energy Information Administration, "The Liquefied Natural Gas Market: Status & Outlook", December 2003, pages 38-40.
[12] Petroleum Economist, "Warnings of Limits to Growth", November 2005.
[13] Cornot-Gandolphe, Appert, Dickel, Chabrelie, Rojey, "The Challenges of Further Cost Reductions for New Supply Options (Pipeline, LNG, GTL)", IGU, WGC 2003, Tokyo, Japan, June 4, 2003.

Unfortunately North Slope gas is located 800-miles from tidewater, and there are no large competitive liquid natural gas markets at tidewater on the North American West Coast.

LNG shipments from the Middle-East to the U.S. are less expensive than a pipeline from the North Slope to the Upper Midwest, despite the longer distance. Qatar's gas travels about 8,300 nautical miles from Qatar to New York. The North Slope gas is about 4,000 miles from Chicago. However, Qatar has a lower cost of transportation (per BTU) because its LNG facilities are on the water's edge and transportation only involves tankers. 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 United States. If the pipeline project to Chicago came in on budget, the projected transportation cost would be about $2.20 per million BTU – nearly 80% higher than the Qatar LNG cost estimate.

A pipeline transporting ANS gas could have a distinct cost disadvantage to other gas pipelines. A pipeline through Alaska and portions of Canada will be a more expensive operation than a pipeline through many other types of terrain. This is due to the higher construction and operating costs that the environment places on operation and maintenance.

Thus, North Slope gas could be one of the most expensive resources in the world to bring to market, which would put it near the bottom of the list for competitiveness and incremental introduction into the market. Other gas that is less expensive to transport to market could reduce the market price of gas, leaving a North Slope gas project at risk of losing money.

VII. Price Forecast

As described above, in a competitive market the price represents the cost of the last source to enter the market.

Natural gas has the same essential chemical characteristics regardless of origin and whether it is piped or undergoes re-gasification from LNG. Therefore, natural gas is fungible for end users and facilities do not need to be calibrated to the characteristics of the specific source. This means that the transport method does not affect demand nor does the source of product.

There are many price forecasts, and they have a wide range. The EIA's last published long run forecast[14] calls for increased drilling, new production, and increased LNG imports such that prices initially decline, and increase after 2011. They forecast LNG imports increasing from 1.4 tcf in 2004 to 4.4 tcf/yr in the reference case in 2030.

The EIA presents three scenarios with equal emphasis: reference case, rapid technology, and slow technology. Technological progress affects natural gas production by reducing

[14] Energy Information Administration, February 2006. Ob cit.

production costs and expanding the economically recoverable resource base. In the rapid technology case they state:

> The rapid technology case assumes 50% faster technology progress than in the reference case, resulting in lower development costs, higher production levels, lower wellhead prices per thousand cubic feet, increased consumption of natural gas, and lower LNG imports than in the reference case. In the rapid technology case, lower wellhead prices for natural gas lead to increased consumption and lower import levels.

Their forecast, in constant 2004 dollars is:

Scenario / Year	2010	2020	2030
Rapid Technology	$4.81	$4.22	$5.35
Reference Case	$5.03	$4.90	$5.92
Slow Technology	$5.24	$5.30	$6.36

It is **not** reasonable to believe that today's high natural gas prices will continue over a 40 year period. It is equally not reasonable to believe we can forecast prices over that period. One should keep in mind that natural gas prices were regulated at a relatively low price level for close to 60 years in the last century which encouraged certain industries and facilitated the construction of a great deal of infrastructure. This infrastructure included pipelines to transport the natural gas and production facilities to produce goods from the natural gas, or furnaces to use the gas to heat residential and commercial facilities. History teaches us that unexpected events (including deregulation) will occur which may have a major bearing on price and cost. We just do not know *which* events. The U.S. has recently witnessed the relatively short term effects of a natural disaster on natural gas prices. With infrastructure in place and consumption patterns set during a period of regulation, it is not surprising that (after deregulation) there is limited demand response with a concurrent spike in prices associated with the disaster. This means that consumption of natural gas did not change that much in the short-run, while supplies were reduced significantly by the hurricane. Since the price of natural gas is the balancing factor that changes as consumption and supply change, the price increased dramatically because consumption was relatively fixed while supplies were decreasing.

Longer term effects associated with the high natural gas prices could occur due, for instance, to the perfection of nuclear fusion, driving the cost of producing a BTU of energy to a fraction of what it is today. Even without technology advancement, the substitution or a relatively abundant and low cost fuel, such as coal, may occur. In fact, the most recent long run outlook by the US Department of Energy[15] projects electricity generation from coal fired power plants will grow faster than electricity generation from

[15] US Department of Energy, Energy Information Administration, Annual Energy Outlook 2006 With Projections to 2030", February 2006.

gas fired power plants [2.5% versus 1.7%]. The effect will be that the share of electricity generated from natural gas will decrease from 18% in 2004 to 15% in 2030.

While the discussion has focused on long-term effects, some of the short term responses to the high prices have started to occur as consumers reduce their use of natural gas. There has been substitution of oil for gas in electricity generation, while there has been a warmer than normal winter. The combination has been lower than expected gas consumption which has led to a 59% drop in natural gas prices to $6.31 per million BTUs at the Henry Hub spot market on March 9, 2006 [from $15.39 per million BTUs at the Henry Hub spot market on December 13, 2005].

However, it is also *not* difficult to imagine that the development of 6,000-7,000 tcf of proven natural gas reserves worldwide could exert downward pressure on price. Cambridge Energy Research Associates (CERA) estimates that vast reserves of LNG could be landed in the U.S. at a price varying between $2.75 and $4.00 per mmBTU. If LNG became the marginal supply of gas, this would become the market price. It is the price at which any gas from Alaska would have to compete on a delivered basis.

VIII. Scale of Project

Pipelines are a textbook example of economies of scale. The best way to reduce the unit cost of transporting product through a pipeline is to increase the size of the line. Given the ANS natural gas reserve base, analysts estimate that the efficiency of North Slope economics is maximized by scaling up to the 4 bcf/d size pipeline. Although the per-unit costs are lowered, increasing the size adds to the total capital cost. This has resulted in a very large costly project, estimated at $21 billion.[16]

The $21 billion is the estimated cost to construct a pipeline to Chicago, however, there is the option to construct a pipeline to Gordondale, Alberta and purchase Firm Transportation [FT] commitments on other pipelines to Chicago, Illinois. Should the project sponsors elect to purchase FT commitments to Chicago, there would be another large capital cost[17] – the rather large cost for FT commitments for shipping 4 bcf/d. As an intermediate option, the project sponsors may choose to purchase some FT commitments for some of the gas, and construct a smaller pipeline on to Chicago. In any scenario, the gas has to be moved to Chicago. The total cost is likely to be $21 billion whether the option selected is [1] a large pipeline all the way to Chicago; [2] a large pipeline to Gordondale and FT commitments from Gordondale on to Chicago; or [3] a

[16] The capital costs for an LNG project are not dissimilar. In addition, the LNG project would carry the shipping burden. If the LNG were delivered to a U.S. destination, this would require the use of Jones Act LNG tankers, which would be expected to cost more than that of foreign tankers, exacerbating the non-competitiveness of the Alaska gas.

[17] Purchasing firm transportation commitments is an expenditure that is capitalized.

large pipeline to Gordondale, a smaller pipeline on to Chicago in conjunction with FT commitments from Gordondale to Chicago[18].

Very large construction projects create their own additional risk. 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%) on large projects is extensive.[19]

Issues that can become particularly troublesome for large projects include:

- Contingency set asides
- Permitting delays
- Design changes
- Currency fluctuations
- Interest rate increases
- Changes in technology
- Material shortages
- Project labor agreements
- Material cost increases
- Construction safety concerns
- Unanticipated environmental issues

In the case of the Sponsor Group project, the future cost of steel presents an additional significant risk factor. Since the cost was estimated in 2001, steel prices have doubled.

Also, there is often a lack of personnel and skills to undertake the large projects. In addition, the projects are so complex they either distract management from other projects, or management cannot sufficiently focus on the project.

At $21 billion, the risk of losing money could be financially catastrophic to a small firm participating in the project. For the three large oil companies [BP, ConocoPhillips and ExxonMobil], their potential losses – should the project fail – would be about $15 billion and represent about 30% of their combined profit for 2004.

Small projects may carry a “nimbleness” premium despite their reduced efficiency.[20]

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[18] Firm transportation commitments from Alberta to other markets in Canada and the lower 48 states could be purchased, but Chicago is presented to allow a comparison with the proposed project.

[19] See, for example, Flyvberg, Bent, Bruzelius, Nils, and Rothengatter, Werner, Megaprojects and Risk: An Anatomy of Ambition, Cambridge University Press, Cambridge, United Kingdom, 2003.

[20] Operating costs can be viewed in general terms of cost per BTU delivered. Either a pipeline or LNG project in Alaska has the capacity to deliver about 1/3 of the BTU's per day that the TAPS does at full capacity. Even with the TAPS averaging half capacity the gas system would deliver less BTU’s per day. However, the complexity of the gas transportation system, either a pipeline system roughly four times the length of TAPS or its same length combined with LNG plants, tanker transportation systems, and subsequent pipelines, will be more expensive to operate than the TAPS line overall and much more so on a BTU basis. This results in higher overall transportation costs for ANS natural gas than for oil.

IX. Competition Among Projects Worldwide

Regardless of price, any ANS gas project has to compete against other projects throughout the world for construction materials, priority and financing. Corporations have finite budgets. Only the best projects get funded subject to portfolio management constraints. The major factors of consideration include plans for product development and extraction over time, market constraints, competition, and long term profitability.

PFC Energy conducted a study for the State of Alaska examining the gas pipeline project in the context of the global portfolios that the three Sponsor Group companies have the opportunity to develop.[21] Taken together, the Sponsor Group companies have about 300 new projects and additional mature assets on their development planning horizon. The study was conducted in 2004 and assumed a $22 per barrel oil price.

The study viewed the Alaskan pipeline project from the viewpoint of the individual companies based on their assets and individual investment matrices. The concept of net present value per investment dollar and return on capital employed form the floor upon which investments must be compared. The lower the rating, the lower a project's ranking and the longer delay each company is willing to give it. Two different project lengths, pipelines ending in Gordondale, Alberta or Chicago, Illinois were considered. Based on the net present value per barrel of oil equivalent (a BTU comparison) and per dollar investment, the gas pipeline ranked as follows:

	Chicago	Gordondale
- ExxonMobil	74 out of 100	63 out of 100
- BP	61 out of 77	56 out of 77
- ConocoPhillips	49 out of 61	41 out of 61

These poor rankings reflect Alaskan/Canadian geography and construction challenges, the magnitude of capital construction costs, and subsequent operating cost disadvantage, and the State's regressive fiscal regime. It is reasonable to assume that even if other companies owned the North Slope leases the comparative outcomes would be similar.

PFC also analyzed the project with State participation as a 25% co-owner of the pipeline. Since active State participation results in shared financial risk, the priority of the pipeline project increases for each company. In each case, the priority increased, highlighting the fact that State involvement, or at least more conducive fiscal terms, increases project economic feasibility in the near term [see table below]. However, even with State participation, the Alaska projects are still ranked in the lower half of all but one project.

[21] PFC Energy, "North Slope Gas Projects in the Context of Global Portfolios," October 2004.

	Chicago	Gordondale
- ExxonMobil	62 out of 100	49 out of 100
- BP	55 out of 77	44 out of 77
- ConocoPhillips	40 out of 61	32 out of 61

X. Rate of Return

North Slope gas is far from market. Because of distance and geography, North Slope gas could be one of the most expensive resources in the world to bring to market. This would put it near the bottom of the list for competitiveness and incremental introduction into the market. Any other cheaper gas could reduce the market price, leaving North Slope gas producers at risk of losing money.

Over the last several decades, producers have been hurt by using high price forecasts. Accordingly, they "stress test" their projects by evaluating them at lower prices. We believe today that this "stress price" is about $3.50 per mcf in Chicago.

It is believed that very little Alaska gas will be sold in Alberta; it will be sold either in the Eastern United States, the Upper Midwest, or the Pacific Northwest. The producers will not spend over $14 billion to build a pipeline only to Alberta not knowing how they are going to get the gas beyond Alberta. Moreover, the producers, at *this* point in time, cannot assume there will be available capacity, given the uncertainty regarding additional Western Canada production that could come on line over the next decade.

Even if there is available pipeline capacity to take the gas beyond Alberta, they will need to obtain firm transportation capacity on it. This commitment is capitalized in the economic evaluations.

There will probably be some combination of available and new capacity that will be necessary to move the gas beyond Alberta. However, used capacity does not cost much less than new; old sections are often replaced and maintenance costs are considerable. Therefore, we have examined the economics based on a new pipeline from Alberta to Chicago.

The Department of Revenue estimates the rate of return on the capital investment for the Sponsor Group project to be 14.1% when natural gas prices are at $3.50 per mmBTU. This is lower than what most alternative developing projects will earn. With a 25% capital cost overrun the rate of return is reduced to 12.5%. With a 50% capital cost overrun, the rate of return falls 11.3%.

XI. Fiscal Stability

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 materially alter the project viability.

One of the goals of the Stranded Gas Act is to stabilize State fiscal terms in order to encourage marketing and new development of stranded gas. If the gas were marketed, it would provide additional royalty and revenue to the State of Alaska. If the gas is not marketed, there is no additional revenue to the State of Alaska.

Rates of return and overall project success are built on many factors including return of invested funds and timing. Major investments are much safer when the return on investment occurs earlier in a project. In accounting terms, this means that some types of deferred costs count against profitability less than those incurred earlier in the project. Stated differently, the ability to defer some costs allows recovery of other costs earlier and therefore can increase the fiscal viability of a project.

If the producers spend $21 billion to build the pipeline, the State, at any time, can remove the value from the project by changing the fiscal terms. The producers can take the risk to build the pipeline based on certain tax and royalty assumptions and the State can, by an act of the Legislature, increase taxes to such an extent that risk of the project remains with the producers but the value of the project is transferred to the State. The State could take enough from the producers in taxes that the risk of losing money on the project substantially increases.

XII. Alaska LNG

Most of this analysis has focused on the Sponsor Group Alaska Canada pipeline proposal (ALCAN). The AGPA proposed project is very different from the Sponsor Group project: a pipeline about 800 miles to a port in south-central Alaska with associated LNG compression and tanker facilities. From these facilities the LNG would be transported by tanker to ports on the West Coast. This project would also require the construction of LNG re-gasification plants at receiving ports on the West Coast and pipelines to connect with existing distribution systems to move some of the gas to more easterly markets.

The LNG option is determined to be less viable than the pipeline proposal – which means this project may not “un-strand” the gas on the North Slope. The reasons are threefold:

- First, it appears very likely that the proposed LNG costs would be higher than the pipeline costs.
- Second, it appears very likely that the prices received at the sales point would be lower for the LNG option.
- Third, it appears very unlikely that any of the proposed receiving terminals will be built.

The latest proposal from the Alaska Gasline Port Authority[22] calls for 1 bcf/d delivered to each of Kitimat, B.C., Bradwood, Oregon, and Pendleton and Ventura, California.
Much of this discussion is based on an analysis by PFC Energy[23].

[22] “All Alaska Gasline/LNG Project Agreement” submitted by the Alaska Gasline Port Authority on August 22, 2005.

A. Costs

The Port Authority proposal includes the capital costs within Alaska of getting North Slope natural gas to tidewater, i.e., the conditioning plant, pipeline, liquefaction and LPG extraction facilities, and port facilities. However, there will be considerable additional expenses to transport the LNG to market: a) shipping, b) re-gasification, and c) new inland pipelines. Estimates by PFC reveal that, in total, it would cost an extra $1.03 per million BTU to transport natural gas to the West Coast via LNG including re-gasification, relative to the ALCAN project.

There are multiple reasons for this cost difference. Some of the major reasons include differences in transportation modes and associated cost and the necessity of conversion to LNG and re-gasification after shipping.

Under the Jones Act anything shipped from an American destination to another American destination must be carried on a ship built in the United States, on a ship with a U.S. flag, and staffed by a U.S. crew. In the case where Alaska gas may go to Canada or Mexico for re-gasification and marketing back to the U.S., the Jones Act also applies. The only possible exemptions appear to be for national defense. Re-flagging old U.S. built LNG tankers that have been operating overseas under foreign flags is clearly precluded in the Act.

There are no U.S. shipyards that build LNG tankers. The start-up and construction costs would be high, even for shipyards that are experienced in constructing naval vessels or oil tankers. In the oil trade Jones Act tankers cost more than twice as much to build and operate compared to foreign tankers. There are three main reasons for this: first, U.S. labor costs are higher than foreign. Second, there is little or no competition between shipyards in the U.S. to contain costs. Third, the simple lack of experience and “assembly-line” structure causes inefficiencies. Thus in the case of LNG there is every reason to believe the shipping costs for Alaska LNG would be significantly greater than shipping LNG from foreign jurisdictions. PFC estimated Jones Act tankers would cost 54% more than foreign tankers.

B. Price

As already mentioned, the current Port Authority proposal is to land 4 bcf/d of LNG at four distinct West Coast re-gasification plants. None of these plants are in an advanced stage of permitting and none of them appear likely to be constructed at this time.

Moreover, and most important, the economics of the LNG project are dependent on being able to market 4 bcf/d in order to bring the unit costs down to a reasonable level. The problems of marketing 4 bcf/d of North Slope gas as LNG are very serious.

[23] PFC Energy, “Assessment of the Alaska Gasline Port Authority LNG Project,” prepared for the Alaska Department of Revenue, March 17, 2006. The study also examined Long Beach, California as a possible destination.

The West Coast is a rather isolated market. There is insufficient East-West infrastructure in place to move excess supplies out of the market. Most forecasts project about 2 bcf/d of additional supplies may be required in the next 10-15 years[24]. Shell and BP have already committed to supply Sempra a combined 1 bcf/d of Asian and Australian gas, and Sempra recently conducted an open season to procure the balance. Attempting to sell all 4 bcf/d of Alaska gas in the West Coast market would be a challenge as the Alaska gas would be competing with lower cost competitors.

Moreover, this market will grow incrementally, not all at once. Placing the entire 4 bcf/d into the market at once will be particularly difficult. However, because of the large fixed cost of the pipeline it is necessary to market all of the gas rather quickly. Projects that do not have that large fixed cost, and can put smaller amounts of gas into the market over a shorter time, will have an advantage. Placing 4 bcf/d on the West Coast market would drastically suppress prices.

PFC estimates that 4 bcf/d landed on the West Coast would affect the supply balance such that it would command $0.61/mmbtu less than the same volume landed in Chicago. This is attributable to:

- Much of the gas is landed in next exporting regions. The gas must travel considerable distances to market areas or compete with other sources of supply transiting the region to serve local demand.
- As mentioned above, the size of the incremental supply relative to the market weighs on the West Coast price.

PFC's projection is contingent on the timely construction of West-East pipeline infrastructure to move excess supplies from the region. They warn:

> PFC Energy expects that given the lead time required for either Alaskan gas transportation project, companies would incorporate the incremental supplies in their pipeline planning activities, smoothing the transition. If companies do not do so, then the introduction of Alaskan supplies could prove more disruptive than indicated here, and price discounts for the new gas supplies would be greater than projected here.

As for supplying Asian markets with LNG, it appears unlikely that North Slope gas could compete with the plethora of closer tidewater sources that do not have to build an 800-mile pipeline just to reach the coast.

C. <u>Siting Issues</u>

PFC concluded that it is unlikely any of the proposed U.S. or Canadian West Coast LNG receiving terminals will be built. They rated the likelihood of construction of any of the

[24] This includes forecasts from Cambridge Energy and the California Energy Commission.

terminals in the next decade at poor to negligible, based on environmental, community, permitting, financing, and market issues.

D. Netback Comparison

Between the additional cost and the reduced price, PFC estimates the netback value would be $1.64/mmbtu ($1.80/mcf) less for the LNG project relative to the ALCAN project. This would be $10/bbl less on an oil-equivalent basis.

XIII. Conclusion

Stranded gas is gas that is not being marketed due to cost and price conditions. North Slope gas today certainly fits this criterion. This paper summarizes many of the reasons and presents analysis conducted by the Department of Revenue. The commercialization of North Slope gas will be subject to market forces. Markets fluctuate with the lowest cost supplies coming in to the market first. The cost of these supplies set the price. Higher cost supplies are shut out until the lower cost supplies are depleted.

It has been shown that the reason North Slope gas has not been marketed is the distance from market coupled with Alaska's geography, the existence of vast supplies of lower cost gas in other parts of the world, and the problem that other supplies are not subject to the size risk inherent in the North Slope project. These are the cost and price conditions that are at risk of prevailing during the period in which this project will operate. Therefore, the Department of Revenue concludes that Alaska's North Slope natural gas is stranded.

Appendix D

Consultants

Consultants

The following firms assisted in the analysis and preparation of the Fiscal Interest Finding.

Challenger Capital Group

Challenger Capital Group is an institutional–grade investment bank with an unparalleled foundation of veteran investment bankers with over 20 years of transaction experience. Challenger's team possesses multidisciplinary capabilities and draws upon substantial deal experience. With offices in Dallas and Chicago, Challenger has filled the void created by sweeping consolidation in the investment banking sector by assembling an exceptional staff of professionals with a transaction resume that spans more than 365 transactions and represents over $135 billion in aggregate transaction value.

From energy to industrial products to retail, our team is well versed in numerous industry sectors. The breadth and depth of our team's experience distinguishes our firm and serves our clients well.

http://www.challengercapitalgroup.com

Citigroup

Citigroup is an international financial conglomerate with operations in consumer, corporate, and investment banking and insurance. Their Corporate and Investment Banking (CIB) business provides comprehensive, tailored and unique solutions to top corporations, financial institutions and governments worldwide, offering strategic and financial advisory services including acquisitions, mergers, divestitures, financial restructurings, loans, foreign exchange, cash management, and structuring, underwriting and distributing equity, debt, and derivative securities.

Citigroup provides world-class global capabilities for corporate, institutional and retail investors through their dominant equity and debt sales and trading platforms, industry-leading research, top-tier institutional distribution capabilities, and access to the second-largest retail brokerage network in the U.S. They are a global leader in underwriting, structuring, and sales and trading across all asset classes, including equities, corporate bonds, government and agency bonds, asset-backed and mortgage-backed securities, syndicated loans, structured and futures products.

Citigroup has staff in approximately 100 countries advising companies, governments, and institutional investors.

http://www.citigroup.com/citigroup/products/index.htm

Credit Suisse

Credit Suisse Group is a leading global financial services company headquartered in Zurich. As an integrated global bank, the company provides its clients with investment banking, private banking and asset management services worldwide. Founded in 1856, Credit Suisse has a long tradition of meeting the complex financial needs of a wide range of clients. Credit Suisse offers advisory services, comprehensive solutions and innovative products to companies, institutional clients and high-net-worth private clients globally.

In Investment Banking, Credit Suisse offers securities products and financial advisory services to corporations, governments and institutional investors. Operating in 69 locations in 33 countries, this business specializes in creating innovative solutions to clients' challenges, drawing on expertise from across the full spectrum of products: debt and equity underwriting, sales and trading, mergers and acquisitions, investment research, correspondent and prime brokerage services.

Within the Investment Banking division of Credit Suisse, the Global Project Finance Group is a leading advisor to projects worldwide. The Group includes dedicated professionals in New York and London with extensive track record of leading the largest, most complex and most innovative project financings. Credit Suisse Project Finance professionals have been involved in rating 98 project issues, more than any other firm on Wall Street. The Project Finance Group is part of the Global Energy Group, the largest energy group on Wall Street.

http://www.credit-suisse.com/

Goldman Sachs

Goldman Sachs is a leading global investment banking, securities and investment management firm that provides a wide range of services worldwide to corporations, financial institutions, governments and high net-worth individuals.

Founded in 1869, it is one of the oldest and largest investment banking firms. The firm is headquartered in New York and maintains offices in London, Frankfurt, Tokyo, Hong Kong and other major financial centers around the world.

Goldman Sachs Global Investment Research provides analysis of company and sector performance and market-changing events. They provide in-depth analyses of markets, companies, industries and currencies worldwide and provide fundamental research and investment opinions.

For over two decades, they have dedicated resources on a global scale to develop industry-leading investment research in the areas of economics, portfolio strategy, and equity securities analysis. The Global Investment Research Division covers approximately 1,800 securities, more than 50 economies and over 25 stock markets.

www.gs.com

Government Finance Associates, Inc.

Government Finance Associates, Inc. ("GFA") is an independent public finance advisory firm that assists large state and local governments, public authorities and non-profit institutions in the areas of debt management and capital financing. The firm was established in 1979 and has been a nationally recognized public finance advisor over the intervening period. As an independent public finance advisory firm, GFA does not underwrite, bid on, negotiate for the purchase of or otherwise trade in any securities or loans. Further, GFA is not, in part or in whole, owned by an organization that underwrites, trades or otherwise purchases or invests in securities or loans.

GFA, which supplies financial advice only to significant, complex state and local governments and non-profit institutions, is recognized as one of the more experienced and well-established independent financial advisory firms in the country. As a result, this firm brings a wide range of experience from a multitude of long-term engagements. In fact, GFA has been involved in virtually every type of financing employed in the public finance sector. The firm has clients from Alaska to Virginia.

GFA has been financial advisor to the State of Alaska since 1983. Among the other significant, general purpose governments for which GFA is the financial advisor are the State of Vermont; State of Louisiana; Buffalo, New York; Virginia Beach, Virginia (largest city in Virginia); Onondaga County, New York; Wayne County, Michigan, among many others. GFA is also heavily involved with tax-exempt borrowers represented by authorities and nonprofit entities; among other clients, the firm is also financial advisor for debt management and capital planning to the American National Red Cross, Massachusetts Port Authority (Massport-Logan Airport), Wayne County Airport Authority - Detroit METRO Airport, Cincinnati/Northern Kentucky International Airport, Princeton University, Vermont Economic Development Authority, water and sewer authorities, student loan agencies and other public entities.

Information Insights

Information Insights is a public policy and economic consulting and facilitation firm, offering a broad range of consulting services, specializing in system change; research, analysis and planning studies; strategic planning and public process facilitation; communications and marketing; and program administration and evaluation

Information Insights has expertise in Alaska public policy, public health, housing, education, economics, public finance, facilitation and organizational development to design a project or process to reach each client's unique objectives.

http://www.infoinsights.com/

Latham & Watkins LLP

Since Latham & Watkins was founded in 1934, clients seeking innovative solutions to their most complex business issues have turned to us for our strategic thinking and senior-level attention. Clients depend on us for our ability to get deals done and high-stakes litigation successfully resolved. As business has grown more global, Latham has grown globally as well, so that we can better serve our clients on all of their cross-border needs. In recent years, the firm has expanded to more than 1,800 lawyers, becoming one of the few law firms capable of providing top quality representation worldwide.

Lawyers' roles have evolved from mere legal technicians to valued business advisors – a concept Latham has long understood and embraced. We are recognized for our hardworking culture and the high degree of responsiveness and consistent attention we bring to each client matter. Latham's experienced guidance in a range of matters around the globe – combined with our breadth and depth of resources – offers clients a level of legal representation that most firms simply cannot match.

Latham has a highly regarded transactional practice, and most recently garnered the most top-10 rankings among all law firms in the 2006 The American Lawyer Corporate Scorecard, in categories including mergers and acquisitions and private equity, equity offerings, high-yield and investment-grade debt, initial public offerings, REITs, mortgage-backed securities and project finance.

http://www.lw.com

Lukens Energy Group

Lukens Energy Group (LEG) is a management consulting company advising top management in the energy industry on issues of strategy, markets, regulation, valuation and risk management. They deliver consulting services to state governments, energy cooperatives, municipal utilities, and federal energy agencies.

Their clients within State government include Departments of Revenue and Departments of Natural Resources. They advise State government on issues related to gas market pricing dynamics, pipeline rates and tariffs, and royalties on gas production.

LEG has extensive experience in cost of service, rate design, and regulatory issues faced by public gas and power utilities. They have prepared market studies and price forecasts for a number of public clients. These studies have been used for planning, hedging, and in educating constituents on market trends. They have also been used by financial institutions assessing risk associated with bond financing of energy projects.

LEG has worked with clients in the following utility and related industries: electric utilities, gas utilities, electric and gas distributors, energy services companies, energy retailers, alternate energy companies, distributed generation companies, new energy technology companies, and end users of energy. Examples of services they provide to energy merchants include: asset portfolio analysis, optimization and risk management analysis and tools; marketing and trading strategy assessment and development; valuation of complex transactions and derivatives; and asset valuation and optimization: merchant generation, storage, transportation, transmission and processing.

http://www.lukensgroup.com/

Merrill Lynch Global Markets & Investment Banking Group

Merrill Lynch Global Markets & Investment Banking Group (GMI) is one of the world's top global investment banks, providing institutional sales and trading, investment banking advice and capital raising services to corporations, governments and institutions worldwide.

The Global Investment Banking Group delivers strategic capital-raising and merger and acquisition advisory services with specialized sector expertise. Their debt and equity origination teams help clients raise funds and diversify capital sources by accessing the domestic, international and private markets.

Corporate finance teams provide superior hedging and structured product solutions tailored to clients looking to maximize returns and minimize risk.

Their global leveraged finance team specializes in high-yield capital markets, loan syndication and leveraged finance origination.

http://www.ml.com/?id=7695_8134_8299_6707&hps=ob

Morrison & Foerster, LLP

With more than a thousand lawyers in nineteen offices around the world, Morrison & Foerster offers comprehensive, global legal services in business and litigation.

Morrison & Foerster represents a broad range of interests in the energy and natural resources sector. The firm represents gas and energy traders and marketers, energy service providers, investor-owned and municipal utilities, pipeline companies, forestry companies and minerals and mining concerns. The firm also represents industrial and commercial customers, investors, financial institutions, public entities and other clients who do business with energy and natural resources concerns.

Morrison & Foerster has handled major regulatory, litigation, environmental, land use, bankruptcy, tax, securities, antitrust, and transactional matters for both U.S. and international energy and natural resources clients. In addition, Morrison & Foerster provides assistance to governmental agencies and other clients on numerous regulatory and transactional matters, including the deregulation of and new regulatory framework for natural gas markets.

Morrison & Foerster also offers clients expertise across all major infrastructure categories, including oil and gas, pipelines, power and LNG, transportation and telecom, and in numerous countries around the world. The firm represent lenders, developers, export credit agencies and multilateral organizations, governments and contractors in all aspects of major infrastructure projects. The firm also advises developers and financial investors in connection with the sale and acquisition of infrastructure assets.

http://www.mofo.com/

Muse Stancil

Muse Stancil is a global consulting firm specializing in the energy industry, providing practical solutions across a range of industry issues.

Founded in 1984, Muse Stancil offers a unique blend of hands-on experience, industry insight, and consulting skill. Muse consultants bring an average of 16 years of direct industry experience from operating companies and 26 years of total experience in the global energy industry. Clients range from multinational energy firms and independent petroleum marketers to banks and law firms involved in the industry. Their staff is primarily degreed chemical engineers, many with advanced technical and business degrees.

One of their core strengths is developing strategies that help energy companies deal with rapidly changing political and economic conditions around the world. Their expertise includes assessing the economics of a business structure and evaluating the competitive landscape through knowledge of specific markets such as refining, gas processing, lubricants, chemicals, and cogeneration.

That expertise has stretched throughout the world, from North America, Latin America and Asia to Central and Eastern Europe where they are known for their ability to position multinational companies for growth and profitability.

Their clients include financial institutions, oil companies, law firms, pipelines and utilities, governments and state agencies.

http://www.musestancil.com/home.html

Northern Economics

Northern Economics is the largest professional economics consulting firm in Alaska. Our offices are located in Anchorage, Alaska and Bellingham, Washington. Northern Economics, founded in 1982 and incorporated in 1998, has developed a long-term, in-depth understanding of the oil and gas industries in Alaska. As the petroleum industry has emerged as a major segment of the Alaskan economy, Northern Economics has grown along with it, helping state and local governments and private businesses in Alaska develop an economy for present and future generations. Northern Economics provides feasibility analyses, environmental impact statements and assessments, benefit-cost analyses and other services to facilitate pubic sector and private sector growth and decision-making. NEI projects include economic impacts and benefit assessments of oil and natural gas development; as well as economic and socioeconomic evaluations for development of oil and gas reserves, construction and operation of gas handling facilities, replacement of TAPS line segments, and Outer Continental Shelf oil exploration. In addition, Northern Economics conducted the economic and/or socioeconomic analyses for most of the proposed gas pipeline projects that have come forward in the past several years.

In addition to the firm's work on the economic and socioeconomic impacts of pipelines and other oil and gas industry projects, NEI has developed expertise in a number of regulatory processes and has contributed to environmental impact statements for a number of different private companies, state, and federal agencies, environmental assessments for these same groups, best interest findings for the Alaska Department of Natural Resources, and specific regulatory requirements related to the effects of regulatory changes on small businesses. Over the 100-plus years of experience in preparing regulatory and environmental analyses, the staff at Northern Economics has developed a keen understanding of strategies and techniques that can be used to accommodate projects that are not well defined, and ways to present complicated financial and economic issues in terms that can be understood by the public.

http://www.northerneconomics.com/

Osler

Osler, Hoskin and Harcourt LLP ("Osler") is a leading Canadian law firm with over 425 lawyers. Osler has extensive expertise in the structuring and development of complex energy and infrastructure projects and its lawyers have been involved in most of the significant pipelines between Canada and the United States. Osler is also a leader in many areas of Canadian law including regulatory, environmental, business, tax, mergers and acquisitions, financing and competition law.

http://www.osler.com

Paragon Engineering Services

AMEC Paragon is one of the leading project management, engineering services and asset management organizations in Houston. The company was created by the merger of two industry-recognized leaders, AMEC and Paragon Engineering Services.

AMEC Paragon manages all aspects of oil and gas, pipeline, and midstream projects. AMEC Paragon is frequently called upon to manage entire development efforts on the owner/operator's behalf. Keys to AMEC Paragon's success in project management include proprietary tools and procedures for estimating and controls as well as the ability to follow through with comprehensive procurement and construction management services.

AMEC Paragon's upstream capabilities encompass onshore and offshore facilities and structures for all types of environments and applications with expertise in process/facilities, civil/structural, instrument/controls, and electrical engineering and design along with procurement, inspection, and construction management services for facilities ranging from onshore pump and compressor stations to shallow- and deepwater platforms, floating installations, and sub sea systems.

AMEC Paragon's full service pipeline group specializes in pipeline design, mapping, pipeline integrity management system development and implementation, corrosion detection and control, modeling and flow assurance services, and compression/metering facility design for onshore and offshore gas and liquids pipelines. They employ a combination of proprietary and commercial mapping and GIS systems to automate the development of data and deliverables in order to minimize costs and enhance global coordination of all types of pipeline efforts.

AMEC Paragon's civil/structural, electrical, instrument/controls, process/facilities, environmental, and Human Factors Engineering groups collaborate in integrated teams to provide a full package of engineering and design services for onshore projects. In addition, AMEC Paragon's procurement, inspection, and construction management groups provide valuable consulting on the front-end as well as the resources required to guide onshore projects through to commissioning, start-up, and operation.

http://www.paraengr.com/

PFC Energy

PFC Energy was established in 1984 and is one of the pre-eminent strategic advisory firms in global energy. Combining a detailed knowledge and understanding of markets, countries and competition, PFC Energy is recognized in the global energy industry for the depth of its analysis and the integrity of its advice.

PFC Energy is a respected and valued advisor to energy companies and governments across the globe advising on business development opportunities, upstream and downstream strategies, international gas and LNG strategies, power strategies, oil market and petroleum sector risk, and effective investor relations programs.

The company uses its upstream expertise to evaluate regional and global supply perspectives and its refining and marketing expertise to evaluate the outlook for regional and global petroleum product demand. PFC Energy also provides detailed coverage for gas and power markets. PFC Energy utilizes a unique methodology that combines modeling of gas and power supply/demand fundamentals with its models and analysis of gas and power infrastructure development to provide both short-term and long-term gas market forecasts.

PFC Energy is recognized as an industry leader for its understanding of the dynamics of National Oil Companies (NOCs). The strategies of the NOCs are varied and changing, depending in large part upon the role that they perform within the national political economy. Whether privatizing or not, most NOCs are now focused on achieving commercial performance. PFC Energy provides an understanding and analysis of the strategies and trends which can be critical to relationships with host governments, international oil companies and the availability of investment opportunities.

http://www.pfcenergy.com/

Preston Gates

Founded in 1883, Preston Gates has a long history of providing private and public sector clients with sound legal counsel and trusted representation. The firm's more than 400 attorneys practice across broad areas of the law, handling complex business transactions, litigation and intellectual property matters, as well as governmental, regulatory and public policy work. The firm operates from 11 strategic locations on the West Coast, in Washington, DC and in Asia.

The energy and utilities practice group leverages experience from a wide variety of legal disciplines to handle and resolve the broad spectrum of issues facing the industry and maintains a thorough grounding in both the legal and business dimensions of the energy and utilities industry.

Highlights of the experience of attorneys in the group include: heading the Bonneville Power Administration (BPA) transmission business; serving for 14 years as BPA's general counsel; serving 18 years in the U.S. Senate; working as Northwest regional director of the National Marine Fisheries Service; helping develop energy projects in India and Pakistan; and serving as chief of the Energy Section of the U.S. Department of Justice's Antitrust Division and as the department's principal counsel before the Federal Energy Regulatory Commission (FERC).

http://www.prestongates.com/

Price Waterhouse Coopers, LLP

Price Waterhouse and Coopers & Lybrand (PwC) is an international accounting and consulting firm and a global market leader for tax services. They assist businesses, individuals and organizations with tax strategy, planning, and compliance, and deliver a wide range of business advisory services with 23,000 dedicated tax professionals in over 140 countries.

They combine industry insight with the technical skills of financial and tax professionals, economists, lawyers and our other in-house resources as necessary, to develop comprehensive integrated solutions. They work with an expansive and diverse client-base comprising all types of businesses — multinationals, local companies, privately-owned organizations, entrepreneurs, family businesses, trusts, partnerships and private individuals.

The network of PwC international tax structuring professionals is experienced in addressing all aspects of international taxation. They can assist in structuring businesses in a tax-efficient manner, locally and globally; constructing effective cross-border strategies; managing global structural tax rates; and informing on new developments in the international arena. They also advise on: tax efficient holding company locations; cross-border financing and treasury solutions; controlled foreign companies tax planning; income tax treaties, profit repatriation, loss utilization; inbound and outbound structuring; managing intellectual property and intangible assets; tax efficient supply chain and shared services; and regional tax issues e.g. EU tax harmonization.

www.pwcglobal.com/

UBS Financial Services

UBS is a full-service, global, financial firm with strong domestic and local ties that offers an ideal platform from which to assess alternative business models and to design and successfully execute the Natural Gas Pipeline Project.

Over the past 10 years, UBS has advised on over $80 billion in electric and gas projects with a global utility and energy advisory team, including 42 bankers in the U.S. and 9 in Canada. UBS is the leader in worldwide mergers and acquisitions, integrated debt and equity financing, and secondary equities with an extensive institutional and retail investor networks, a strong underlying credit ratings, and in-house tax and credit analysts. UBS is the industry leader in energy trading and marketing and operates wholesale natural gas and power markets in the U.S. and Canada with 110 energy professionals based in the U.S. and Canada.

http://financialservicesinc.ubs.com/Home

Wood Mackenzie

Wood Mackenzie has been a respected adviser to the energy industry for more than 30 years providing energy companies and financial institutions with analysis which is commercial, forward looking and value based.

Wood Mackenzie's research and consulting businesses are highly integrated and provide a full range of services to the world's leading energy companies ranging from content and analytics through to action orientated advice.

Wood Mackenzie has more than 190 dedicated energy professionals including a range of recognized industry leaders.

Wood Mackenzie applies its integrated research and consulting services to the upstream oil & gas, LNG, gas & power, and downstream oil sectors. Their clients include all of the major energy companies and leading financial services organizations.

http://www.woodmacresearch.com/cgi-bin/corp/portal/corp/corpPortal.jsp

Ziff Energy Group

Ziff Energy Group, founded in 1982, is a leading international energy consulting firm providing sophisticated industry and operational business analysis, specialized consulting, and learning services to the global energy industry. With offices in Houston and Calgary, the two principal oil and gas centers in North America, their staff of 55+ includes senior industry specialists, each with 15 - 25+ years of domestic and international experience.

Ziff Energy Group's specialists have undertaken numerous consulting assignments for clients that span all aspects of the natural gas value chain. Current clients include natural gas marketers, pipelines, storage operators, gas distribution companies, industrial gas buyers, governments, E&P companies, service providers, and financial institutions.

Ziff Energy Group is a leading global energy solutions firm renowned for its expertise, integrity and uniquely independent position to deliver practical natural gas strategies to all sectors of the industry. Recognized for depth of knowledge in gas markets, supply, pipeline, storage, regulatory matters, and long-term natural gas price outlooks, they provide comprehensive studies that measure upstream performance for more than 100 exploration and production companies throughout the world

http://www.ziffenergy.com/default.asp

Appendix E

Article-by-Article Summary of Alaska Stranded Gas Fiscal Contract

APPENDIX E

ARTICLE-BY-ARTICLE

SUMMARY

OF

ALASKA STRANDED GAS FISCAL CONTRACT

TABLE OF CONTENTS

PARTIES

The following are the Parties to the Contract:

- State of Alaska
- BP Exploration (Alaska) Inc.
- ConocoPhilips Alaska, Inc.
- ExxonMobil Alaska Production Inc.

RECITALS

The Contract contains 14 recitals that offer an insight into the Parties' intent, understanding and objectives with regard to the Contract and the Project, and state as follows:

- The State finds that the Project and the Contract are in the public interest and that without the Contract a valuable resource might not be developed.
- The State finds that the Contract is consistent with the Alaska Constitution and other State law.
- The Participants and the State are committed to the Contract in order to facilitate the construction of a natural gas pipeline from the ANS.
- The Commissioner of Revenue has determined that:

  (i) the SGDA procedural requirements for developing and negotiating the Contract has been met;

  (ii) the Gas is "stranded gas" under the SGDA;

  (iii) the Contract terms meet the requirements and advance the purposes of the SGDA, are in the long term fiscal interests of the State, and balance the principles specified in the SGDA;

  (iv) the Project will substantially benefit the State and the people of Alaska;

  (v) the Contract furthers the stated purpose of the SGDA of encouraging new investment to develop stranded gas;

(vi) the Contract furthers the goal of providing Alaskans who want a job on the Alaska Project to obtain one.

- The State's taking Gas in kind and taking an ownership in the Project will reduce Project risk and improve alignment among the Parties.
- Undeveloped ANS gas resources, including those from the PTU, plus known ANS resources, underpin the Project.
- Each Producer (or affiliate) intends to acquire firm transportation Capacity in an initial Open Season.
- The Parties' share the objectives of providing offtake points within Alaska to accommodate in-state gas consumption, and developing appropriate in-state tariffs.

ARTICLE 1: DEFINITIONS

Some 300 separate definitions used in the Contract are set forth in this first Article. All defined terms are italicized and set forth in initial capital letters wherever they are used in the rest of the Contract. Many are highly technical but must be used to accurately reflect the Contract terms. Listed below are some of the commonly used definitions.

"Alaska Project" means the portion of the *Project* located in *Alaska*.

"Alaska to Alberta Project" means the portion of the *Project* from the Alaska-Canada border to the *Alberta Hub*.

"Alberta to Lower 48 Project" means the portion of the *Project* that involves the export of *Gas* from the *Alberta Hub* to the *Lower 48*.

"Alcan Element" means a *Gas Transmission Pipeline*, a *GTP*, the *Mainline*, or the *Alaska to Alberta Project*.

"ANS" means the Alaska North Slope, which is the portion of *Alaska* north of sixty-eight degrees (68º) North latitude.

"Associated State Gas" means *State Gas* that is associated with *Producer Gas* of an individual *Producer*.

"Capacity" means the:

(a) firm capacity for an *Alcan Element* acquired through any *Open Season* or from an *Alcan Element* as a replacement shipper for a period of more than one (1) *Calendar Month* for those portions regulated by the *FERC* or the appropriate Canadian regulatory agency; or
(b) access rights under a commercial arrangement for those portions not regulated by the *FERC* or the appropriate Canadian regulatory agency**.**

"Capped Tax" means any one of the following *Taxes*:

(a) a sales or use tax on the purchase or use of goods or services;
(b) a gravel severance or mining license tax; or
(c) an excise tax, including a bed or motor fuel tax,
but excluding a *Restricted Tax*.

"Commencement of Commercial Operation" means the end of the *Day* that is the in-service date of the *Mainline* designated in a filing under 18 C.F.R. 157.20(c)(2).

"Confidential Information" means information that is

(a) reviewed by a *Party* in performing an audit under this *Contract*; or
(b) marked "confidential" by a providing *Party* and submitted to a receiving *Party* under the terms or in furtherance of this *Contract*,

but does not include:

(i) *Non-Confidential Information*; or
(ii) *Project Information* except as provided in Article 29.6.

"Contract" means this fiscal contract between the *State* and the *Participants*.

"Delivery Point" means a location where *Gas* is metered for custody transfer either into the first *Midstream Element* or into a pipeline for shipment off a *Property*.

"Derivative Material" means all notes, analyses, compilations, studies, summaries, or other material, however documented, containing or based, in whole or in part, on *Confidential Information*.

"Disposal Property" means a *Property* into which *Impurities* are handled or *Disposed*.

"Effective Rate" means, for a *Producer Capacity Holder* or a *State Capacity Holder*, the

(a) *Rate* for a *Facility* regulated by the *FERC*;
(b) *Rate* for a *Facility* regulated by the appropriate Canadian regulatory agency; or
(c) *Rate* for a private commercial arrangement, if the *Facility* is not regulated by the *FERC* or the appropriate Canadian regulatory agency.

"Excess Property Capacity" means, for a *Producer*, a *Property* and an *Alcan Element*, the amount by which the sum of *State Takeaway Capability* and *Producer Takeaway Capability* exceeds the sum of *Forecast Associated State Gas and the Forecast Producer Gas.*

"FERC" means the Federal Energy Regulatory Commission of the United States Department of Energy.

"Fiscal Obligations" means the following obligations of each *Participant* to the *State*:

(a) *Volumes* due to the *State* from individual *Producers* under Articles 12 and 13; and
(b) monetary payments due and payable to the *State* by individual *Participants* under Articles 11, 12, 13, 14, 15, 16, 17, 18, 19, and 22.

"Fixed Payable Tax" means any one of the following *Taxes*:

(a) a *Vessel Tax*;
(b) property tax on property assessed under AS 29.45, other than AS 29.45.080, that is or could be imposed on a taxable asset to the extent it is not used for the *Project* (Non-Project Real or Personal Property);
(c) property tax on property assessed under AS 29.45.080 and AS 43.56.060(c) that is or could be imposed on a taxable asset to the extent it is not used for the *Project*

and located outside the *ANS* (Non-ANS Exploration Property);

(d) property tax on property assessed under AS 29.45.080 and AS 43.56.060(d) that is or could be imposed on a taxable asset to the extent it is not used for the *Project* and not located or intended to be located ultimately within the *ANS* (Non-ANS Production Property); or

(e) property tax on property assessed under AS 29.45.080 and AS 43.56.060(e) that is or could be imposed on a *Gas* pipeline taxable asset to the extent it is not used for the *Project* (Non-Project Pipeline Property);

but excluding a *Restricted Tax*.

"Fixed Royalty" means the portion of royalty, payable as a fixed royalty share or the minimum royalty in the case of a sliding scale royalty.

"Forecast Ratio" means, for a *Producer, a Property* and an *Alcan Element*, the ratio:

(a) the numerator of which is the *Forecast Associated State Gas*; and

(b) the denominator of which is the *Forecast Associated State Gas* plus the *Forecast Producer Gas*.

"Gas" means a mixture of hydrocarbons and *Impurities* in the gaseous phase.

"Gas Recoupment" has the meaning provided in Article 22.1(d).

"Gas Transmission Pipeline" means a pipeline *Facility* designed to transport *Gas* from *Upstream Facilities* to the *GTP* or *Mainline*.

"GTP" means a *Gas* treatment plant *Facility*, located on the *ANS*, designed to condition and compress *Gas* and remove certain *Impurities* before delivery into the *Mainline*.

"Impurity" means a non-hydrocarbon substance contained in or removed from *Gas*, including carbon dioxide, hydrogen sulfide, helium, mercury, water vapor, and, when removed from *Gas*, trace amounts of hydrocarbons.

"Impurity Disposal Fee" means the fee charged by *Working Interest* owners of a *Disposal Property* to *Dispose* of *Impurities* each time they are *Disposed.*

"Incremental Royalty" means the portion of royalty payable as a sliding scale royalty, supplemental royalty, or net profit share that is in addition to the *Fixed Royalty*.

"Interest" means the amount calculated using the rate and methodology defined in Article 36.2.

"Loss" means any liability, loss, damages (including consequential, incidental, lost profits, special, or punitive damages), demand, claim, settlement payment, cost, expense (including any litigation expense), interest, award, judgment, diminution in value, fine, fee, and penalty, or other charge.

"Mainline" means 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 *Offtake Points* and to connect with the *Non-Alaska Project*.

"Mainline Entity" means the *Project Entity* formed to own the *Mainline*.

"Midstream Element" means a *Gas Transmission Pipeline*, a *GTP*, the *Mainline* or a *NGL Plant* if located in *Alaska*.

"Midstream Entity" means a *Project Entity* formed to own one or more of the *Midstream Elements*.

"NEB" means the National Energy Board of Canada.

"NGLs" means the liquid hydrocarbons recovered or extracted from *Gas* at an *NGL Plant*.

"Non-Alaska Project" means, collectively, the *Alaska to Alberta Project* and the *Alberta to Lower 48 Project*.

"Open Season" means a *FERC* pre-subscription or open season, or a corresponding process on a Canadian regulated pipeline that is conducted in accordance with the rules and regulations in effect, including the offering of a cost-of-service rate, if required.

"Participant" means *BP*, *CP*, or *EM*, *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*.

"Parties" means the *State* and all *Participants*.

"Party" means the *State* or each individual *Participant*.

"Person" means a natural person, trust, estate, government, partnership, joint venture, corporation, association, society, limited liability company, firm, or any other entity having an independent legal existence including the *State* or any *Political Subdivision*.

"Political Subdivision" means a municipality, borough, city or other local government unit of the State of Alaska existing on or after October 1, 2005, and granted the power under the *Alaska* Constitution to impose *Taxes*.

"Producer" means *BP*, *CP*, or *EM* and their respective *Assignees* under Article 31 in their capacity as a *Working Interest* owner of a *Property*.

"Producer Capacity Holder" means an *Affiliate* of a *Producer* that holds or will hold *Capacity* on behalf of that *Producer*.

"Producer Gas" means a *Producer's* share of *Royalty Bearing Gas* and *Tax Bearing Gas*.

"Producer Takeaway Capability" means, for a *Producer*, a *Property* and an *Alcan Element*, the sum of the *Volume* or *Quantity* of *Producer Capacity* and *Producer Upstream Sales Gas*, as identified in the most recently amended *Capacity Notice*.

"Project" means the *Project* described in Article 4, as amended from time to time, and replacements or improvements to the *Project*.

"Project Entity" means a *Person* formed to own one or more of the *Midstream Elements* or a portion of the *Non-Alaska Project*.

"Project Sanction" means the first *Day* on which:

(a) both *FERC* and *NEB* have issued certificates of public convenience and necessity; and

(b) the *Mainline Entity* has given *Notice* to the other *Parties* of its decision to proceed with construction of its portion of the *Project*.

"Property" means an *ANS* lease or *Unit* described in Exhibit D or added to Exhibit D under Article 31.4.

"PTU" means the Point Thomson Unit, which consists of oil and gas leases subject to the Point Thomson Unit Agreement on January 1, 2005, or as later expanded or contracted.

"Restricted Tax" means a Tax:

(a) levied on the items described in AS 43.55.017 or AS 43.56.020, as they read and were applied on October 1, 2005;

(b) described in AS 43.56.030 or AS 29.45.810, as they read and were applied on October 1, 2005; or

(c) that has been replaced by *Impact Payments* or by a payment in lieu of *Tax* under this *Contract*, including on or before *Commencement of Commercial Operations*, a property tax on property assessed under AS 29.45.080 and AS 43.56.060(e) that is or could be imposed on a taxable asset, to the extent the property is used ultimately for the *Project* (Pre-Startup Project Pipeline Property).

"Royalty" or ***"Royalties"*** means an interest in *Gas* production payable, either in kind or value, in favor of the *State* from a *Property*, whether payable as a *Fixed Royalty* or *Incremental Royalty*.

"Royalty Bearing Gas" means the *Quantity* or *Volume of Gas* originating from a *Producer's Property* that is subject to a *Royalty*.

"Royalty Gas" means the *Quantity* or *Volume* of *Royalty Bearing Gas* that the *State* is required to take in kind as its *Fixed Royalty*.

"SCIT" means any tax imposed on or measured by net income including any taxes imposed on or measured by an amount arrived at by deducting expenses from gross income, one or more forms of which expenses are not specifically or directly related to particular transactions, including the taxes imposed under AS 43.19 – 43.20.

"SGDA" means the Stranded Gas Development Act, AS 43.82.010 - .990, as of the date the *Authorization Act* becomes law.

"State" means the *Alaska* government, but excluding its judiciary and any independent or quasi-judicial regulatory agency, such as the Regulatory Commission of Alaska or the Alaska Oil and Gas Conservation Commission.

"State Capacity Holder" means a *State* entity that holds or will hold *Capacity* on behalf of the *State*.

"State Takeaway Capability" means, for a *Producer*, a *Property* and an *Alcan Element*, the sum of the *Volume* or Q*uantity* of *State Capacity* and *State Upstream Sales Gas* as identified in the most recently amended *Capacity Notice*.

"Takeaway Ratio" means, for a *Producer*, a *Property* and an *Alcan Element*, the ratio

(a) the numerator of which is the *State Takeaway Capability*; and
(b) the denominator of which is the *State Takeaway Capability* plus *Producer Takeaway Capability*.

"Targeted Tax" means a *Tax* that would otherwise meet the definition of a *Capped Tax* except that it is enacted or changed after October 1, 2005 and results in or is expected to result in combined total payments by:

(a) the *Participants* and *Affiliates* on their oil and gas related business activity in *Alaska*; and
(b) contractors and subcontractors on their business activity related to the *Project* or *Properties*,

in excess of twenty percent (20%) of the total or expected total amount of the *Tax* in any *Calendar Year*.

"Tax" means:

(a) a tax, levy, impost, fee, license, special assessment, charge, surtax, surcharge;
(b) a franchise, sales, use, excise, value-added, privilege or transfer tax; or
(c) any other government-created mandatory payment that is or could be imposed by the *State* or *Political Subdivisions* under any *Law*, or the people of *Alaska* under AS 15.45 or any other *Law*,

including:

(i) an oil and gas production tax and surcharge under AS 43.55 or any other tax on the development, extraction, or production of natural resources or on reserves or resources in place except for any obligation to pay production tax on behalf of a private royalty owner;

(ii) an oil and gas exploration, production and pipeline transportation property tax under AS 43.56;
(iii) a *SCIT* or any other tax that is based on or measured by gross or net income;
(iv) a municipal sales and use tax under AS 29.45.650 - 29.45.710 or any other sales and use tax;
(v) a municipal property tax under AS 29.45.010 - 29.45.250 or 29.45.550 - 29.45.600 or any other ad valorem or property tax; or
(vi) a municipal special assessment under AS 29.46 or any other special assessment;

but excluding:

(A) civil or criminal fines or penalties generally applicable to *Persons* in *Alaska*; and
(B) reasonable, customary, and non-discriminatory fees generally applicable to *Persons* in *Alaska* to reimburse the *State* or a *Political Subdivision* for its costs of providing specific goods or services to the public or commercial enterprises.

"Tax Bearing Gas" means the *Quantity* or *Volume* of *Gas* originating from a *Producer's Property* that is delivered to a *Delivery Point* after subtracting:

(a) *Royalty Gas*;
(b) the *Quantity* or *Volume* of *Gas* equal to the royalty due on private and federal leases in *Alaska*; and
(c) the *Quantity* or *Volume* of all *Gas* originating from federal leases in the *Outer Continental Shelf*.

"Tax Bearing Gas Payment" has the meaning provided in Article 13.1(a).

"Tax Bearing Gas Percentage" has the meaning provided in Article 13.3.

"Tax Gas" means the *Quantity* or *Volume* of *Tax Bearing Gas* that the *State* receives under Article 13.6.

"Tribunal" means the panel of arbitrators described in Exhibit C.5(a).

"Unit" means a collection of leases subject to an approved *State*, federal, or joint *State* and federal unit agreement in which a *Producer* holds an interest.

"Upstream Facilities" includes 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*.

"Working Interest" means an ownership interest in a *Property* granted by a lease, operating agreement, fee title or otherwise under which the owner of the interest has the right to drill for, develop and produce oil and gas, and the obligation to pay, either in cash or out of production or otherwise, a portion of the expenses.

ARTICLE 2: DRAFTING CONVENTIONS

Article 2 lists eleven (11) drafting conventions that explain how to interpret various words, references, and rights or obligations. For example, the capitalization or italicization of certain words or phrases means that a defined term under Article 1 is being utilized. Another example is the words “and” and “or”. In the Contract the word “and” is used in the joint sense of uniting things: “A and B” means A and B jointly, but not severally. The word “or” is used in the inclusive sense, not the exclusive sense: “A or B” means A or B, or both.

ARTICLE 3: TERM

1. **Effective Date**. The Contract becomes effective when it has been signed by all the Parties to the Contract (“Effective Date”).

2. **Term**. The Term begins on the Effective Date and will remain in effect for 35 years from the Commencement of Commercial Operations, that is, when gas starts flowing on the pipeline. A Force Majeure event (see Article 35) may extend the Term provided that under no circumstances will the Term extend beyond 45 years from the Effective Date. Certain provisions of the Contract that pertain to oil fiscal stability do not apply after December 31, 2035 unless the State and the Participants mutually agree to extend them.

ARTICLE 4: QUALIFIED PROJECT DESCRIPTION

1. **Project Description**. The Project includes a pipeline and related facilities and Capacity to treat and transport approximately 4 billion cubic feet of natural gas per day from the ANS to North American markets.

2. **Project Components**. The Project will consist primarily of:

   - Gas Transmission Pipelines: Pipelines delivering Gas to the GTP or Mainline from the Upstream Facilities.

   - GTP: A gas treatment plant located on the ANS used to remove Impurities from the Gas and compress and chill the Gas.

   - Mainline: The large diameter, high-pressure pipeline, with compressor stations placed along it at regular intervals, routed along the TAPS pipeline and Alaska Canada Highway.

   - NGL Plant: A processing plant to recover NGLs for sale and condition the Gas to market specification. It may either be newly-constructed or an existing facility, and could be located in either Alaska, Canada or the Lower 48.

   - Alaska to Alberta Project: Gas transported from Alaska to Alberta, Canada.

   - Alberta to Lower 48 Project: Gas transported from Alberta, Canada to the Lower 48 (the final portion of the Project). This transport may be accomplished by use of a new pipeline, existing pipeline Capacity, expansion of existing pipeline systems or use of other pipeline concepts.

ARTICLE 5: WORK COMMITMENTS

1. **Performance Standard**. Until the point when both the FERC and the NEB have issued certificates authorizing the Project, and the Mainline Entity has given notice of its intent to proceed (collectively, "Project Sanction"), Participants are required to advance the Project "as diligently as is prudent under the circumstances." This standard is defined under the Contract as "Diligence."

2. **Participant Commitments**. There are three planning-related requirements:

   (i) Project Implementation: Requires that Participants begin Project planning no later than 90 days after the Effective Date; subsequently, Participants must advance planning with Diligence and conclude with a decision whether to begin regulatory applications and Open Season planning.

   (ii) Qualified Project Plan: This is a plan prepared by the Mainline Entity on behalf of the Participants that, beginning April 1, 2006 and until the Commencement of Commercial Operations, will be amended and submitted to the State annually. The plan will outline how the Project will be implemented.

   (iii) Project Summary: The Qualified Project Plan must include a Project Summary with the following information:

      (a) Project overview;

      (b) description of work accomplished

      (c) estimated Project schedule and proposed development activities; and

      (d) description of expenditures and programs implemented under the Alaska workforce training and development programs described in Article 6.4.

3. **Termination**. The Contract provides that the exclusive remedy for the State if the Participants do not exercise Diligence is through termination of the Contract before Project Sanction. The State must establish by "clear and convincing evidence that the Participants have not acted by Diligence, resulting in a "material adverse impact to the Project", and the Tribunal must take into account the following:

   (i) U.S. regulatory processes, construction costs, gas prices and other considerations that may impact planning and development;

   (ii) Canadian regulatory processes and aboriginal issues. If the State seeks to terminate based on these Canadian factors, the Tribunal hearing a dispute must be instructed that other major pipeline projects have experienced delays in Canada;

(iii) errors in judgment may not be used to support termination;

(iv) failure of a Party to enter into a commercial agreements or settle a dispute with another Person may not be used to support termination;

(v) a Participant's suspension of its obligations under Articles 5, 27, 28, or 35 may not be used to support termination; and

(vi) a presumption exists that the Contract continues.

4. **Termination Process**. The State may initiate the termination of the Contract by providing a termination notice to all Participants, which may be disputed by one or more Participants, and the Participants my suspend their obligations in response and are additionally provided with the opportunity to cure. The following is the termination process in greater detail:

A. Notice of Dispute.

(i) Undisputed Notice: If all Participants consent to the termination notice, the Contract expires on the 60^{th} day after issuance of the notice.

(ii) Disputed 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 Article 26 (Mandatory Dispute Resolution), except the Parties are not required (a) to exhaust the amicable resolution process, (b) the Tribunal only decides the issue of Diligence under the clear and convincing evidence standard, and (c) the decision may be made public.

B. Suspension by Participants. Once the State issues a termination notice, the Mainline Entity may suspend its obligations, and, subsequently, any Participant may suspend by providing a suspension notice to the State and all other Participants. Suspension may not, however, be invoked until the end of any cure period.

(i) The suspension notice remains in effect until terminated by the Mainline Entity or the date of a final, non-appealable resolution of the dispute.

(ii) While the Mainline Entity suspension notice is in effect, each Mainline Entity or impacted Participant obligation identified in the suspension notice is suspended, except for payments due under Articles 14, 15, 17 and 19.

(iii) Each Party bears its own costs incurred in connection with a suspension, and no penalty or Interest accrues on amounts otherwise payable by the Mainline Entity or impacted Participants to the State.

(iv) After the end of suspension, if the Contract remains in effect, the time periods for obligations are extended equal to the length of the suspension.

If the Contract terminates, the Mainline Entity and the impacted Participants are free of further obligations except for rights, privileges or obligations that accrued before the earlier of the effective date of the Mainline Entity suspension notice (if there was one) or the date of the final non-appealable resolution of the dispute.

C. Opportunity to Cure. Once the State issues a termination notice, the Participants have 90 days from the date of the notice to take any actions they deem appropriate to address matters. If the final, non-appealable resolution is to terminate the Contract, the Participants still may commence a cure within 60 days of the resolution. Participants must thereafter pursue the cure to completion, and the date for performance of any Mainline Entity and impacted Participants obligations is extended by a period equal to the length of the suspension.

The State may again 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.

D. Rights and Obligations Upon Termination. Project Entity agreements must allow the State's affiliate to dissolve the Project Entity if the Contract terminates before completion of the initial Open Season for the Mainline. If the Contract terminates after that Open Season, the State's affiliate may withdraw from each Project Entity.

ARTICLE 6: ALASKA HIRE AND CONTENT

1. **Purpose**. The Contract has been drafted to encourage the hiring of Alaska residents and businesses to the greatest extent legally permissible.

2. **Compliance with Laws**. Each Midstream Entity is required to comply with all laws that relate to the hiring of Alaska residents and business and must not discriminate against Alaska residents or Alaska businesses.

3. **Alaska Hire**. Each Midstream Entity must employ Alaska residents and contract with Alaska businesses to work on construction, fabrication, or operation of the Alaska Project to the extent such residents and businesses

   (i) are available and ready, willing and able to accept employment at the time required and are located anywhere in Alaska;

   (ii) offer goods and services at a total cost equal to or less than that offered by a non-Alaska resident or business; and

   (iii) possess the requisite resources, education, training, skills, certification and experience for a particular position or to perform the work in question.

4. **Recruitment**. Midstream Entities must advertise available positions to Alaska residents and businesses in the following manner:

   (i) Midstream Entities must use Alaska Job Service Organizations and offices recommended by the Alaska Department of Labor and Workforce Development (the “Labor Department”) to notify residents of available positions.

   (ii) Copies of each advertisement must be provided to the Labor Department, and the Labor Department may also publicly disseminate the information.

   (iii) A position is “available” if it is primarily or exclusively located within Alaska and the Midstream Entity intends to fill it with personnel not already employed by the Participants or their affiliates.

   (iv) Although a Midstream Entity is not required to advertise a position already offered to a candidate, the Contract contemplates that this exception will rarely be invoked.

5. **Training and Development Programs**. The Contract contains provisions intended to ensure that the Alaska Project expands the skilled workforce in Alaska through the provision of training opportunities to Alaska’s residents.

   (i) Each Midstream Entity is required to work with the State to develop the Alaska Natural Gas Pipeline Act pipeline training program and other programs to increase employee opportunities for Alaska residents;

(ii) Each Midstream Entity shall spend or cause the Participants to spend $5 million on workforce training programs and activities in Alaska. Such programs may include:

(a) Informing students in Alaska school districts about jobs needed for the Alaska Project, and the availability of apprenticeship, mentoring and internship opportunities related to the Alaska Project;

(b) working with Alaskan teachers to develop curricula relevant to the Alaska Project;

(c) supporting the Labor Department in developing training standards for jobs needed for the Alaska Project; and

(d) providing on-the-job training for employees hired by a Midstream Entity.

(iii) Once Project-related planning activities are completed, each Midstream Entity must provide the Labor Department with a description of services, jobs and skills required for the construction and operation phases of the Alaska Project.

6. **Reporting**. The State shall report on Alaska resident employment related to the Project, and each Midstream Entity shall facilitate this reporting by using the State's unemployment insurance compensation payroll reporting format, modified to identify persons who received Alaska earned wages as a result of being employed by the Midstream Entity.

7. **Contractors and Subcontractors**. Contractors and subcontractors must also comply with the provisions of Article 6 through the inclusion of provisions set forth in Exhibit E in all contracts and subcontracts.

8. **Remedies**. Any failure to comply with Article 6 does not constitute a material breach sufficient to terminate the Contract. If a Midstream Entity persistently and intentionally fails to comply with the terms of Article 6, that entity and the State shall agree on an appropriate remedy. If the State and the Midstream Entity are unable to agree, there will be a dispute. Any remedy could include increased training and process improvements, but no monetary damages or penalties.

9. **Severability**. If a court finds invalid any portion of Article 6, all other portions of Article 6, as well as the remainder of the Contract, remain in effect.

ARTICLE 7: STATE OWNERSHIP

1. **State Ownership and Option Percentages**. The Contract provides that the State, through State-owned entities, will hold an ownership interest or option for ownership with regard to the following components of the Project:

   A. GTP, Mainline and Alaska to Alberta Project. The State shall own 20% of each.

   B. Existing Units. The State shall own an interest equal to the expected throughput of State Gas in Gas Transmission Pipelines from the following already-existing Units:

      (i) Prudhoe Bay Unit;

      (ii) PTU;

      (iii) Kuparuk River;

      (iv) Duck Island;

      (v) Northstar;

      (vi) Milne Point;

      (vii) Colville River; or

      (viii) Badami Unit.

   C. NPRA Transmission Lines. The State shall own an interest in a Gas Transmission Pipeline to transport Gas originating from Properties west of the Kuparuk River boundary, including the National Petroleum Reserve Alaska, to a GTP or the Mainline if that transmission line is sanctioned before the Commencement of Commercial Operations, or an option to own if sanctioned after that date.

      (i) The State must provide notice of its intent to exercise its interest 10 days before completion of the initial Open Season for that line.

      (ii) The State must pay its proportionate share of costs plus interest under the relevant Project Entity agreement and be added as a member under the agreement.

      (iii) The State's ownership interest will be commensurate with the expected throughput of State Gas.

   D. NGL Plant. The State shall own 20% of any NGL plant located in Alaska.

   E. Alberta-Lower 48 Project. If newly-built, or acquired by any Person in which the affiliates of all the Producers have any ownership interest, the State shall have an ownership interest in the Alberta-Lower 48 Project commensurate with the expected throughput of State Gas.

2. **Ownership Commitment**.

A. Alcan Elements. The State shall retain its ownership interest in the Alcan Elements listed in paragraphs 1.A-D at least until the State Capacity Holder executes a binding precedent agreement to reserve Capacity for all of its expected throughput of State Gas for each respective element, plant or project in the initial Open Season.

B. Alberta-Lower 48 Project. The State shall retain its ownership interests in the Alberta to Lower 48 Project until the completion of that initial Open Season. If, however, it does not execute a binding precedent agreement to reserve Capacity for any State Gas in that initial Open Season, the State may withdraw from the Alberta to Lower 48 Project under the provisions of that Project Entity agreement.

ARTICLE 8: REGULATION OF AND ACCESS TO PROJECT FACILITIES AND DISPOSAL SERVICES

1. **Regulation**.

- Alaska Project: The Parties expect that regulation of the Mainline, Gas Transmission Pipelines and GTP will be governed and controlled exclusively by.

  (i) the Natural Gas Act, the Alaska Natural Gas Pipeline Act of 2004, other applicable federal law, and the Contract, or

  (ii) if federal law does not apply, commercial agreements between a Midstream Entity and shippers.

- Non-Alaska Project: Regulation of the Non-Alaska Project for shipment of Gas will be governed and controlled exclusively by,

  (i) applicable Canadian law for the Non-Alaska Project located in Canada and the Contract;

  (ii) federal law for the Non-Alaska Project in the Lower 48 and the Contract; or

  (iii) commercial agreements between the Non-Alaska Project Facilities and shippers.

- Parties' Agreement: The Parties will not seek additional, different or supplementary requirements for regulation or access to the Gas Transmission Pipelines, GTP, Mainline, any NGL Plant, or the Non-Alaska Project.

- Support of Regulation: The Participants and the State will seek the exclusive jurisdiction of the FERC and NEB in any agency or court proceeding. In the event the FERC doesn't assert jurisdiction over a Midstream Element within 15 months of an application, the Midstream Element may either:

  (i) terminate its participation in the Contract; or

  (ii) enter into a commercial agreement to govern and control the rates, terms, and conditions of access for use of the Midstream Element.

- State Regulation: While the Parties expect the Alaska portion of the Project to be regulated by FERC or commercial agreements, if FERC does not assert jurisdiction, no Party may seek or support the jurisdiction of the Regulatory Commission of Alaska ("RCA") over any aspect of the Project, because such jurisdiction could cause Loss to the Participants. The State will be responsible for reimbursing Participants for Loss (including cost of cover or transportation or other appropriate relief) if the RCA asserts jurisdiction and takes actions inconsistent with the principles of

(i) FERC policy for jurisdictional facilities, or

(ii) commercial agreements for non-jurisdictional facilities that result in a Loss to a Participant.

- Regulatory Intervention: The Contract does not affect the right of any Party to petition FERC or NEB to institute a proceeding, or to participate or intervene in a FERC or NEB proceeding, including tariff proceedings.

- Previously-Used Assets: The Participants shall follow FERC policy regarding treatment of previously-used assets for FERC ratemaking purposes.

- Seasonal Variable Capacity: If a Midstream Entity offers any Seasonal Variable Capacity, it must make that Capacity available notably to firm shippers on a non-discriminatory basis.

2. **Impurities**.

- GTP Services: A Midstream Entity that owns a GTP ("GTP Entity") shall seek FERC approval to offer, or if a GTP is not regulated by FERC, shall offer unbundled services to

  (i) remove Impurities;

  (ii) dehydrate and compress Impurities; and

  (iii) dispose of Impurities.

- Rates:

  (i) If the GTP is not regulated by FERC, the rate charged must be just and reasonable and based on cost of service. If the State does not agree that the rate is just and reasonable and based on cost of service, it may issue a notice of dispute.

  (ii) If the GTP is regulated by FERC, the rate to dispose of Impurities will be subject to FERC approval.

- Disposal Services: After consulting with Producers, the GTP Entity must select one or more Properties to evaluate for its potential use as a Disposal Property and request that the Working Interest owners of the selected Properties conduct engineering studies to assess options. If certain conditions are met, each Producer or affiliate holding a Working Interest in the relevant Property must vote its interest to approve an agreement with the GTP Entity to dispose of Impurities in that Property.

- Limitation on Offering Service: The GTP Entity is not required to offer a disposal service if certain conditions exist related to regulatory approvals.

- Working Interest Owner Services: If the Working Interest owners of a Property agree to return and dispose of Impurities from a GTP, each Participant that is a Working Interest owner in that Disposal Property must vote to allow the State to return and dispose of Impurities removed from Associated State Gas delivered to the GTP from that Property. The Impurity Disposal Fee (and other terms) offered to the State must be the same as those available to the Working Interest owners of the relevant Disposal Property.

- Third-Party Services: Under the Contract, each Producer or affiliate entering into an agreement to dispose of Impurities from a Property in a different Property must allow the State to do so also, and must offer the State the same Impurity Disposal Fee and related terms. However, if the State accepts that offer, it is bound by the relevant terms, including whether the Impurities are treated as indigenous.

3. **State-Initiated Expansion**. Subject to limitations, when a Person, including the State, is unable to secure additional Capacity from shippers or the Project Entity on a Midstream Element, the State may require the Project Entity to submit an application to FERC to expand that Midstream Element. The FERC application must include the basis for the expansion request, the name of the expansion shipper, the volumes or quantities to be treated or shipped, and any other volumes or quantities of which the State is aware, and the State must provide a copy of the expansion notice to each Participant.

- Upon receipt of the expansion notice, the Project Entity must post its contents on either its electronic bulletin board or an alternative mechanism used for communications with the shipping public, and shall "diligently" prepare a FERC application, if the State has not exercised its option under Article 8.7 within the prior 5 years, and the expansion:

  (i) is for at least 50,000 MCF per day in Capacity on a Gas Transmission Pipeline, or 125,000 MMBTU per day in Capacity on the Mainline or the GTP, for all of the expansion shippers combined (excluding any Producer's or its affiliates' volumes or quantities);

  (ii) does not require the Project Entity to construct or operate a lateral from the Mainline or Gas Transmission Pipeline;

  (iii) does not require the Project Entity to install one or more loops in excess of a total of 100 miles; and

  (iv) does not include a Producer's or its affiliates' volumes or quantities for purposes of Article 8.7(a)(i)(A) (see Item (i) above), but does include consideration of any Producer's, affiliates' or any other Person's volumes or quantities for purposes of designing an expansion under Article 8.7 and conducting an Open Season for that expansion.

- Another requirement is that the expansion shipper:

(i) meets the credit standards in the Midstream Element's tariff;

(ii) pays in advance all costs related to the filing of the application and costs related to activities required to complete the application;

(iii) obligates itself to submit in the Open Season a qualifying and responsive bid for Capacity in an amount equal to the volume or quantity identified in the expansion notice for that expansion shipper; and

(iv) is not a Producer or its affiliate.

- Still another prerequisite is that the Open Season results in the execution of negotiated rate agreements by all successful bidders for firm transportation service that are:

(i) consistent with the principles in Article 8.7(a)(iv), and

(ii) at rates that do not exceed the cost-of-service rate on a present value basis proposed in the Open Season bid package.

- Finally, the application must be filed consistent with the following principles:

(i) the rates for the expansion service must be designed to ensure the recovery of the cost associated with the expansion;

(ii) the rates, terms, and conditions for the expansion service must not require any existing shipper on the Project to:

(a) pay a higher Rate than it would have had to pay absent the expansion;

(b) be assessed a higher fuel retention percentage than would have been assessed absent the expansion; or

(c) otherwise subsidize the expansion.

(iii) all new shippers shall comply with terms and conditions consistent with the tariff of the Midstream Element currently in effect;

(iv) the proposed expansion facilities must not adversely affect the financial or economic viability of the Midstream Element;

(v) adequate downstream facilities must exist or are expected to exist to deliver the proposed expansion Gas to market;

(vi) the proposed expansion facilities must not adversely affect the overall operations of the Midstream Element;

(vii) the proposed expansion facilities must not diminish the contract rights of existing shippers to previously subscribed certificated Capacity; and

(viii) all necessary environmental reviews must be completed.

- Article 8.7 is effective unless FERC or NEB determines that any of its provisions are contrary to law.

- The Project Entity shall reject any certificate issued by FERC or NEB that is different than the relevant expansion proposal, unless the difference is minor or all members of the Project Entity vote otherwise.

- <u>Disputes</u>:

  (i) If the Midstream Entity to whom the expansion notice is directed believes that the requirements of Article 8.7(a) have not been satisfied, it shall provide notice to the State and the State may provide a notice of dispute.

  (ii) If the relevant Midstream Entity believes that the requirements of Article 8.7(a) have been satisfied, then another Party may dispute the expansion notice.

  (iii) The amicable dispute process under Section 2 of the mandatory dispute resolution procedures in Exhibit C does not apply to a dispute under Article 8.7.

  (iv) If a Project Entity breaches its obligations to submit a FERC application in accordance with Article 8.7, the State may issue a notice of dispute and seek an Award of specific performance from the Tribunal. The State's right to seek specific performance is its exclusive remedy for any breach of Article 8.7.

ARTICLE 9: IN-STATE MARKETS

1. **In-State Needs and Offtake Points**. At least 30 days before filing its plan for the initial Open Season, the Mainline Entity shall:

   (i) Complete or adopt a study of gas consumption needs and offtake points consistent with FERC requirements; and

   (ii) consult with the State on the location of the offtake points.

   In addition to those required by FERC or federal law, the Mainline Entity, if requested by the State, will support funding of up to 4 offtake points to accommodate in-State consumption.

2. **Open Season In-State Service**. During the initial Open Season, the Mainline Entity shall offer mileage-sensitive service to the offtake points designated in Article 9.1 (see above). Also, if requested by a shipper before a voluntary expansion Open Season, such service shall be offered to an offtake point designated under Article 9.1. In addition, the Mainline Entity must propose tariff provisions providing for segmented Capacity consistent with FERC procedures, so that a shipper may use its firm transportation services to offtake points provided they are upstream of the firm contracted service point.

3. **In-State Distribution Systems**. The Contract does not require any Party to fund, install, and maintain any facilities downstream of any offtake point. Any such 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 offtake point in the planning and design of such facilities, consistent with FERC policy.

4. **In-State Gas Sales Contracts**. Any Party may, but is not required to, sell Gas to an Alaskan purchaser. Additionally, 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). 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.

5. **NGL Study**. Before the commencement of the initial Open Season, the Mainline Entity must conduct a feasibility study of NGL processing opportunities in Alaska.

ARTICLE 10: CAPACITY

1. **Capacity Acquisition Process**.

- The State Capacity Holder must notify each Producer Capacity holder at least 30 days before the end of an Open Season that:

  (i) it intends to acquire Capacity on its own, or

  (ii) the Producer Capacity Holder should seek to acquire State Capacity on the State Capacity Holder's behalf, including the amount to acquire.

- If the State Capacity Holder requests each Producer Capacity Holder to acquire State Capacity, to the extent the Producer Capacity Holder is successful, the Producer Capacity Holder must acquire Capacity (i) in proportion to the State Export Gas attributable to the Producer Gas, (ii) on the same terms and conditions sought by the Producer Capacity Holder, and (iii) at the State Capacity Holder's sole risk and cost.

- Within 90 days after the acquisition of State Capacity, the Producer Capacity Holder will provide a notice ("Capacity Notice") to the State Capacity Holder specifying the amount, duration and terms and conditions of acquired Capacity.

- The State may acquire State Capacity on its own for in-State need in any Open Season 30 days or more after the State provides notice of this intent.

- The State also has the option to acquire on its own Capacity needed for export of State Gas, but if it does so, the provisions of Article 10 terminate.

2. **Situations Where State Has Insufficient Capacity**

- If a Producer plans to deliver State Gas greater than the amount of State Capacity identified in the Capacity Notice (e.g., a new field starts production), then the Producer Capacity Holder must satisfy the State's additional Capacity need through one or more of five listed options.

- After utilizing one or more of the five options, the Producer Capacity Holder must send the State an amended Capacity Notice identifying the amount of additional Capacity the State has acquired or other type of action taken (e.g., purchase of State Gas).

3. **Situations Where State Has Excess Capacity**.

- If a Producer Capacity Holder seeks to purchase Gas from a third party to ship on its Excess Property Capacity, it shall offer the State Capacity Holder the opportunity to participate in the transaction, thus allowing the State the opportunity to reduce any excess Capacity.

- If a Producer Capacity Holder seeks to release some of its Excess Property Capacity, it shall offer the State Capacity Holder the opportunity to release a portion of its excess Capacity.

- For these transactions, the Producer Capacity Holder must provide the State Capacity Holder a range of target terms, conditions and pricing for the gas purchase ("Purchase Range"), or a range of terms, conditions and pricing for the release posting ("Capacity Range").

- If the State Capacity Holder accepts the Purchase Range, then the Producer Capacity Holder shall purchase the State Capacity Holder's share of the purchased Gas at the State's sole cost and expense.

- If the State Capacity Holder accepts the Capacity Range, the Producer Capacity Holder shall include the appropriate State Capacity Holder's share of Capacity in a Capacity release posting.

- If the State Capacity Holder rejects either of these offers, most of the Producer Capacity Holder obligations under Article 10 terminate.

4. **"Putting" Capacity To Handle Situations of Excess Capacity**

- The Contract provides an additional important method, the put method, for the State to mitigate the financial impacts of excess Capacity.

- Each Producer Capacity Holder must provide a monthly notice to the State Capacity Holder of the Takeaway Ratio and the Forecast Ratio for each Alcan Element by Property.

- If the Takeaway Ratio is greater than the Forecast Ratio, then the State Capacity Holder shall release sufficient Capacity to make those ratios equal, and the Producer Capacity Holder shall acquire that released Capacity.

- If the Takeaway Ratio is less than the Forecast Ratio, then the Producer Capacity Holder shall release sufficient Capacity to make those ratios equal, and the State Capacity Holder shall acquire that released Capacity.

5. **Information Sharing**. If a Producer Capacity Holder receives information that is related to expected deliveries of State Gas to the Project from an Operator or the Producer Capacity Holder's Producer or production forecast information from an Operator related to expected deliveries of Gas that would materially impact its Producer Capacity Holder's Capacity, that information must promptly be provided to the State Capacity Holder.

6. **Termination**. The circumstances under which the Capacity provisions may be terminated are set forth in detail in Article 10.8, and include the State Capacity Holder's right to provide notice to terminate the provisions for any reason.

7. **Remedies and Damages**. Because the State is not required to compensate any Producer Capacity Holder for acquiring State Capacity, the State cannot seek damages with regard to Capacity disputes, except in the case of fraud; its exclusive remedy is to seek specific performance.

ARTICLE 11: FISCAL STABILITY

1. **Satisfaction of Fiscal Obligations**.

   - Royalty. By making the Royalty payments under Article 12, each Producer and its affiliates satisfy their entire Royalty obligation on Royalty Bearing Gas.

   - Tax. By making payments under Articles 11-17, the Project, the Properties, and each Participant and its affiliates (and their interests with an Alaska nexus), are exempt from, and those payments are in lieu of, any Tax on their oil or gas related business activity in Alaska, except for a:

     (i) Capped Tax under the Fiscal Stability Tax; and

     (ii) Fixed Payable Tax under Article 11.4.

2. **Covenant**. In consideration of the obligations of each Participant under the Contract, the State covenants to provide fiscal certainty for each Participant's Interest on its oil or gas related business activity in Alaska for the term of the Contract – generally, 35 years from the Commencement of Commercial Operations [except for oil].

3. **Taxes Levied by the State**.

   - A Participant shall pay (i) the portion of the cumulative annual total of Capped Taxes less than or equal to the amount of the Fiscal Stability Cap, or (ii) a Fixed Payable Tax, except for a Fixed Payable Tax Increment under Article 11.4(a) (See Item 5 below).

   - Each Participant is exempt from all Taxes levied by the State on their oil or gas related business, except for those Taxes identified in Item 3, immediately above.

4. **Taxes Levied by a Political Subdivision**.

   - A Participant shall pay (i) the portion of the cumulative annual total of Capped Taxes less than or equal to the amount of the Fiscal Stability Cap, or (ii) a Fixed Payable Tax, except for a Fixed Payable Tax Increment under Article 11.4(a) (See Item 5 below).

   - Each Participant is exempt from any (i) Restricted Tax, or (ii) portion of the cumulative annual total of all Other Taxes on a Participant's Interests greater than $10 million, inflated, except for those Taxes identified in Item 4 above.

   - For certain Taxes, a Participant may exercise its exemption only by paying the Tax to the Political subdivision and then obtaining reimbursement from the State under Article 22.

5. **Fixed Payable Tax Increments**.

- Change in Vessel Tax. A change in the rate or application, including a change in valuation methodology, of a Vessel Tax may cause a positive or a negative Fixed Payable Tax Increment, thereby causing the Participant, its affiliate, or a contractor or subcontractor of a Participant or its affiliate to be eligible for reimbursement or to be liable for additional payment.

- Change in Mill Rate. If the combined State and Political Subdivision mill rate does not exceed 20 mills, a mill rate change does not create a Fixed Payable Tax Increment. If it exceeds 20 mills, the increment above 20 mills enters into the calculation of a Fixed Payable Tax Increment.

6. **Non-Participant Reimbursable Tax**. Personal income and withholding tax, or SCIT paid by a contractor or subcontractor, is not a Participant obligation. If, however, one or both of those taxes is not a Third Party Payable Tax and results in Loss to a Participant, the Participant may obtain reimbursement from the State for the Loss under Article 22.

7. **Targeted Tax Audit**. In order to determine whether a Tax is a Targeted Tax, a Participant may request an independent audit of relevant records of the State or Political Subdivision.

8. **Certificates of Exemption**. The Commissioner of Revenue shall provide a Participant or its affiliates with an Exemption Certificate to facilitate an exemption from a State Tax.

9. **Non-Participant Taxes**. Contractors and Subcontractor and a Participant's or its affiliate's contractors or subcontractors receive no Tax exemption under the Contract. However, they may use an Exemption Certificate to the extent the certificate is used on behalf of the Participant or its affiliate in association with the Project, or in association with the Properties.

10. **Interest**. Amounts paid or reimbursed are subject to Interest.

11. **Disputes and Audits**.

- Audits and disputes between a Participant and a Political Subdivision are not governed by the Contract.

- Except for items listed in Exhibit B.3(a)(iii) and (iv), all audits and disputes regarding Taxes are matters of Contract interpretation and are subject to Articles 25 or 26. Attachment 4 contains an example of the application of Article 11.12(a).

- If the State disagrees with the amount of a tax levied by a Political Subdivision on a Participant or a Participant's or its affiliate's contractor or subcontractor, the State shall provide notice to the Participant, in which case the Participant shall either defend against the tax or request that the State defend and indemnify the Participant.

- A Tribunal may not give any deference to any findings, decision, including a court decision, or position by or applicable to a Political Subdivision.

ARTICLE 12: ROYALTY PAYMENTS

1. **Royalty Payments**. A Producer's Royalty Bearing Gas is subject to Royalty Payment only once, except that later reproduced Impurities are subject to Royalty Payment if they are indigenous to a Disposal Property. Example calculations of Royalty Payments are shown in Exhibit F.

2. **Method of Royalty Payment Before Commencement of Commercial Operations**. For the properties listed in Exhibit D, a Producer has the following Royalty Payment obligations prior to Commencement of Commercial Operations:

   - Fixed Royalties:

     - For all Royalty Bearing Gas delivered to a Delivery Point into a Midstream Element, a Producer must make its Fixed Royalty Payment to the State in kind if (i) the Producer in the Property is injecting Royalty Bearing Gas into another Property and (ii) that Producer includes provisions in its Gas injection agreement that treat Royalty Gas in the same manner as the Producer's Royalty Bearing Gas.

     - For all Royalty Bearing Gas that is delivered to a Delivery Point but not to a Midstream Element, the State will receive its Fixed Royalty as it is provided in the applicable lease or other agreements in effect on October 1, 2005.

   - Incremental Royalties: For all Royalty Bearing Gas delivered to a Delivery Point, the State will receive its Incremental Royalties as described in Item 4 below.

   - Royalties for Line Pack: For all Royalty Bearing Gas that is delivered by a Producer to the Mainline, the GTP, or a Gas Transmission Pipeline for line pack, the State will receive its entire Fixed Royalty in cash value. The payment amount equals the product of the actual proceeds received by the Producer from each line pack transaction multiplied by the Fixed Royalty share for the Property where the Gas came from.

3. **Method of Royalty Payment After Commencement of Commercial Operations**. For the properties listed in Exhibit D, a Producer has the following Royalty Payment obligations after Commencement of Commercial Operations:

   - Fixed Royalty in Kind: For all Royalty Bearing Gas that is delivered to a Delivery Point, the Producer will make its Royalty Payment to the State in kind at the Delivery Point into a Midstream Element.

   - Incremental Royalties: For all Royalty Bearing Gas delivered to a Delivery Point, the State will receive its Incremental Royalties as described in Item 4 below.

   - If a Producer's total volume of Royalty Bearing Gas delivered into the Mainline each month for 12 consecutive months, less any Impurities, fuel, and losses, is less than 95% of the total volume of Royalty Bearing Gas delivered by that Producer for each of those 12 months, then the State has the following one-time option. For the Producer's Royalty Bearing Gas that is not delivered to a Midstream Element, the State has the option to (i) continue to take Royalty in kind, (ii) take its Royalty under the applicable lease or settlement agreement in effect on October 1, 2005, or (iii) make another mutually-agreeable arrangement with the Producer.

- If the State makes an election discussed in the previous paragraph, it must give notice to the Producer, specify an effective date for the election, and specify the deliveries that are covered by the election.

4. **State's Royalty Share**.

- Fixed Royalty Rate Properties: After Commencement of Commercial Operations, the State's Royalty on all Royalty Bearing Gas is the total volume of the Royalty Bearing Gas that is delivered to a Delivery Point multiplied by the applicable Fixed Royalty percentage (which is specified in the lease, Unit or settlement agreement for the relevant Property).

- Incremental Royalty Properties: For a Property with an Incremental Royalty, the Producer must make its Royalty Payment to the State based on the methodology specified in the applicable lease, Unit or settlement agreement for that Property, unless the Producer makes the election for sliding scale leases provided in Article 12.2(c) as described immediately below.

- Conversion: To make an election to convert a sliding scale obligation into a Fixed Royalty percentage obligation, the Producer must give notice that it intends to make the election. The conversion is based on published crude oil prices, must take place within 3 months of the notice, and becomes effective only if deliveries of Royalty Bearing Gas begin within 365 days after the notice.

5. **Title Transfer and Disposition of Gas**.

- For each Property, the State takes delivery of its Royalty Gas at the Delivery Point into the Midstream Element that is immediately downstream from that property. The State takes full ownership, title, financial responsibility and risk of loss for its Royalty Gas at the Delivery Point in its then-current composition, condition or quality.

- The State is responsible for the transportation, tendering, treating, processing, marketing, and sales, use, or disposition of the Royalty Gas as it is delivered.

- In making arrangements for the disposition of a Party's Gas, all Parties have the same rights and obligations regarding their Gas. However, a Party may not unreasonably interfere with any other Party's disposition of Gas, nor require another Party to install special facilities to handle Gas.

- A Party may authorize a Person to act on its behalf regarding its rights and obligations under Article 12, but the Party is still directly liable to the other Parties for any defect or failure by that authorized Person.

6. **<u>Disposition of Impurities</u>**.

- Each Party is responsible for the removal, dehydration, compression and disposal of Impurities in its Gas.

- For purposes of determining obligations regarding Impurities, Impurities that are disposed of in a Disposal Property are treated:

  - as indigenous to that Disposal Property for Impurities that originate from that Disposal Property; or

  - in the same manner as the Producers who are Working Interest owners of the Disposal Property treat Impurities that do not originate from that Disposal Property.

ARTICLE 13: TAX BEARING GAS PAYMENT

1. **Tax Bearing Gas Election**. The State elects, by signing the Contract, to receive its Tax Bearing Gas Payment in kind instead of a cash payment (except as provided below), as a share of each Producer's Tax Bearing Gas.

2. **Tax Bearing Gas Payment**.

   - Each Producer must make a Tax Bearing Gas Payment to the State for each Property. A Producer's Tax Bearing Gas is subject to a Tax Bearing Gas Payment only once, except that later reproduced Impurities are subject to a Tax Bearing Gas Payment if they are indigenous to a Disposal Property. The payment is a fixed percentage (7.25%) of the Tax Bearing Gas Value received by the Producer for its Tax Bearing Gas from a Property. Example calculations of Tax Bearing Gas Payments are shown in Exhibit F.

   - The Tax Bearing Gas Value equals the volume (in thousand cubic feet) measured at a Delivery Point multiplied by the Heating Value of the Gas at the Delivery Point, with that product then multiplied by the Tax Bearing Gas Price that is applicable to that Delivery Point.

     - The Tax Bearing Gas Price is determined every calendar month. The price equals the Alberta Energy Co. monthly index of Gas price less the Alaska to Alberta Tariff.

3. **Tax Bearing Gas Payment Before Commencement of Commercial Operations**. For each Property, a Producer has the following Tax Bearing Gas Payment obligations prior to Commencement of Commercial Operations:

   - For all Tax Bearing Gas delivered to a Delivery Point into a Midstream Element, a Producer must make its Tax Bearing Gas Payment to the State in kind as Tax Gas (not cash) if (i) the Producer in the producing Property is injecting Tax Bearing Gas into another Property, and (ii) that Producer includes provisions in its Gas injection agreement that treat Tax Gas in the same manner as the Producer's Tax Bearing Gas is treated.

   - For all Tax Bearing Gas that is delivered to a Delivery Point, but not to a Midstream Element, the State will receive its Tax Bearing Gas Payment on the Tax Bearing Gas as provided in the applicable laws that were in effect [on October 1, 2005].

   - For all Tax Bearing Gas that is delivered by a Producer to the Mainline, the GTP, treatment plant facility, or a Gas Transmission Pipeline for line pack, the State will receive its entire Tax Bearing Gas Payment based on the actual proceeds received by the Producer from each line pack transaction for the volume of Tax Bearing Gas multiplied by the Tax Bearing Gas Percentage for the Property where the Gas came from.

4. **Tax Bearing Gas Payment After Commencement of Commercial Operations**. For each Property, a Producer has the following Tax Bearing Gas Payment obligations after Commencement of Commercial Operations:

- For all Tax Bearing Gas that is delivered to a Delivery Point, the Producer will make its Tax Bearing Gas Payment in the form of Tax Gas.

- If a Producer's total volume of Tax Bearing Gas delivered into the Mainline each month for 12 consecutive months, less any impurities, fuel, and losses, is less than 95% of the total volume of Tax Bearing Gas delivered by that Producer for each of those 12 months, then the State has the following one-time option. For the Producer's Tax Bearing Gas that is not delivered to a Midstream Element, the State has the option to (i) continue to take Tax Gas in lieu of cash, (ii) take its Tax Gas in cash value, (iii) treat the Tax Gas as provided by applicable law, or (iv) make another mutually-agreeable arrangement with the Producer.

- If the State makes an election discussed in the previous paragraph, it must give notice to the Producer, specify an effective date for the election, and specify the deliveries that are covered by the election.

5. **Title Transfer and Disposition of Gas**.

- For each Property, the State takes delivery of its Tax Gas at the Delivery Point into the Midstream Element that is immediately downstream from that Property. The State takes full ownership, title, financial responsibility and risk of loss for the Tax Gas at the Delivery Point in its then-current composition, condition or quality.

- The State is responsible for the transportation, tendering, treating, processing, marketing, and sales, use, or disposition of the Tax Gas as it is delivered.

- In making arrangements for the disposition of a Party's Gas, all Parties have the same rights and obligations regarding their Gas. However, a Party may not unreasonably interfere with any other Party's disposition of Gas, nor require another Party to install special facilities to handle Gas.

- A Party may authorize a Person to act on its behalf regarding its rights and obligations under Article 13, but the Party is still directly liable to the other Parties for any defect or failure by that authorized Person.

6. **Disposition of Impurities**.

- Each Party is responsible for the removal, dehydration, compression and disposal of Impurities in its Gas.

- For purposes of determining obligations regarding Impurities, Impurities that are disposed of in a Disposal Property are treated:

- as indigenous to that Disposal Property for Impurities that originate from that Disposal Property; or

- in the same manner as the Producers who are Working Interest owners of the Disposal Property treat Impurities that do not originate from that Disposal Property.

ARTICLE 14: PAYMENTS IN LIEU OF PRODUCTION TAXES

This Article and Exhibit P will be finalized after the Alaska Legislature enacts a certain legislation.

ARTICLE 15: UPSTREAM FACILITIES PAYMENTS

1. **Upstream Facilities Payment**. A Producer must make an annual payment on its interests in each Upstream Facility (a facility upstream of a Delivery Point). These Upstream Facilities Payments must be paid in accordance with the accounting procedures in Exhibit A. Example calculations are shown in Exhibit F.

2. **Upstream Facilities Oil Payment**. Each Producer shall make an annual Upstream Facilities Oil Payment on the Producer's interests in each Upstream Facility. That payment equals a Producer's barrels of Hydrocarbon Liquids originating from a Property and measured for delivery to TAPS, multiplied by specified per barrel amounts for each Unit (e.g., $0.500 per barrel for PTU).

    - If the property was producing on the Effective Date of the Contract, then for any payment due in 2006 or 2007, the number of barrels used is the average of the total barrels of Hydrocarbon Liquids delivered to an Oil Pipeline for the prior 5 calendar years. For any payment due after 2007, the number of barrels used is the average number of barrels delivered for the prior 3 calendar years.

    - If the property was not producing as of the Effective Date, the volume used for the first 5 years of production is the total number of barrels delivered into an oil pipeline for the prior calendar year. After the fifth year, the volume is the annual average number of barrels delivered for the prior 3 calendar years.

3. **Upstream Facilities Gas Payment**. Each Producer shall make an annual Upstream Facilities Gas Payment on the Producer's interests in each Upstream Facility. That payment equals the sum of the volume of Producer Gas, Associated State Gas, and other royalty Gas associated with that Producer originating from a Property and measured at the Delivery Point, multiplied by $0.021 per MCF.

    - For the first 5 years of production, the volume of Gas for the calculation is the sum of the volumes for the prior calendar year of Producer Gas, Associated State Gas, and any other royalty Gas associated with the Producer, as measured at the Delivery Point.

    - Thereafter, the volume of Gas for the calculation is the annual arithmetic average of the sum of the volume of Producer Gas, Associated State Gas, and other royalty Gas associated with that Producer, measured at the Delivery Point for the prior 3 calendar years.

4. **Payment Date**. The payment date for the Upstream Facilities Oil Payment depends on whether the Property was producing Hydrocarbon Liquids as of the Effective Date of the Contract. The payment date for the Upstream Facilities Gas Payment depends on the date of Commencement of Commercial Operations of the gas pipeline.

5. **Inflation Adjustment**. Both types of Upstream Facilities Payments are adjusted annually for inflation as described in Article 36.1 beginning in 2007. The adjusted rates are effective as of January 1 of the applicable year.

6. **Third Parties**. Only Parties with Working Interests in an Upstream Facility are exempt from any property tax payment on that Upstream Facility. If a third party delivers Hydrocarbon Liquids or Gas into an Upstream Facility that they do not have a Working Interest in, the owner of that Upstream Facility must make additional Upstream Facilities Payments for the Hydrocarbon Liquids or Gas delivered by the third party, unless an agreement regarding the processing of those Hydrocarbon Liquids or Gas was entered into before the Effective Date.

ARTICLE 16: MIDSTREAM PAYMENT

1. **Annual Payments**. Each Project Entity owning a Midstream Element (a Gas Transmission Pipeline, a GTP, the Mainline, or an NGL Plant located in Alaska) must make an annual payment on each of its Midstream Elements. The first payment is due on the last business day of June in the year after the year that Gas is first delivered into a Midstream Element. The annual payment must be paid in accordance with the accounting procedures in Exhibit A.

2. **Payment Calculation**. The amount of the payment is determined as follows:

   - For the Mainline, $0.024 per MMBTU multiplied by the quantity of Gas measured at the meter where the quantity is delivered into the Mainline;

   - For the GTP on the ANS, $0.010 per MMBTU multiplied by the quantity of Gas measured at the meter where the quantity is delivered into the Mainline from the GTP; and

   - For each Gas Transmission Pipeline, $0.0003 per MCF–mile multiplied by the sum of each volume of Gas measured at the meter at the Inlet Point, and then multiplied by the Segment Length for that portion of the pipeline associated with that meter at the Inlet Point.

3. **Determination of Quantities and Volume**. For the first 5 annual Midstream Payments, the quantity or volume of Gas to be used in the calculation of the Midstream Payment is the total quantity or total volume of Gas delivered into that Midstream Element for the prior calendar year. For every annual payment thereafter, the quantity or volume of Gas to be used in the calculation is the average of the total quantity or volume of Gas delivered into that Midstream Element for the prior 3 calendar years.

4. **Inflation Adjustment**. The rates used to calculate the Midstream Payments are adjusted annually for inflation as described in Article 36.1 . The adjusted rates are effective as of January 1 of the applicable year.

5. **Additional Midstream Facilities**. If a Project Entity acquires an additional Midstream Element, the rate used to calculate the Midstream Payment will be determined by the agreement of the Parties.

6. **Ceased Operations**. If a Midstream Element ceases operation, then the final payment is due on the last business day of June in the year following the date of cessation. If the Midstream Element resumes operation, the payments will also resume.

ARTICLE 17: PAYMENTS IN LIEU OF OIL PIPELINE AD VALOREM TAXES

1. **Payments in Lieu of Oil Pipeline Ad Valorem Taxes**. Each year, beginning as of the Effective Date of the Contract, each Participant will make payments in lieu of oil pipeline ad valorem taxes to the State under Article 17 for each ANS oil pipeline in which it holds an ownership interest. The provisions for these payments do not apply after December 31, 2035 unless the State and the Participants mutually agree to extend them. The payments provided for in Article 17 are subject to the conditions contained in Exhibit A (accounting procedures) and Exhibit G (payments to Political Subdivisions and the State). An example calculation of the payment is shown in Exhibit F.

2. **Payment Amount**. The amount of the payment to the State is determined by whether the pipeline has begun to transport unrefined oil as of the valuation date (January 1 of a calendar year).

   - If the pipeline has not yet begun to transport unrefined oil as of the valuation date, then the payment amount is the Participant's ownership interest in the pipeline multiplied by the actual cost of the pipeline as of the valuation date (all costs incurred except for interest capitalized before or during construction), multiplied by 2%.

   - If the pipeline has begun transporting unrefined oil as of the valuation date, the payment amount is the average annual barrels of oil tendered into the pipeline, multiplied by the Participant's ownership interest in the pipeline, multiplied by a per-barrel dollar amount that depends on the particular pipeline.

3. **Determination of Oil Pipeline Volumes**. For the purposes of calculating the payment amount, the number of barrels of oil is determined on the valuation date of each calendar year.

   - For the first calendar year after the pipeline begins transporting unrefined oil, the number of barrels to be used in the payment calculation is the number of barrels tendered into the pipeline in the previous calendar year.

   - For the second calendar year after the pipeline begins transporting unrefined oil, the number of barrels to be used in the payment calculation is the average number of barrels tendered into the pipeline for the previous two calendar years.

   - For the third calendar year after the pipeline begins transporting unrefined oil, and for every calendar year thereafter, the number of barrels to be used in the payment calculation is the average number of barrels tendered into the pipeline for the previous three calendar years.

4. **Ceased Operation**. If the pipeline ceases operation, the final payment for that oil pipeline is the payment that was due on or before the last business day of June in the year of cessation. If the pipeline resumes operation, each Participant or affiliate owning an interest in the pipeline must resume payment.

5. **Notice of Actual Cost**. On or before February 15 of each calendar year, each Participant or affiliate owning an interest in an oil pipeline that has not begun to transport unrefined oil must provide a notice of all costs incurred in the construction of the pipeline as of the valuation date (January 1). On or before April 15 of each calendar year, the Commissioner of DOR will provide to the Participant or affiliate a notice of actual cost of that oil pipeline as of the valuation date, which will be used in the calculation of the payment amount. The actual cost amount will be deemed correct until any dispute is final.

6. **Inflation Adjustment**. The dollar-per-barrel and the dollar-per-barrel-per-mile rates that are specified in Article 17 for purposes of payment calculation will be adjusted annually for inflation. The adjustment methodology is described in Article 36. The adjusted rates are effective on January 1 of the applicable calendar year.

7. **Third Parties**. The Contract exempts only an oil pipeline ownership interest from any property tax payment on that ownership interest under applicable law. To the extent that a Participant is operating an oil pipeline on behalf of a non-Participant, this Contract does not exempt the Participant from the reporting requirements under the law.

ARTICLE 18: IMPACT PAYMENTS

1. **Impact Payments**. The Mainline Entity is required to make payments to the State, adjusted for inflation pursuant to Article 36.1(d), to address the economic and social impact of the Project, and to do so according to the following schedule:

   - $8.9 million payable at the end the calendar year immediately following Project Sanction ("Initial Impact Payment Date");
   - $16.6 million payable 1 year following the Initial Impact Payment Date;
   - $27.7 million payable 2 years following the Initial Impact Payment Date;
   - $27.7 million payable 3 years following the Initial Impact Payment Date;
   - $26.0 million payable 4 years following the Initial Impact Payment Date; and
   - $18.1 million payable 5 years following the Initial Impact Payment Date.

2. **Suspension or Termination**.

   - The amount or timing of the above payments may not be changed unless (i) the Mainline Entity suspends its obligations in accordance with the Contact, or (ii) the Contract is terminated.
   - If the Mainline Entity suspends its obligations, it may suspend making Impact Payments for the remainder of the suspension period beginning 1 year after a Judicial Suspension Notice or a notice of Force Majeure.
   - If the Contract is terminated, then the Mainline Entity's obligations to make any unpaid Impact Payments is likewise terminated.

ARTICLE 19: PAYMENT IN LIEU OF STATE CORPORATE INCOME TAX

1. **Payment in Lieu of SCIT**. Under Article 19, each Participant and each of its affiliates with an Alaska nexus must submit consolidated tax returns and make payments to the State in lieu of state corporate income tax ("SCIT"). Each Participant will make estimated payments in lieu of SCIT as provided in the Alaska Statute and the Internal Revenue Code. Example calculations of the payment in lieu of SCIT are shown in Exhibit F.

    - Under the Alaska Statutes, the payment in lieu of SCIT under Article 19 is deemed to be a tax based on, or measured by, net income.
    - The due dates for the estimated payments are the last day of the 4th, 6th, 9th, and 12th months of the SCIT calendar year. The consolidated return and any unpaid balance are due by the end of the 4th month following the end of the SCIT calendar year.
    - If there is any amount due when the return is filed, the amount due must be included in the end-of-the-month payment in the month that the return is filed. Any interest due will be determined under the interest provisions of Article 33.
    - Any audits relating to payments in lieu of SCIT are subject to the audit provisions contained in Article 25 and Exhibit B.
    - The State may not claim or assert any penalty provided for in the text of a State law or the Internal Revenue Code that was incorporated by reference into Article 19.

2. **Incorporation and Modification of State Laws and Federal Income Tax Law**.

    - Article 19 incorporates by reference the text of Articles I, II, IV and XII of AS 43.19010 (Multistate Tax Compact), and AS 43.20, 15 AAC 19 and 15 AAC 20 as they read on October 1, 2005, except for any provisions relating to audit.
    - Article 19 also makes several modifications to the State laws that are incorporated by reference. The modifications are listed in Article 19.1(b).
    - With respect to each State law whose text is incorporated by reference, the judicial interpretation of the text rendered by the courts or an administrative law judge that was in effect on October 1, 2005 will apply to the Contract.
    - The sections of the Internal Revenue Code that are referred to in any State law that is incorporated by Article 19 will also apply in determining the payments in lieu of SCIT for that SCIT calendar year. Federal decisions, orders, regulations, or rulings that interpret or apply any provision of the Internal Revenue Code that is adopted by Article 19 will also apply in interpreting or applying that provision.

3. **Presumptions and Interpretations**. Any presumption created under the laws that are incorporated into the Contract will also be adopted as part of the Contract, except that the State's determination of a Tax under the laws adopted under Article 19 or its interpretation of a law will neither be presumed correct nor entitled to deference.

4. **Tax Bearing Gas Payment Impact on Payment in Lieu of SCIT**. A Producer's payment of a Tax Bearing Gas Payment or the transfer of a quantity or volume of Tax Gas must not be included in the calculation of the payments in lieu of SCIT that are otherwise payable under Article 19, irrespective of the individual Producer's internal reporting treatment.

5. **Impact of Cost Allowances on Payment in Lieu of SCIT**. Neither the UCA (described in Article 20) nor the field cost allowance may be included in the calculation of the payment in lieu of SCIT.

6. **Fundamental Changes to the Federal Income Tax System**. If the federal income tax system fundamentally changes so that it is no longer based on, or measured by, net income, then the Parties will propose alternative methods of calculating the payment in lieu of SCIT on the basis of net income. If there is a dispute regarding the alternate method of calculating the payment, the Parties' intent is that the method be based on, or measured by, net income in a way that is substantially similar to the federal income tax system that existed before the change. However, the Parties should not create an alternative method that requires maintaining and auditing special books and records that are kept solely for the purpose of calculating the payments in lieu of SCIT.

7. **Tax Periods Prior to Effective Date**. The provisions contained in the Contract for payments in lieu of SCIT have no effect on tax obligations under the Alaska Statute for SCIT calendar years before the Effective Date of the Contract other than the calendar year in which the Effective Date of the Contract occurs, or the Participant otherwise becomes a Party.

8. **Effective Tax Year of Payment in Lieu of SCIT**. Any estimated SCIT payments made by a Participant before the Effective Date of the Contract or before the date it becomes a Party will be treated as estimated payments in lieu of SCIT for that portion of the calendar year, and no SCIT will be due for that SCIT calendar year.

ARTICLE 20: COST ALLOWANCES

1. **State Payment Obligation**. As reimbursement for the Producers' upstream costs, the State will make an upstream cost allowance payment ("UCA") to each Producer of $0.2240 per MCF of State Gas that is delivered by the Producer at a Delivery Point or recouped as described in Article 22.2 (State payments to Midstream Entities). However, the State shall not pay the UCA for any Gas that is not subject to an Upstream Facilities Gas Payment (see Article 15).

    - Upstream costs include direct and indirect costs for gathering, separating, cleaning, dehydrating, compressing and other field handling costs associated with the production of State Gas upstream of a Delivery Point.

    - Upstream costs also include capital expenditures, operating expenses and overhead incurred by each Producer.

    - The amount of State Gas used in calculating the UCA amount includes any volumes of Gas attributable to Impurities that are disposed of in a Disposal Property and subsequently returned to the surface during Gas production operations.

2. **Existing Oil Lease Agreements**. For the Properties listed on Exhibit D that have a cost allowance on royalty oil or other Hydrocarbon Liquids production, the State will pay each Producer the cost allowance under the applicable lease or other agreement for that Property that is in effect on the Effective Date of the Contract.

3. **Inflation Adjustment**. The UCA amount will be adjusted annually for inflation, as specified in Article 36.1(a).

ARTICLE 21: PAYMENTS TO POLITICAL SUBDIVISIONS

1. **Political Subdivision/State Payment Split**.

- Political Subdivisions are municipalities, boroughs, cities, or other local government units of the State of Alaska that are granted the power to impose taxes under the Alaska Constitution, and that are in existence on or after October 1, 2005.

- A Participant will make a portion of its payments due to the State under Articles 15, 16, and 17 payable to a Political Subdivision, with the remaining portion payable to the State. The apportionment of the payments is described in detail in Exhibit G.

  (i) Before March 1 of each calendar year, the Mainline Entity, each Project Entity that owns a Gas Transmission Pipeline , and each Participant or affiliate that owns an oil pipeline must provide to the State the mileage of its pipeline in each Political Subdivision, reflecting the mileage as of December 31 of the previous calendar year.

  (ii) Before May 1 of each calendar year, the State will determine and provide notice to each Producer, Midstream Entity, and Producer affiliate the ratios to be used in apportioning the payments to the Political Subdivisions.

  (iii) On or before the last business day of June of each calendar year, each Participant with payments due to the State (as described above) must make the portion payable to the Political Subdivision and any remaining portion payable to the State.

  (iv) Example calculations of amounts payable to Political Subdivisions are shown in Exhibit F.

2. **New Political Subdivisions**. The fiscal obligations under the Contract do not change as a consequence of the addition of payments to a new Political Subdivision. If a new Political Subdivision is formed after the Effective Date of the Contract, the State may provide notice to a Participant that a portion of the payments due to the State should be made payable to that new Political Subdivision, with the remaining portion payable to the State.

3. **Indemnification and Recourse**.

- A Political Subdivision has no right under the Contract to institute any administrative, judicial or arbitration proceeding against any Participant regarding the performance of the Contract, nor does it have any third party beneficiary rights under the Contract. A Political Subdivision's only recourse is against the State.

- The State will indemnify, hold harmless, and defend each Participant against any Loss resulting from claims by a Political Subdivision relating to the Participant's Fiscal Obligations. The State also will support any Participant's effort to participate in any administrative, judicial, or arbitration proceeding regarding the allocation or distribution of payments under the Contract.

ARTICLE 22: PAYMENT OF FISCAL OBLIGATIONS

1. **Producer and State Payments**.

- For a calendar month, a Producer will determine its monetary obligation to the State, or the State's monetary obligation to the Producer or its affiliates. The Producer's monetary obligations to the State are the sum of the payments due under Articles 11.2, 11.4, 12, 13, 14, 15, 17, and 19, as well as payments due to the State as an award under the Contract and any reimbursements owed to the State under Article 22.3.

- The State's monetary obligations to the Producer are the sum of the payments due under Articles 8.3, 10.11, 11.4, 20, 21.3, and 22.1(g), as well as (i) payments due to the Producer as an award under the Contract, (ii) any reimbursements to the Producer under Articles 11 or 22.3, (iii) any State monetary obligations carried over from a previous month, and (iv) credits for any monetary Political Subdivision payments by the Producer made to a Political Subdivision to fulfill an obligation to the State under Article 21.

- For any monetary obligation owed by the State to the Producer, the State may make a direct payment in a manner consistent with the accounting procedures in Exhibit A.

- The net monetary obligation for that month equals (i) the sum of all monetary obligations owed by the Producer and any direct payments made by the State, less (ii) all monetary obligations owed by the State.

- If the net monetary obligation is greater than zero, then the Producer must pay the net amount to the State by the end of the next calendar month. If the net monetary obligation is less than zero, then the State owes the absolute value of that amount to the Producer. The Producer will invoice the State for the amount owed by the State, and the State may pay the amount in a manner consistent with the accounting procedures in Exhibit A.

- Failure to Fully Pay. If the State fails to pay the full amount of any State net monetary obligation, the Producer may apply interest to the net obligation and do any of the following:

  (i) carry the amount due forward and recoup or offset it in the next month;

  (ii) exercise a right of Sales Recoupment or Gas Recoupment (described below);

  (iii) transfer the right to recoup or offset the amount due to a transferee;

  (iv) give notice to the State that its obligations to the State for the following 3 months will be insufficient to allow it to recoup or offset the amount due, in which case the State must notify the legislature of the amount due so that an appropriation for payment can be made; or

(v) give notice to the State to recoup or offset the amount due as either a Sales Recoupment or a Gas Recoupment, if a State monetary obligation is due and remains unpaid for 3 months.

- Sales or Gas Recoupment. If a State monetary obligation remains unpaid one month after the Producer provided notice of its intent to recoup or offset the amount due, the Producer may exercise Sales Recoupment or Gas Recoupment on Tax Gas and Available Royalty Gas to recoup that unpaid State monetary obligation. If a Producer exercises Sales Recoupment, it may receive up to 50% of any payments under State Gas sales contracts for Tax Gas and Available Royalty Gas. If a Producer exercises Gas Recoupment, it may reduce up to 50% of the volume or quantity of Tax Gas and Available Royalty Gas that the Producer would otherwise have to deliver to the State.

- Limit to Sales or Gas Recoupment. The Producer's right to Sales Recoupment or Gas Recoupment greater than the 50% described immediately above is subordinate to any liens, security interests, or rights to repayment granted by the State or the State Capacity Holder, as applicable, if and to the extent that:

  (i) it has incurred indebtedness to make a firm transportation commitment to meet the credit standards established in the initial Open Season or to otherwise finance the start-up of the State Capacity Holder, including the funding of reserves necessary to establish its creditworthiness; and

  (ii) it could not have met the firm transportation commitment and required credit standards or, in the case of the State Capacity Holder, to otherwise finance its creation without incurring that indebtedness.

- Recoupment Sequence. If the Producer chooses to recoup or offset, then it must do so in the following order:

  (i) The Producer is entitled to Sales Recoupment effective the first month after giving notice to the State, and the State must direct its customers under a State gas sales contract to pay part or all of the proceeds to the Producer to recoup or offset the amount due.

  (ii) If the Producer does not receive payment in full from Sales Recoupment by the end of the first month after giving notice to the State, then it may reduce the volume of Tax Gas that it would otherwise deliver to the State, in which case the Producer shall:

    (a) acquire from the State, at the Effective Rate, the Capacity necessary to transport that Gas Recoupment volume; and may

(b) acquire an assignment of part or all of the State Gas sales contracts sufficient to sell a Gas Recoupment volume.

The State shall indemnify the Producer against any Loss resulting from the Producer's performance under items (a) and (b) above, except in the case of gross negligence, willful misconduct or fraud.

(iii) If the Producer still has not fully recouped or offset the amount due, then the Producer may reduce up to the full volume of Available Royalty Gas that it would otherwise deliver to the State, in which case the Producer shall:

(a) acquire from the State, at the Effective Rate, the Capacity necessary to transport that Gas Recoupment volume; and may

(b) acquire an assignment of part or all of the State Gas sales contracts sufficient to sell a Gas Recoupment volume.

The State shall indemnify the Producer against any Loss resulting from the Producer's performance under items (a) and (b) above, except in the case of gross negligence, willful misconduct or fraud.

- The Producers do not have a right to reduce the volume of Royalty Gas dedicated to the Permanent Fund.
- The calculations of Gas Recoupment volume and Gas Recoupment value are described in Article 22.1(h) and 22.1(i), and example calculations are provided in Exhibit F.
- Before beginning or ending Gas Recoupment, the Producer must give notice to the State, and the State must cooperate with the Producer by providing appropriate information to effect the Gas Recoupment.

2. **Midstream Entity and State Payments**.

- For a calendar month, a Midstream Entity will determine its monetary obligation to the State, or the State's monetary obligation to the Midstream Entity. The Midstream Entity's monetary obligations to the State consist of the sum of the payments due under Articles 11.2, 11.4, 16 and 19, as well as payments due to the State as an award under the Contract and any reimbursements to the State under Article 22.3. The State's monetary obligations to the Midstream Entity consist of the sum of the payments due under Articles 8.3, 11.4, 21.3, as well as (i) payments due to the Midstream Entity as an award under the Contract, (ii) any reimbursements to the Midstream Entity under Articles 11 or 22.3, (iii) any State monetary obligations carried over from a previous month, and (iv) credit for any monetary Political Subdivision payments made by the Midstream Entity to a Political Subdivision to fulfill an obligation to the State under Article 21.

- For any monetary obligation owed by the State to the Midstream Entity, the State may make a direct payment in a manner consistent with the accounting procedures in Exhibit A.

- The net monetary obligation for that month equals (i) the sum of all monetary obligations owed by the Midstream Entity and any direct payments made by the State, less (ii) all monetary obligations owed by the State.

- If the net monetary obligation is greater than zero, then the Midstream Entity must pay the net amount to the State by the end of the next calendar month. If the net monetary obligation is less than zero, then the State owes the absolute value of that amount to the Midstream Entity.

- Failure to Fully Pay. If the State fails to pay the full amount of any State net monetary obligation, the Midstream Entity may apply Interest to the net obligation and do any of the following:

  (i) carry the amount due forward and recoup or offset it in the next month;

  (ii) recoup or offset the amount due, if not incorporated in its rate, against distributions due the State member of the Midstream Entity, provided that this right is subordinate to:

    (a) the payment of all amounts due on debt incurred to finance the State's equity interest in the Project; and

    (b) any security interest or lien granted to a lender to secure that debt.

  (iii) transfer the right to recoup or offset the amount due to a transferee; or

  (iv) give notice to the State that its obligations to the State for the following 3 months will be insufficient to allow it to recoup or offset the amount due, in which case the State must notify the legislature to authorize and appropriate moneys for payment to the Midstream Entity.

3. **Overpayment**. If a Participant or its affiliate makes an overpayment the State shall reimburse that Participant (except as otherwise provided in Article 11). If the State makes an overpayment, the Participant likewise shall reimburse the State.

4. **Reporting and Payment Procedures**. The Parties shall provide reports, maintain books and records, and make payments pursuant to Article 22 and Exhibit A.

ARTICLE 23: POINT THOMSON

1. **PTU Owner Obligations**. Each Producer's share of PTU Gas (under ownership as of the Effective Date of the Contract) is as follows:

    (i) BP: 128 million cubic feet per day

    (ii) ConocoPhillips: 20 million cubic feet per day

    (iii) ExxonMobil: 148 million cubic feet per day

- Each Producer shall commit its share of no less than 500 million cubic feet per day of PTU Gas to the Project by either entering into (i) a binding precedent agreement in the initial Open Season for the Mainline, or (ii) a sale of Gas to a non- affiliated Person before the initial Open Season for the Mainline.

- The Producers must apply to the Alaska Oil and Gas Conservation Commission for issuance of pool rules to authorize the field Gas offtake rate.

2. **Temporary Suspension of Certain Obligations**.

- Subject to Article 23.3 (see Item 3 below), from the Effective Date of the Contract until the date of initial delivery of PTU Gas into a Midstream Element (excluding line pack), the DNR will not:

    (i) enforce the Expansion Agreement;

    (ii) terminate the PTU or any Property within it;

    (iii) enforce any obligation that the PTU owners prepare and obtain approval of a plan of development from the DNR; or

    (iv) alter or modify the rate of development or operations for the PTU.

3. **Termination of Suspension of Obligations**.

- The State may, upon 30 days notice, terminate the period of its suspension of PTU obligations before the date of initial delivery of PTU Gas into a Midstream Element if:

    (i) the PTU owners or operators fail to pay annual lease rentals after receiving notice and after a 30 days cure period;

    (ii) the Producers fail to satisfy their obligation to commit their share of PTU Gas;

    (iii) the Contract is terminated under Article 5.5 (for Participants' failure to act with the required Diligence); or

(iv) the Contract otherwise terminates.

- If the State terminates the PTU obligation suspension period then, in order to retain the expansion leases described in the Expansion Agreement, the PTU owners must:

  (i) begin development drilling in the PTU within one year after the termination of the suspension period;

  (ii) drill seven development wells in the PTU within 3 years after the termination of the suspension period; and

  (iii) submit a plan of development.

- If the State does not terminate the suspension period before the before the date of initial delivery of PTU Gas into a Midstream Element, then on that date:

  (i) the PTU owners will be excused from their outstanding obligations under the Expansion Agreement; and

  (ii) the suspension period will automatically terminate and the PTU owners shall submit a plan of development.

4. **<u>Obligation to Submit a Plan of Development</u>**.

- The PTU owners must submit a plan of development either before or on the date of initial delivery of PTU Gas into a Midstream Element or termination of the suspension period, whichever is first, except:

  (i) the PTU owners may submit the plan of development within 9 months of the date of initial delivery of PTU Gas into a Midstream Element or termination of the suspension period; and

  (ii) during that 9 month period, the State shall not terminate the Point Thomson Unit Agreement or any other property within the PTU.

ARTICLE 24: MEASUREMENT

1. **Equality of Measurements**. The measurements used by the Producers to account among themselves must be the same as the measurements used to account between the Participants and the State.

2. **Source of Measurements**. For monetary payments or deliveries of Gas based on either a volume or a quantity, a Party shall use the measurements provided by either the Project Entity owning the Midstream Element or the other Person responsible for making those measurements. For payments based on barrels of Hydrocarbon Liquids, a Party shall use measurements provided by the Person responsible for making those measurements.

3. **Composition of Gas and Hydrocarbon Liquids**. Gas that is delivered to the State at each Delivery Point must be of the same composition as Gas delivered to the Producers at that Delivery Point. Hydrocarbon Liquids delivered to the State at each Delivery Point must be of the same composition as Hydrocarbon Liquids delivered to the Producers at that Delivery Point.

4. **Alternative Arrangements**. The Parties affected by Article 24 may create procedures or other arrangements to ensure that measurements of volumes, quantities, compositions of gas and barrels of Hydrocarbon Liquids are accurately and consistently undertaken.

5. **Adjustments**. If a Participant's Royalty Gas or Tax Gas obligations must be adjusted because of a change in a measurement, the adjustment must be made prospectively in proportion to that Participant's share of Royalty-Bearing or Tax-Bearing Gas, without any monetary compensation. However, if two or more Producers make a monetary adjustment or payment among themselves as a result of a measurement adjustment, a proportionate monetary adjustment must also be made between the affected Producers and the State.

ARTICLE 25: AUDIT

1. **Scope of Audit**: The scope of an audit is limited to the audit documents that are necessary to verify the satisfaction of a Participant's Fiscal Obligations. The State shall complete each audit and issue a final written audit report containing all audit exceptions related to the calendar year(s) or SCIT calendar year(s) audited, and information sufficient to support each Audit Exception.

2. **Audit Period**: The audit period in which the State shall complete all audits and issue its audit report is:

   - 3 years from the return due date, extended return date, or the date the initial or amended return was filed (whichever occurs last) for an audit under Article 19 (Payments in Lieu of State Corporate Income Tax).

   - 3 years after the end of the calendar year in which the report being audited was filed for audits under Articles 12-17, 20, and 24 (regarding Royalty Payments, Tax Bearing Gas Payments, Payments in Lieu of Production taxes, Upstream Facilities Payments, Midstream Payments, Payments in Lieu of Oil Pipeline Ad Valorem taxes, cost allowances, and measurements).

   - 2 years after the end of the calendar year in which the report or invoice being audited was filed for all other Articles in the Contract.

   - For items under any article other than Article 19 that are amended by subsequent returns, reports, or invoices, the amended audit period is 2 years from the day the amendment is filed.

   - The State and the Participant may extend the audit period only by written agreement.

3. **Special Provisions for Audits of Payments in Lieu of SCIT**: Any audit by the State of a Payment in Lieu of SCIT will be conducted under Article 25 and the procedures in Exhibit B, plus the following additional provisions:

   - State Audits: The audit of payment in lieu of SCIT is governed by Article 25 despite any provision relating to audit in the text of Alaska Statute 43.20.

   - Federal Adjustments: If a Participant or the federal government makes an adjustment to a reported federal income tax that modifies the amount the Participant should have paid as its Payment in Lieu of SCIT for a prior year and that adjustment becomes final, then the Participant must file an amended consolidated return for the applicable year. A federal adjustment becomes final when either the Participant or the federal government has exhausted its rights of appeal under federal law.

- Amended Payment in Lieu of SCIT: After any federal adjustment becomes final, the Participant must ensure that the audit documents necessary to support the changes to the calculation of any amended payment in lieu of SCIT are maintained and made available to the State upon request. The State may audit the amended consolidated report for only those items that were affected by the federal adjustment.

- IRS Tax Information: If the IRS indicates that it will no longer provide information because it believes that the State is not enforcing a tax, then the Parties agree to create an alternative procedure for providing and verifying audit documents on a timely basis.

- No State Audit of Federal Items: Certain items of income and expense that are subject to audit by the IRS are not subject to audit by the State absent a showing of good cause. The federal items not subject to State audit are listed in Article 25.3(d).

- No State Audit of Foreign Counterparts to Non-Auditable Federal Items: Absent a showing of good cause, the State may not audit the amount of any item of foreign financial statement income that corresponds to or is the counterpart of any non-auditable federal item described in Article 25.3(d).

ARTICLE 26: MANDATORY DISPUTE RESOLUTION

1. **Exclusive Remedy**. All disputes under the Contract will be resolved by the amicable resolution and arbitration procedures specified in Exhibit C, except disputes to judicially enforce or vacate any award, order, or judgment rendered under the mandatory dispute resolution procedures.

2. **Forum and Jurisdiction**. Any defense based on immunity under Article 26 and the mandatory dispute resolution procedures is waived.

   - An award rendered under the mandatory dispute resolution procedures is final and may be entered and enforced in any Superior Court in Alaska.
   - If a Party to the dispute seeks entry and enforcement of an award in Superior Court and the Superior Court does not enter a final judgment within 365 days from the commencement of the proceeding, the award may be enforced in any state court in the U.S. having jurisdiction.
   - For the purposes of enforcing an award, the Parties consent to be sued in the courts in their own name, and in the name of their officials in their official capacities.

3. **Governing Law**. Except as provided in Exhibit C, the laws of the State of Alaska (except its conflict of laws principles) will govern any dispute that is submitted to arbitration or a court.

4. **Termination and Withdrawal**. Article 26 and the mandatory dispute resolution procedures contained in Exhibit C will survive the termination of the Contract or a withdrawal by any Participant.

ARTICLE 27: JUDICIAL CHALLENGE AND ORDER

1. **Judicial Challenge**. The State shall not initiate any action or proceeding challenging the constitutionality, validity, legality and enforceability of any part of the Contract, the SGDA or the Authorization Act ("Judicial Challenge"). In the event of a Judicial Challenge:

    - The Parties shall defend against the challenge and shall support each part of the Contract, the SGDA and the Authorization Act as well as support the right of each other Party to intervene in the defense.
    - If a Judicial Challenge occurs before Commencement of Commercial Operations, the Mainline Entity may suspend any of its obligations if it provides a notice ("Judicial Suspension Notice") to the State and Participants before entry of a final non-appealable judicial order.
    - If the Mainline Entity provides a Judicial Suspension Notice, then any other Participant may suspend its obligations by providing a Judicial Suspension Notice to the State and the other Participants.

2. **Suspension Details**.

    - The Judicial Suspension Notice remains in effect until terminated by notice to the State or 90 days after date of entry of the order, whichever is earlier.
    - While the Mainline Entity Judicial Suspension Notice is in effect, each Mainline Entity or Judicially impacted Participant obligation listed in the suspension notice is suspended, except for payments required under Articles [14], 15, [17], and 19.
    - Each Party bears its own costs for suspensions under Article 27, but no penalty or Interest accrues on amounts that otherwise would be payable by Mainline Entity and Judicially impacted Participants to the State.
    - After the termination of the Mainline Entity Judicial Suspension Notice, the time for performance of all obligations identified in each Judicial Suspension Notice is extended by the number of days the suspension was in effect.
    - The Mainline Entity may amend its Judicial Suspension Notice. However, the effective date remains the same as the original suspension notice.

3. **Limits on Suspension**. The Mainline Entity and Judicially Impacted Partnerships may not exercise judicial suspension rights until the earlier of (i) 15 months from the Effective Date, (ii) the conclusion of Project planning, or (iii) the Project Entities have cumulatively spent $120 million to advance Project planning.

4. **State Option**. The State may elect to fund continued Project planning, at its sole cost and expense, if Mainline Entity has provided notice of intent to suspend, but the Participants have not completed Project planning as described in Article 5.1. This State-

funded planning may continue until (i) Project planning is concluded under Article 5.1, or (ii) the State has funded an additional $45 million.

- If the State exercises its option to fund continued Project planning, then the Mainline Entity and Judicially impacted Participants may suspend their obligations only upon (i) the completion of State-funded planning described immediately above, or (ii) the failure of the State to fund all capital contributions up to $45 million requested by a Project Entity to continue planning.

- If the Contract remains in effect after issuance of a judicial order, the Contract requires that the State be reimbursed through each Project Entity by adjusting the other members' capital contributions to that Project Entity.

5. **Judicial Order**. Any Participant may terminate participation in the Contract, by providing notice to the State within 60 days of the judicial order and will be discharged from further obligations other than those that accrued before the earlier of (i) the effective date of the Judicial Suspension Notice, or (ii) the date of entry of the order, if:

- any order holds any part of the Contract (except Article 6), the SGDA or the Authorization Act unconstitutional, invalid, illegal, or unenforceable, or

- the order leaves open for future decision any material issue related to the constitutionality, invalidity, illegality or enforceability of the above.

6. **Contract Continuance**. If all Participants do not terminate their participation, the Contract remains in effect, as amended.

ARTICLE 28: ADMINISTRATIVE TERMINATION

1. **Administrative Termination**. The Administrative Termination Period is "the period beginning on the Effective Date and ending on the day the Participants have spent a cumulative total of $125 million from the capital accounts of one or more Midstream Entities formed to plan for, build or operate any part of the Alaska Project.

2. **Initiation of Administrative Termination**. The Commissioner of Revenue may initiate administrative termination of one or more Participant's rights, privileges and obligations during the Administrative Termination Period by giving notice to all Participants ("Administrative Termination Notice"). To do so, the Commissioner must believe either that:

   - the Participants have ceased to meet Qualified Sponsor Group requirements; or

   - the affected Participant intentionally or fraudulently misrepresented material facts or circumstances upon which the Contract was made.

3. **Process Following Notice**.

   - Opportunity to Cure: The affected Participant will have 75 days from the date of the Administrative Termination Notice to cure.

   - Disputed Notice: The affected Participant may dispute the termination notice by providing a notice of dispute to the State within 75 days of receiving the Administrative Termination Notice, and the dispute will be resolved under Article 26. The Contract remains in effect until final resolution of the dispute.

   - Suspension by Participants: In the event that the Administrative Termination Notice seeks to terminate all Participants, the Mainline Entity may suspend any of its obligations by providing the State with a notice ("Administrative Suspension Notice") before entry of a final, non-appealable resolution of the dispute.

     (i) If the Mainline Entity issues an Administrative Suspension Notice, any other Participant may then suspend performance by providing an Administrative Suspension Notice.

     (ii) The Administrative Suspension Notice remains in effect until terminated by the State or 75 days after final resolution of the dispute.

   - During the Administrative Suspension Notice's pendency:

     (i) except for payments under Articles [14], 15, [17] and 19, each Mainline Entity or impacted Participant obligation is suspended;

     (ii) each Party bears its own costs incurred in connection with the suspension; and

(iii) No penalty or Interest accrues on amounts otherwise payable by the Mainline Entity or impacted Participants to the State.

- Following termination of the Mainline Entity Administrative Suspension Notice:

  (i) if the resolution of the dispute is in favor of the Participant, the time for performance of obligations in the Administrative Suspension Notice is extended by a number of days equal to the number of days the suspension was in effect; or

  (ii) if the resolution of the dispute is in favor of the State, the affected Participant's rights, privileges and obligations under the Contract terminate.

- The Mainline Entity may amend its Administrative Suspension Notice, and the amended notice has the effective date of the original notice.

- The State may not terminate the Contract under Article 28 after being provided notice of the end of the Administrative Termination Period by the Participants.

- If an affected Participant's rights, privileges and obligations are terminated, the Contract continues in effect among the remaining Parties and the affected Participant is discharged from further obligations, except as to any rights, privileges or obligations that accrued before the earlier of (i) the date of the Mainline Entity Administrative Suspension Notice, or (ii) the date of the termination of the affected Participant's rights, privileges and obligations.

ARTICLE 29: CONFIDENTIALITY

1. **Obligation to Maintain Confidentiality**. The Parties shall keep Confidential Information and related Derivative Material confidential. A receiving Party shall not disclose any Confidential Information or Derivative Material to any Person except with the providing Party's written consent or as otherwise provided in the Contract.

2. **Exceptions to the Obligation to Maintain Confidentiality**.

   - If a document contains both non-Confidential Information and Confidential Information, a party who redacts the Confidential Information from the document is not required to maintain the document as confidential.

   - Confidential Information becomes non-confidential after 10 years from the date provided to a receiving Party unless it is required to be kept confidential under State law, or the Party has given notice that continued confidentiality is necessary to protect its proprietary information or competitive position.

3. **Use of Information**. A receiving Party may use Confidential Information or Derivative Material solely to implement or fulfill its rights or obligations under the Contract. A receiving Party must also promptly notify the providing Party of any unauthorized use or disclosure and must assist in remedying the unauthorized use or disclosure. Neither receiving nor providing assistance waives any breach of Article 29.

   - An exception allows the State to disclose Confidential Information or Derivative Material to members, permanent employees, agents, and contractors of the Alaska Legislature, but the State must disclose in writing the confidential nature of the information. The receiving Party must also agree in writing to be bound by the obligations of Article 29.

4. **Return, Destruction and Release of Confidential Information**.

   - Upon termination of the Contract, the other Parties must each promptly return all Confidential Information to the providing Party, erase or destroy all Derivative Material (including electronic devices), and notify the providing Party that it has returned and/or destroyed the information and materials.

   - Upon request from a providing Party, the receiving Party must return, erase, or destroy Confidential Information or Derivative Material unless it is subject to an ongoing dispute or Audit Exception, or the receiving Party is obligated by law to retain the Confidential Information.

5. **Compelled Disclosure**. If a receiving Party is compelled to disclose any Confidential Information or Derivative Material, the Party must notice the providing Party and cooperate with the providing Party to remedy and prevent the disclosure. If the Party cannot prevent disclosure, then it must reasonably try to obtain assurance that any disclosed Confidential Information will be kept confidential, and the Party may furnish

only the portion of the Confidential Information that the Party is legally compelled or required to disclose.

6. **Notice Requirement**. If a Party requests Confidential Information from another Party, it must also notify all other Parties of its request.

7. **Confidentiality of Project Information**. Updates to Project summaries provided under Article 5.5 and advertisements for available positions under Article 6 are exempt from the Contract's confidentiality restrictions, except that a Participant may request confidential treatment of Project Information that the Participant provides to the State by identifying the information and the reasons for requesting confidential treatment.

   - If a Participant requests confidential treatment, the State must grant the request if the Participant makes an adequate showing that the Project Information:

     (i) is a trade secret or other proprietary information that the Participant treats as confidential;

     (ii) affects the Participant's competitive position; or

     (iii) has commercial value that may be significantly diminished by public disclosure.

   - The State has 14 days to determine whether the request meets the criteria for confidentiality. If the State fails to make a determination within the 14 day period, the request is deemed granted. If the State determines that the request does not meet the criteria, the State must notify the Participant of its decision and its reasons for denying the request. The Participant has 14 days after the State's decision to give a notice of dispute.

ARTICLE 30: CONTRACT ADMINISTRATION AND NOTICE

1. **Delivery Methods**. Any Party delivering notice under the Contract must give the notice in writing, and deliver it using (i) personal delivery, (ii) US mail, (iii) an established overnight courier delivery service, or (iv) facsimile, which provides written confirmation of a completed transmission. Neither e-mail nor oral communication is notice.

2. **Notice to the State**. Notices to the State must be delivered to the Commissioners of Revenue and Natural Resources and the Attorney General.

3. **Notice of New Addressees**. Any assignee or additional person must give the State and all Participants a notice containing the name and address of the person that the assignee or additional person designates to receive notice under the Contract. The State and any Participant may change its address or designee for receiving notices by providing notice to the other Parties.

4. **Effective Date of Notice**. A notice is effective only if the delivering Party has complied with the following requirements and the addressee has received the notice. A notice will be considered received if:

   (i) it is delivered using any of the approved delivery methods, then it is received upon receipt as indicated by the date on the signed receipt;

   (ii) it is sent by facsimile, then it is received upon receipt of an acknowledgement or transmission report, generated by the sending facsimile machine, that the notice was send to the addressee in its entirety;

   (iii) in the event notice is sent to more than one Participant, it is received upon the receipt of the last Participant;

   (iv) in the event the addressee refuses to accept the notice, or if it cannot be delivered because of a change in address for which no notice was given, then it is received upon the refusal or inability to deliver;

   (v) in the event notice is received after 5:00 PM on a business day, or on a day that is not a business day, then the notice is deemed received at 9:00AM on the next business day.

5. **Authorized Persons**. The only person authorized to take an action or issue a notice on a Participant's behalf is the Person designated in Article 30 to receive notices. There will be one authorized State Administrator to coordinate with DOR, DNR and other State Persons under the Contract. The office of the Governor must, within 45 days of the Contract's Effective Date, issue and maintain an administrative order designating the authorized State Administrator, who will be

   (i) the single point of contact for issuing and receiving notices;

   (ii) responsible for resolving conflicting notices from State Persons;

(iii) the only person authorized to issue a notice of dispute; and

(iv) responsible for coordination to ensure timely and non-conflicting communication regarding Article 10.

ARTICLE 31: ASSIGNMENT, ADDITION AND WITHDRAWAL

1. **Assignment of a Person**.

- A Producer can assign its rights, privileges and obligations in a Property to a qualified assignee by providing the other Parties notice with the following information: (i) identity of assignee; (ii) the rights, privileges and obligations that are assigned; and (iii) any other information the Producer deems important.

- The DNR Commissioner shall approve an assignment to a Person other than a Producer or an affiliate unless the Commissioner makes a written finding that the assignment would adversely affect the interests of the State.

- An assignment from a Producer to an affiliate or to another Producer is effective upon notice.

2. **Addition of a Person**.

- A Producer shall add any Person to the Contract owning a Midstream Element in which one or more Producers or their affiliates have an interest [or a Producer affiliate that owns an interest in an oil pipeline that will be subject to the payment in lieu of oil pipeline ad valorem taxes.]

- To do so, the Producer must provide a notice to the other Parties containing: (i) a description of the reason for adding the additional Person, (ii) identity of the additional Person, (iii) the rights, privileges and obligations assumed by the additional Person, and (iv) any other information the Producer deems appropriate.

- For an additional Person, the exemptions and covenants provided in the Contract are limited to Taxes, other than SCIT, on that portion of the Project that has been assumed by the additional Person.

3. **Conditions Regarding Assignees**.

- For assignees that are not affiliates of the assignor and additional Persons:

  (i) obligations to pay SCIT are modified only by the adjustments provided by Articles 19.3, 19.4 and 19.5; and

  (ii) the exemptions and covenants in the Contract are limited to Taxes, other than SCIT, on that portion of the assignee's oil and gas activity in Alaska that has been assigned to it.

- The above conditions do not apply (i) to assignees that are affiliates of the assignor or another Producer or its affiliate; (ii) if ownership of a Producer or affiliate is transferred by stock sale, merger, reorganization or similar transaction; and (iii) if a Producer and its affiliate sells all or substantially all of their Alaska oil and gas assets.

4. **Effect of Assignment, Addition and Transfers**.

- Each assignee and additional Person is deemed a Participant and the Contract binds and benefits both. A Person owning an interest in a Project Entity is not a Participant based solely on that interest.

- Each Producer and its affiliates retain all their rights, privileges and obligations other than those assigned or assumed.

5. **No Fee for Additional Person**. No Party may charge a fee solely because the Person is becoming an additional Party to the Contract.

6. **Acquisition**.

- If any Producer acquires or is assigned any interest in any Property listed on Exhibit D, the Producer may add its interest in that Property to Exhibit D.

- If a Producer acquires or is assigned an interest in any lease not listed on Exhibit D, the Producer may add its interest as a Property to Exhibit D subject to the following:

  (i) for leases acquired in a State lease sale, the Property must be removed from the Exhibit if Gas is not delivered to the Mainline within 15 years after its addition to the Exhibit;

  (ii) for leases acquired in a federal or private lease sale, the Property must be removed from the Exhibit if Tax Gas is not delivered to the Mainline within 20 years of its addition to the Exhibit; and

  (iii) a law of general applicability is enacted providing for a uniform upstream financial contract substantially in the form of Attachment 2 to the Contract.

- To add an interest in an ANS oil and gas lease to Exhibit D, a Producer must provide a notice to the Commissioner that includes the date Additional Property was acquired and the effective date of its addition to Exhibit D, the Producer’s Working Interest share of the Additional Property, and other information required to be included in Exhibit D.

7. **Withdrawal**.

- Before Open Season. Any Participant may withdraw from the Contract before execution by the State of the binding precedent agreements associated with the initial Open Season to reserve transportation Capacity.

- After Open Season. Any Participant may withdraw after execution by the State of those precedent agreements, provided that it and its affiliates have either assigned or relinquished and hold no direct or indirect interest in any Midstream Element or in any Property before providing the notice of withdrawal.

- A Participant wishing to withdraw under Article 31 must provide 60 days notice to the State and other Participants, and the withdrawal is effective at the end of the 60 days.

- Upon the effective date of withdrawal, the Participant only has the rights, privileges and obligations that accrued before that effective date. Subsequently, the withdrawn Participant is entitled to notice of any dispute arising out of or relating to the Contact if it has the potential to impact the withdrawn Participant's interests.

- After a Participant's withdrawal, the Contract continues in effect among the remaining Parties.

ARTICLE 32: NO JOINT MARKETING

The Contract does not provide for any joint marketing by the Parties of Gas, NGLs, or any other substances. Nor does the Contract authorize any actions prohibited by antitrust laws, and it does not limit either the State's or any Participant's ability to sell its Gas to anyone.

ARTICLE 33: NO THIRD PARTY BENEFICIARIES

Only the Parties to the Contract and their affiliates have rights under the Contract. No one other than the Parties or their affiliates may commence any dispute resolution proceeding, judicial action, or regulatory proceeding regarding the Contract.

ARTICLE 34: NO AGENCY

No Party will be considered an employee, agent, representative or partner of any other Party under the Contract.

ARTICLE 35: FORCE MAJEURE

1. **Definitions**. "Force Majeure" is a Force Majeure Event that causes a Party to be unable to perform an obligation, or materially adversely affects either the Party's performance of an obligation or its ability to satisfy the Diligence standard set forth in Article 5. A "Force Majeure Event" is an event, whether foreseen or not, that is beyond the reasonable control of a Party and includes:

   - 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;
   - Laws of federal, state, Canadian or other governmental entities, or unreasonable delays or failures to act by such entities.

2. **Notice**. If a Force Majeure occurs, an affected Party must provide prompt notice to the other Parties, including its effective date and likely duration. Likewise, when the Force Majeure has ended, the Affected Party must promptly provide notice, with specification of the duration and impact of the Force Majeure and a summary of relief sought by the affected Party.

3. **Party Actions**. No Party may act with the intent of causing a Force Majeure Event. Laws or written directives of the State, Political Subdivisions or other governmental authority within Alaska that affect the State's performance of its Contract obligations may not be invoked by the State as a Force Majeure.

4. **Suspension Rights**. During a Force Majeure, an affected Party's obligations under the Contract are suspended, except that the Affected Party may not exercise its suspension rights until the earlier of (i) 15 months from the Effective Date of the Contract, (ii) the conclusion of Project planning, or (iii) a total of $120 million has been spent to advance Project planning.

5. **Mitigation**. The affected Party must act with reasonable diligence to mitigate a Force Majeure and avoid delay or suspension of work to be performed under the Contract. Reasonable diligence does not require a Party to enter into an agreement, pay any sum to, or settle a dispute with a labor union or entity, or native or aboriginal group or entity.

6. **Interest**. No penalty or Interest accrues on amounts that would have otherwise been payable but for a Force Majeure.

7. **Time Periods**. After recovery from a Force Majeure, the Parties have an extension of time to complete their obligations equal to the number of days that the Force Majeure existed.

ARTICLE 36: INFLATION ADJUSTMENT AND INTEREST

1. **Inflation Methods**. Many of the rates and payment amounts in the Contract will be adjusted for inflation:

    - The rates for the Midstream Payment, UCA, and Fiscal Stability Cap will be adjusted annually for changes in the CPI. The rates will be multiplied by a ratio of the CPI for the new calendar year to the CPI for calendar year 2005.

    - The rates for the Upstream Facilities Gas Payment will be adjusted annually at 80% of the annual change in the CPI.

    - The rates for the Upstream Facilities Oil Payment will be adjusted annually at 70% of the annual change in the CPI beginning in 2007.

    - Certain Impact Payments specified in Article 18 will also be adjusted if the payment extends beyond 9 years from the Effective Date. If so, the payment amount in Article 18.1 will be multiplied by the ratio of the CPI for the new calendar year to the CPI for the calendar year 9 years from the end of the year in which the Effective Date occurs.

    - The CPI for a particular calendar year is the CPI for the month of December of the prior calendar year. For example, the CPI for 2008 would the CPI for December 2007.

2. **Interest Amounts**. Interest on any unpaid payment obligation under the Contract will accrue starting on the first business day after the day when the payment is due.

    - The interest rate on unpaid obligations equals two percentage points plus the interest compounded monthly at the per annum rate for the one-month term at LIBOR, which is published daily in the Wall Street Journal or the Financial Times of London.

    - The applicable LIBOR will be the rate published on the first business day immediately before the payment due date. Thereafter, the applicable LIBOR will be the rate published on the first business day of each succeeding calendar month.

ARTICLE 37: LIABILITY AND LIMITATION ON DAMAGES

1. **Liability**. Each Party is liable for its own acts and omissions and any breach of its obligations under the Contract and the liabilities and obligations of each Participant are individual, not joint and several.

2. **Damages and Remedies Limitation**. The State and the Participants have agreed to limit the recovery of certain types of Losses:

   - No Party will be liable to any other party for any consequential or incidental damages, including lost profits, or any special or punitive damages that arise or relate to the Contract or any breach of the Contract.

   - No Party may claim or collect (if awarded) any prohibited Loss from any other Party in any proceeding arising out of or relating to the Contract or any breach of the Contract.

   - The Tribunal shall enforce, but not amend (except for correction of minor clerical errors), the terms of the Contract.

3. **Indemnification Limitation**. If there are insufficient amounts available to recoup or offset an amount due from the State to a Participant, the Participant may request that the State pay the deficiency through an appropriation of State funds.

   - This provision is subject to the limitations on consequential, incidental, special, and punitive damages under Article 37.2.

   - The Participant must give notice to the State of such a deficiency, and the State shall request an appropriation of funds from the Legislature to pay the deficiency. The Legislature's failure to make such an appropriation does not create a dispute under the Contract; however, the underlying obligation will remain and is not extinguished.

   - Until the deficiency amount is appropriated by the Legislature and paid to the Participant by the State, the Participant may continue to recoup or offset against the deficiency until the deficiency is satisfied.

4. **Termination Limitation**. The State is not entitled to terminate the Contract except as provided in Article 5 and Article 28.

ARTICLE 38: INTERPRETATION PROVISIONS

1. **Contract Interpretation**. The Contract constitutes the final, entire, and exclusive agreement among the Parties on the subject matters contained in the Contract. All prior draft agreements, notes, understandings, or negotiations of the parties are superseded by the Contract. However, the provisions of the Contract may be explained, supplemented or qualified through evidence of a course of conduct between the State and the Participants after the Effective Date, but not by parole evidence.

2. **Waiver**. The only way that a Party may consent to or waive a breach of the Contract or a default by another Party is by giving notice. However, giving notice does not operate as either a consent or a waiver of any future default by the same Party.

3. **Presumptions**. In the interpretation of the Contract, no doctrine or principle of law or equity will apply if the doctrine or principle would create a presumption for or against the position of any Party to the Contract, except as provided in Article 19.9.

4. **Reliance**. Except for the statements, representations, warranties and agreements provided for in the Contract, no Party can rely on any other statement, representation, warranty or agreement of any other Party.

5. **Construction**. Because the Contract is the product of the Parties' joint efforts, it will not be construed against any particular Party as the drafter.

6. **Contract Headings**. The headings throughout the Contract are for reference purposes only and do not affect its interpretation.

7. **Retroactive Amendments**. If a State statute or regulation as it read as of a particular reference date is incorporated by reference as part of the Contract, any amendment to that statute or regulation that is retroactive to a date before the reference date will be disregarded for purposes of interpreting the Contract.

ARTICLE 39: PARTS OF THIS CONTRACT

1. **Amendments**. The Parties may amend the Contract only by a written instrument that is signed by all of the affected Parties and with a notice to all the Parties that includes the signed written instrument.

2. **Counterparts**. The signatures of all Parties need not appear on the same counterpart of the Contract, but the Contract is not binding until all of the Parties have executed a counterpart.

3. **Exhibits**. All of the Exhibits to the Contract are part of the Contract. If text within the body of the Contract conflicts with text in the Exhibits, the body of the Contract will control.

4. **Attachments**. Unlike Exhibits, Attachments to the Contract are for reference purposes only and are not considered part of the Contract.

ARTICLE 40: REPRESENTATIONS AND WARRANTIES

1. **State Representations**. The State represents and warrants that it has the requisite power and authority under the law to execute and deliver the Contract.

2. **Participant Representation**. Each Participant in the Contract represents and warrants that it has the power and authority to execute and deliver the Contract.

3. **Authority**. Each Party represents and warrants that its signatory on the Contract has been authorized by all necessary corporate or State action to execute and deliver the Contract.

4. **Judicial Challenge**. Nothing in Article 40 makes a Party liable to any other Party if the Alaska Supreme Court determines that the Contract does not comply with State law.

ARTICLE 41: RELATIONSHIP TO LAW AND OTHER AGREEMENTS

1. **Sovereign Power and State Law**.

- The Parties agree that the Contract, coupled with the enactment of changes to the SGDA and other legislation is consistent with State law.
- The State's equity participation in any Project Entity does not restrict the State's sovereign power to regulate the Project under applicable law, e.g., enforcement of environmental laws and regulations.

2. **Relationship to Other Documents**.

- If there is a dispute regarding whether the Contract and another document create conflicting rights, privileges, or obligations, the Parties will first attempt to resolve the dispute in good faith by attempting to harmonize them. If the Parties cannot harmonize them, the Contract will control.
- After the Effective Date of the Contract, any right, privilege, or obligation of a Party in a lease, agreement, other regulation, rule, order, or decision will be amended for the term of the Contract to the extent that it is necessary to conform to the provisions in the Contract.

ACKNOWLEDGEMENT

The Contract will not be effective until (i) the necessary legislation is enacted, (ii) the Legislature authorizes the Governor to execute the Contract, and (iii) the Governor and all other Parties subsequently execute the Contract.

LIST OF EXHIBITS

LIST OF ATTACHMENTS

Appendix F

Finance Plan Report

FINANCE PLAN REPORT

MAY 8, 2006

PREPARED BY:

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TABLES AND DIAGRAMS

Executive Summary

This executive summary highlights the most salient aspects of this Finance Plan Report. This report has been prepared at the request of the Alaska Department of Revenue (the "Department of Revenue") by Challenger Capital Group Ltd., Credit Suisse and UBS Investment Bank in their capacity as financial advisors to the State of Alaska (the "Financial Advisors") in connection with the proposed construction, development and financing of a natural gas pipeline and related facilities to transport natural gas from the Alaska North Slope ("ANS") to markets in Alaska, Canada and the contiguous states of the United States of America (the "Project"). A "Glossary of Defined Terms" is included at the end of this report.

Introduction

This report presents an analysis of the key issues relating to the financing of the Project and the role of the State of Alaska (the "State"), as a 20% equity investor in the Project (through Alaska Natural Pipeline Corporation ("PipeCo")), so as to advise the State regarding its development of a financing plan for the costs of constructing the Project (the "Finance Plan"). Broadly, the Finance Plan will consist of two components (the details of which are the focus of this report): debt financing and equity contributions. Debt financing will be incurred by either (a) Alaska Gas Pipeline Company, LLC ("Alaska LLC") (the joint venture entity, to be owned 20% by the State through PipeCo, and 80% by ExxonMobil, BP and ConocoPhillips (collectively, the "Producers") through their respective subsidiaries (collectively, the "Producer Subs"), that will develop the Alaska portion of the Project)[i] to pay the majority of Project costs or (b) (x) PipeCo[ii] to pay the majority of PipeCo's share of Project costs and (y) (possibly) the Producer Subs to pay the majority of each such subsidiary's share of Project costs. In either debt financing scenario, the State and the Producers (through PipeCo and the Producer Subs, respectively) will make equity contributions to Alaska LLC that will cover the remainder of Project costs after taking into account the debt financing. Though the financing of the Project is still several years away and there are many unresolved issues regarding Project costs and the market and regulatory conditions that will exist at the time of the financing, this report presents a variety of options that may be available to the State for financing the Project and provides a recommendation to the State for the selection of a base case Finance Plan.

The financing options available to the State are discussed more fully in the Executive Summary under the heading "Funding Fundamentals and Financing Options" and in Section 2 of this report. Based on information currently available, the Financial Advisors recommend that the State pursue a limited recourse debt financing by Alaska LLC for the majority of Project costs and that the State and the Producers pay for the remaining portion of Project costs with equity contributions to Alaska LLC. The benefits of undertaking debt financing on a limited recourse basis with Alaska LLC acting as the borrower include the following: (i) the State's liability to

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[i] For clarity of presentation, this report focuses on Alaska LLC as if it were the sole vehicle through which the Project is to be implemented, but the overall Project implementation (including both debt and equity financing of Project costs) may be spread among a number of Project entities. In any case, such Project implementation will be coordinated by the Producers and the State.

[ii] As more fully discussed below, a PipeCo debt financing would only be with respect to the State's share of Project costs.

the Project lenders under any completion support provided would be contingent and limited to the construction period; (ii) such a structure would allow for up to 80% of the total Project costs to be financed with debt; and (iii) such a financing would allow the Project to benefit from the Federal Guarantee Instruments (the "DOE Guarantees") provided by the U.S. Department of Energy (the "Department of Energy") under the Alaska Natural Gas Pipeline Act ("ANGPA"). With such debt financing covering up to 80% of the total Project costs, the State's required equity contribution to Alaska LLC would represent only 4% of the anticipated total Project costs (which, under the current estimate of $20 billion[iii] of total Project costs, would require an equity contribution by the State of approximately $800 million), thus reducing any potential impact on the State's borrowing capacity (and, therefore, its cost of capital and credit rating) as a result of participating in the Project.[iv]

As the Project progresses and as certain issues develop and others are resolved, the Financial Advisors will revise this report at least annually to provide the State with updated and refined advice and recommendations.

Benefits to the State from Participation in the Project

Current market conditions and the passage of ANGPA[v] and the Stranded Gas Development Act[vi] together bring Alaska closer than ever to realizing its potential to develop its ANS stranded natural gas resources. ANS contains vast reserves of natural gas resources that cannot be monetized at present because there is no transportation system for moving the natural gas to markets in Alaska and elsewhere in North America. The Project will provide such a transportation system and thus allow for the distribution and marketing of ANS natural gas

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[iii] Please note that the figure used in most sections of the Fiscal Interest Finding (defined below) for estimated Project costs is $21 billion. We have used $20 billion as the estimate of Project costs throughout this report because it is consistent with the estimate in the Producers' report (described under the heading "Project Costs and Tariffs") and because it makes for more round numbers when calculating the State's share of Project costs and Project revenues.

[iv] There are a range of options available to the State for raising funds for PipeCo's equity contribution to Alaska LLC (including issuing State-issued bonds). Please note that it is the Financial Advisors' recommendation that the State use direct appropriations in conjunction with certain debt instruments and possibly investments from the Permanent Fund in order to fund equity contributions from PipeCo to Alaska LLC.

[v] ANGPA aims to clarify and expedite the process of developing the Project. We have been advised by counsel to the State that, according to ANGPA, (i) the Department of Energy may issue Federal Guarantee Instruments in favor of holders of certificates of public convenience and necessity that have incurred debt to build the Project and (ii) Federal Energy Regulatory Commission (as defined below) (a) is authorized to accept and process an application for a new gas pipeline project under the Natural Gas Act; (b) is responsible for the environmental impact assessment process; and (c) has the power to order an expansion of the Project to satisfy competitive concerns.

[vi] We have been advised by counsel to the State that the Stranded Gas Development Act was created to help bring Alaska's natural gas resources to the market. According to counsel to the State's analysis of the Stranded Gas Development Act, the act encourages new investment to develop the State's stranded gas resources by authorizing the establishment of fiscal terms for a qualified project that relate to new investment by a qualified sponsor or the members of a qualified sponsor group. The specific fiscal terms will be tailored to the particular economic conditions of the relevant qualified project. The act also aims to maximize the benefit to the people of Alaska of the development of the State's stranded gas resources.

resources to the benefit of the State and its citizens. In addition to the many benefits from the Project related to royalties, taxes, job creation and general economic stimulation that are more fully discussed in the Preliminary Findings and Determination prepared by the Department of Revenue (the "Fiscal Interest Finding"), the State (through PipeCo), as a 20% equity investor in the Project, is projected to receive considerable annual revenues, potentially in the billions of dollars.

Project Costs and Tariffs

The Project is unique in its size, scope and cost. Detailed reports prepared jointly by the Producers and completed in 2002 estimate that the Project will cost approximately $20 billion, and may cost substantially more, and that it will take approximately three years to build the Project's various components across multiple domestic and international borders. The Project cost estimate will be revised after the engineering and design work is completed and as the Project becomes better defined.

Revenues to the State and the Producers as equity investors in the Project will be generated by tariffs that will be charged to shippers of natural gas for delivery of natural gas to an off-take point under the applicable long-term "firm delivery" shipping contracts (the "Firm Transportation Contracts"). Such tariffs will be set as part of a regulatory process by the Federal Energy Regulatory Commission ("FERC") with respect to the Alaskan portion of the Project, and by its Canadian equivalent, the National Energy Board ("NEB"), with respect to the Canadian portion of the Project. We have been informed by counsel to the State that FERC tariffs are designed broadly based on an imputed capital structure for the Project and will be set at a level that provides a certain return on equity after covering all of Alaska LLC's costs, including debt service, operating expenses, depreciation and taxes. While "open season" tariffs have not yet been set, we have been advised by counsel to the State that the State may expect that the FERC-approved tariffs (and NEB-approved tariffs, as applicable) will likely include a "reasonable" return on equity. We have been advised by the State's Canadian counsel that NEB will follow a similar rate-setting procedure.

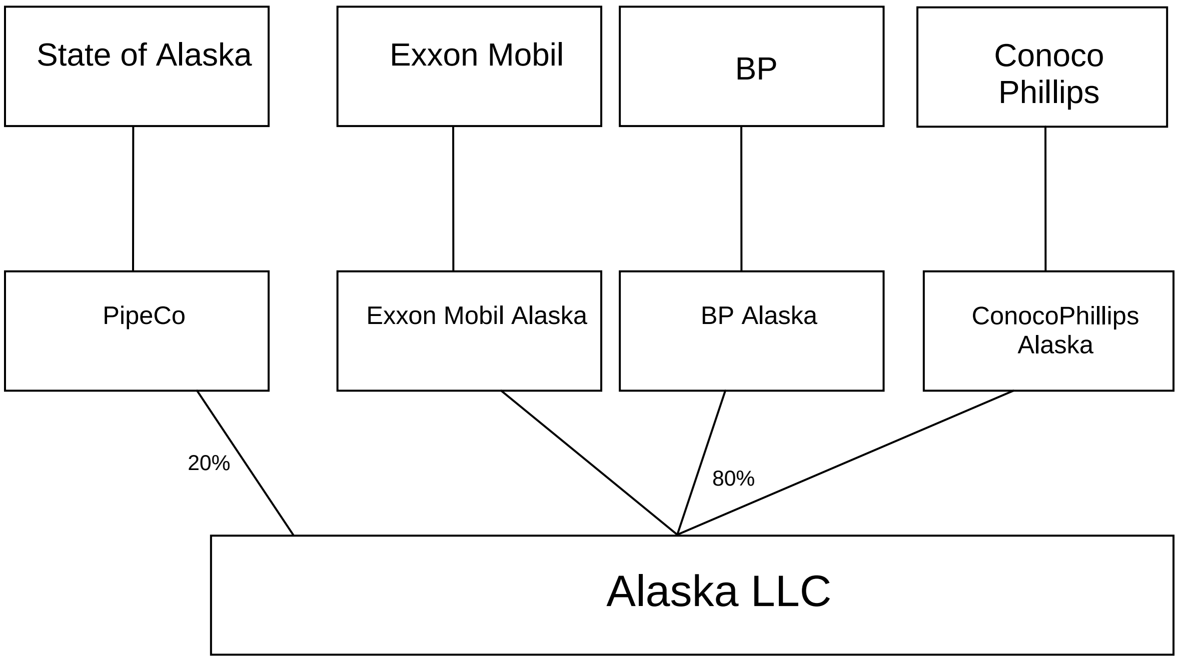
An analysis of the tariff structure is critical when considering financing options for the Project. Lenders will look to the revenue stream of the Project generated by the tariffs and the credit worthiness of the shippers responsible for paying such tariffs to determine the likelihood that loans advanced to pay the costs required to build the Project will be repaid on time. Even if completion support is provided by the Producers and/or the State to provide lenders with certainty that the pipeline will be completed, the lenders will still focus on the revenue stream generated by the tariffs when assessing Project economics.

Corporate Structure of Alaska LLC and PipeCo

The State and the Producers will undertake the Project through one or more project entities that they will form and own, including Alaska LLC, which will own the Alaska segment of the pipeline. The State expects to invest in Alaska LLC through PipeCo, which will directly own a 20% stake in Alaska LLC. The Producers expect to invest in Alaska LLC through the Producer Subs, which will collectively own the remaining 80% stake in Alaska LLC. PipeCo and the

Producer Subs are collectively known as the "Members." The basic structure of Alaska LLC is set forth in the diagram below.[vii]

Diagram ES-1
Basic Structure of Alaska LLC



The Limited Liability Company Agreement of Alaska LLC (the "LLC Agreement") will be entered into by the Members. Among other things, the LLC Agreement governs the operations of Alaska LLC and addresses matters related to budget procedures, dividend policy, cash contributions, decision making and voting by the Members, and the formulation and selection of a plan for financing the Project.

Section 5.2 of the current draft of the LLC Agreement provides for the establishment of a "Management Committee" (the "Management Committee") that will be comprised of representatives of each of the Members and will make all decisions for Alaska LLC according to the voting procedures set forth in the LLC Agreement. Article XI of the current draft of the LLC Agreement provides for the establishment of a "Finance Committee" (the "Finance Committee") that will be comprised of a representative from each of the Members and will be charged with investigating and developing the initial plan for the financing of the Project, including how best to utilize the DOE Guarantees. Once such plan is approved by the Management Committee, it will be deemed to be the "Finance Plan" for Alaska LLC (the "LLC Finance Plan"). The LLC Finance Plan will determine the form of the debt financing component of the Finance Plan and

[vii] Please note that ownership allocations among the Producer Subs have not been finalized.

will set forth the proposed sources, structure, tenor, terms, covenants, restrictions, collateral and timing for the debt financing of the Project.

The LLC Finance Plan is extremely important because the structure of the debt financing could have a significant economic impact on the State, and under the current draft of the LLC Agreement, approval of the LLC Finance Plan by the Members is a condition precedent to the commencement of Project construction.[viii]

Funding Fundamentals and Financing Options

Each of the State and the Producers is responsible for funding its share of Project costs. The State and the Producers are exploring a full range of financing structures and options at this time to raise the necessary funds to cover such costs. In evaluating the possible financing structures, the State and the Producers will select the structure that most comprehensively satisfies each of their goals. The State's finance objectives include the following (certain of which are common to the finance objectives of the Producers): (i) limit the State's liability (whether such liability results from provision of completion support or otherwise) for the funds borrowed for Project construction so as to mitigate the impact the Project will have on the State's borrowing capacity as well as any negative implications for the State's credit rating and cost of borrowing; (ii) approach the market in concert with some or all of the Producers so as to obtain the best financing terms available; (iii) utilize the DOE Guarantees (if the final terms of such DOE Guarantees negotiated with the Department of Energy are acceptable) to lower the cost of borrowing and increase the likelihood that the State and the Producers can finance 80% of estimated Project costs; and (iv) 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.[ix] While the State and the Producers have common finance objectives, they also have individual concerns (e.g., tax considerations, differing desires to use available cash on balance sheets, 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 Producers will make the final selection of a Finance Plan in light of such considerations and not until the specifics of the Project components, including design engineering, procurement and construction costs, are further developed.

In light of the State's finance objectives described above, the Financial Advisors advise the State (in conjunction with the Producers) to debt finance up to 80% of total Project costs with the proceeds of a limited recourse debt financing at the Alaska LLC level (an "LLC Financing"), with the remaining Project costs to be paid for with equity contributions by PipeCo and the Producer Subs to Alaska LLC. If the State and the Producers elect to pursue a financing strategy in which Alaska LLC would not be the borrower, but rather where each of the Members would

[viii] Please note that if no agreement is reached with respect to an LLC Finance Plan and the Members waive the approval of an LLC Finance Plan as a condition to commencement of Project construction, then PipeCo and each Producer Sub may separately finance its portion of the Project. We understand that the voting procedures with respect to this matter have not been finalized.

[ix] The State has an interest in lowering the tariff because, in addition to acting as an owner of the Project through PipeCo, it will also be a shipper (i.e., the party paying the tariff) through another to-be-formed subsidiary.

borrow directly and apply the proceeds of such borrowing to its share of the total Project costs (a "Member-level Financing"), then the Financial Advisors expect that PipeCo (and likely some, if not all, of the Producer Subs) would borrow 70-80% of its share of Project costs on a limited recourse basis[x] and fund the remaining portion of its share of Project costs with equity.

With respect to the debt component of the two financing strategies described above, limited recourse debt financing has been the financing vehicle of choice for the vast majority of significant greenfield, mid-stream oil and gas projects around the world during the past 10 years. The market's familiarity with this financing structure, in conjunction with the robust credit fundamentals associated with the Project (both in terms of its revenue stream and the financial strength and expertise of the Producers), should allow the lenders and the rating agencies to reach favorable conclusions with respect to the financial viability and success of the Project despite its enormous scope and cost.

Limited recourse debt financing has many benefits. If a limited recourse debt financing is undertaken by Alaska LLC, then one benefit is that the Members (most importantly, PipeCo) would not have to borrow nearly as much money in their own names. For instance, PipeCo's obligation to Alaska LLC would be $800 million, rather than $4 billion (and it might not have to borrow at all in order to fund Project costs). Reducing the borrowing at PipeCo is beneficial to the State for a variety of reasons, including the fact that any such borrowing could negatively impact the State's borrowing capacity and credit rating (each of which is more fully discussed in this report). Another benefit of limited recourse debt financing (which would hold true in the case of an LLC Financing or a Member-level Financing) is that, upon completion of the Project, none of the Members, the State or the Producers would have any liability to the lenders. Thus, during the operational period, the State's and the Producers' liability would be capped at the amount of their equity contributions with respect to operational risk associated with the Project.

Nonetheless, as discussed more fully in this report, a limited recourse debt financing would include some risk exposure for the State and the Producers prior to completion (often in the form of completion support). Specifically, each of the State and Producers (or other creditworthy affiliates of the borrower) would likely be required to provide credit support with respect to its portion of the debt borrowed by Alaska LLC (or, in the case of a coordinated Member-level Financing, by PipeCo and each Producer Sub, respectively and as applicable). Such completion support would be callable upon the occurrence of certain events, including, but not limited to, the failure to complete the Project by a specific date.

Delays in completion of Project construction may occur and there may be significant cost overruns. The risk of cost overruns affects the analysis of both the debt financing as well as the equity financing. Initially, any debt financing of the Project will include, in its baseline estimate of Project costs, some degree of cost overruns (typically 10%). However, it is possible that actual cost overruns could exceed such cushion.[xi] To the extent additional cost overrun facilities

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[x] Please note, there is some possibility that in a Member-level Financing (and assuming market conditions remain as they are today), PipeCo could borrow funds on a non-recourse basis. The details of such possibility are discussed further in Section 5.1.2 of this report.

[xi] Note that the Financial Advisors continue to evaluate whether cost overrun facilities should be sought up front or as needed.

are required, it is unlikely that the terms of such facilities would be as favorable with respect to the construction financing terms (e.g., the debt/equity ratio would likely be lower). A discussion of the effect of cost overruns on the State's equity contribution is found in Section 5.4 of this report.

During LLC Finance Plan negotiations among the State and the Producers, the State will be presented with a variety of options for financing the Project. While the interests of the State and the Producers are undoubtedly aligned on many levels with respect to the Project (e.g., reducing cost overruns and seeking limited recourse debt financing), the different economic positions of the State and the Producers (e.g., regarding liquidity and taxes) and certain other factors may result in divergent opinions when it comes to selecting a financing structure.

The State and the Producers may differ as to whether the Project should be financed through an LLC Financing or a Member-level Financing (each as more fully described below in Section 5.2.2 of this report). Under the present economic and regulatory circumstances, the Financial Advisors have advised the State that an LLC Financing best meets the stated finance goals of the State and provides the State with a favorable balance of risks and benefits. By contrast, the Producers may have different concerns that lead them to question whether they should engage in any debt financing at all (e.g., if they are cash-rich, the Producers may wish to contribute their entire share of Project costs as true equity). In addition, the Producers may have other considerations (such as tax optimization) that would make an LLC Financing undesirable to them. The Producers (or certain Producers) may also favor a Member-level Financing in order to minimize (or eliminate) any restrictions with respect to construction and operation of the Project that may be placed on Alaska LLC by lenders to the Project.

While considering financing options during the next several years, it is worth bearing in mind that despite the State's current preference for an LLC Financing, it is possible that certain factors could change in the years before the Management Committee votes on the LLC Finance Plan such that a Member-level Financing could be an equally attractive option for the State. As the situation evolves, the Financial Advisors will revise their analysis and provide the State with updated advice at least annually.

Other considerations that arise in connection with the financing of the Project include the following: amount, sources, timing and insurance for the State's equity contribution; the timing and strategy for approaching the markets generally; and the timing and strategy for negotiations with the Department of Energy.

DOE Guarantees

This report also includes an analysis of the mechanics and uses of the DOE Guarantees that is based on advice we have received from counsel to the State. The recently enacted ANGPA makes available up to $18 billion of DOE Guarantees. Under the DOE Guarantee program, the loans of parties utilizing the DOE Guarantees would be guaranteed with the full faith and credit of the U.S. government. As such, the market would look to the credit of the Federal government (rather than the borrower) when evaluating the Project. Such an upgrade in credit would likely lower the cost of borrowing for the borrower.[xii]

One of the reasons the Financial Advisors recommend pursuing an LLC Financing is that we have been advised that there is certainty that the project-level company (e.g., Alaska LLC) could utilize the DOE Guarantees. We have been advised that there is some uncertainty as to whether the Members could benefit directly from DOE Guarantees. Regardless of whether the DOE Guarantees are used by Alaska LLC or by the individual Members, the Financial Advisors suggest that the State and the Producers explore creative uses for the DOE Guarantees other than applying them just to the initial construction loan. For example, there may be significant value associated with using the DOE Guarantees in connection with seeking debt financing for cost overruns. Specifically, because the DOE Guarantees act as credit enhancements, their value (e.g., lowering the cost of borrowing) will be greater to the borrower when the borrower's credit is more depressed (e.g., in a cost overrun scenario).

<u>Role of the Permanent Fund</u>

The State and the Financial Advisors are currently exploring different roles the Permanent Fund could play in financing the Project. We have been advised by counsel to the State that the laws and regulations governing the Permanent Fund suggest that it may be able to act as an equity investor or a lender. According to counsel to the State, the primary restrictions on the use of the Permanent Fund are related to the expected return on a given investment. Specifically, investments using the Permanent Fund must maximize "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."[xiii] Thus, any investment in the Project must compare favorably, in terms of returns to the Permanent Fund, to alternative investments. We understand that the Permanent Fund Corporation (the body that manages the investment of the Permanent Fund) is evaluating the possibility of participating in the Project.

From the perspective of the Permanent Fund, the benefits of investing in the Project with equity are that the Project has strong fundamentals and is projected to return significant dividends to equity investors over the next several decades. Thus, such an investment would on its face appear to comply with the rules governing investment of the Permanent Fund. For the State, the benefits of selling an equity share in Alaska LLC to the Permanent Fund Corporation include the fact that, if the Permanent Fund were to participate, the State would be able to spread the risk of the burden of any construction costs, including cost overruns.

The Permanent Fund Corporation may also consider whether a loan to PipeCo (or, less likely, to Alaska LLC in an LLC Financing) meets its investment criteria. We note that, as a lender, the return on the investment of Permanent Fund would be lower, but it would have a lender's lower risk profile in return. From the State's perspective, the participation of the Permanent Fund

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[xii] Please note that ultimately the Federal government, after paying the lenders, would look to the Project or the State, as applicable, for reimbursement of any guarantee payments and related expenses it incurred in connection with a call on the guarantee by the lenders.

[xiii] Alaska Permanent Fund Corporation. (2001). An Alaskan's Guide to the Permanent Fund, page 45. Juneau, Alaska: Alaska Permanent Fund Corporation.

Corporation as a lender would help PipeCo meet cash calls for Project costs (particularly in the case of cost overruns) without diminishing its equity stake in the Project.

In any case, the Permanent Fund Corporation will make its own decisions regarding the form of any investment it may wish to make in the Project and whether such investment is permitted under its mandate.

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1. Introduction

This report provides an analysis of the key issues relating to the financing of the construction and development of a natural gas pipeline and related facilities to transport natural gas from the Alaska North Slope ("ANS") to markets in Alaska, Canada and the contiguous states of the United States of America (the "Project") and the role of the State of Alaska (the "State") as an equity investor (through Alaska Natural Gas Pipeline Corporation, a to-be formed Alaska public corporation ("PipeCo")) in Alaska Gas Pipeline Company, LLC ("Alaska LLC"), the entity that will develop the Alaska portion of the Project.[1] PipeCo will own a 20% equity interest in Alaska LLC and the remaining 80% will be owned by subsidiaries of ExxonMobil, BP and ConocoPhillips (collectively, the "Producers"). The purpose of this report is to advise the State regarding its development of a plan for financing the costs of constructing the Project (the "Finance Plan"). A "Glossary of Defined Terms" is included at the end of this report.

1.1 *Purpose of Finance Plan*

Broadly, the Finance Plan will consist of two components (the details of which are the focus of this report): (i) debt financing incurred by either Alaska LLC or by PipeCo[2] and (possibly) subsidiaries of the Producers (such subsidiaries collectively, the "Producer Subs") and (ii) equity contributions by the State and the Producers (through PipeCo and the Producer Subs, respectively) to Alaska LLC that will cover the remainder of Project costs after taking into account the debt financing. Though the financing of the Project is still several years away and there are many unresolved issues regarding Project costs and the market and regulatory conditions that will exist at the time of the financing, this report presents a variety of options that may be available to the State for financing the Project and provides a recommendation to the State for the selection of a base case Finance Plan.

The Alaska Department of Revenue (the "Department of Revenue") is responsible for the financing of most State projects and will be responsible for negotiating the financing of the State's share of the Project costs. The Department of Revenue has been working with the Producers to develop an overall financing plan for the Project. The Department of Revenue has retained Challenger Capital Group Ltd., Credit Suisse and UBS Investment Bank (collectively, the "Financial Advisors") to assist the State in its analysis of the Project and the possible methods of funding the State's financial obligations with respect to the Project. The State has also received advice from Government Finance Associates, the State's financial advisor since 1984. The Financial Advisors have expertise in pipeline economics, regulatory matters and project, government and corporate finance. They have been advising the State with respect to

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[1] For clarity of presentation, this report focuses on Alaska LLC 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. In any case, such Project implementation will be coordinated by the Producers and the State.

[2] As more fully discussed below, a PipeCo debt financing would only be with respect to the State's share of Project costs.

both the overall financing plan for the Project and the financing plan for the State's expected equity contribution to the Project of approximately $800 million.[3]

Based on information currently available, the Financial Advisors' recommended Finance Plan consists of Alaska LLC pursuing a limited recourse debt financing for the majority of Project costs and the Members paying their respective proportionate shares of the remaining Project costs with equity contributions (which the Financial Advisors advise the State to fund with proceeds from a combination of direct appropriations from budget surpluses, revolving loans and long-term State-issued insured bonds).[4] The benefits of Alaska LLC undertaking a limited recourse financing include the following: (i) the State's liability to the lenders to the Project would be contingent and limited to the construction period; (ii) such structure would allow for up to 80% of the total Project costs to be financed with debt; and (iii) such financing would allow the Project to benefit from the Federal Guarantee Instruments (the "DOE Guarantees") provided by the U.S. Department of Energy (the "Department of Energy") under the Alaska Natural Gas Pipeline Act ("ANGPA"). With such debt financing covering up to 80% of the total Project costs, the State's required equity contribution would represent only 4% of total Project costs (which, under the current estimate of $20 billion of total Project costs, would equal approximately $800 million),[5] thus minimizing any impact on the State's borrowing capacity and therefore, its cost of capital and credit rating, as a result of participating in the Project.

1.2 *LLC Agreement*

As briefly noted above, the Producers and the State will undertake the Project through one or more Project entities that they will form and own (most likely through intermediate entities established by the State (e.g., PipeCo) or the Producers (e.g., the Producer Subs), as applicable), including Alaska LLC, which will own the Alaska segment of the pipeline.

The Limited Liability Company Agreement of Alaska LLC (the "LLC Agreement") will be entered into among the "Members" of Alaska LLC (i.e., the intermediate entities formed by the State and the Producers to own Alaska LLC). PipeCo and the Producer Subs are collectively known as the "Members."

Though still under negotiation, the State's counsel has advised us that, among other things, provisions of the LLC Agreement will govern the operations of Alaska LLC and will address

[3] This estimate is based on PipeCo holding a 20% equity interest in Alaska LLC, and is based on the assumptions that there will be $20 billion of total Project costs, with 80% of total Project costs being financed by the Members (with PipeCo financing 80% of its share with debt) or with debt incurred directly by Alaska LLC. Please note that the figure used in most sections of the Fiscal Interest Finding (defined below) for estimated Project costs is $21 billion. We have used $20 billion as the estimate of Project costs throughout this report because it is consistent with the estimate in the Producers' report (described in Section 3.1) and because it makes for more round numbers when calculating the State's share of Project costs and Project revenues.

[4] At this time, the Financial Advisors believe that municipal bond insurance may prove beneficial for the majority of any long-term bond financing of the State's interest in Alaska LLC.

[5] There are a range of options available to the State for raising funds for PipeCo's equity contribution to Alaska LLC (including issuing revenue bonds) which are discussed below. We understand that the State favors using direct appropriations as the means for funding such equity contributions, because it is a relatively simple process and it is less likely to impact the State's borrowing capacity, credit rating or cost of borrowing.

matters related to budget procedures, dividend policy, cash contributions, decision making and voting by the Members and, as described below, the formulation and approval of a finance plan for construction of the Project by the Members.

The current draft of Section 5.2 of the LLC Agreement provides for the establishment of a "Management Committee" (the "Management Committee"), which is composed of representatives of each of the Members, that will make all decisions for Alaska LLC according to the voting procedures set forth in the LLC Agreement. The current draft of Article XI of the LLC Agreement provides for the establishment of a "Finance Committee" (the "Finance Committee"), which will be composed of a representative from each of the Members and will be charged with investigating and developing the initial plan for the financing of the Project, including how to best utilize the DOE Guarantees. Once such a plan is approved by the Management Committee, it will be deemed to be the "Finance Plan" for Alaska LLC (the "LLC Finance Plan"). We understand that the voting procedures with respect to the selection of the LLC Finance Plan have not been finalized. The LLC Finance Plan will determine the form of the debt financing component of the Finance Plan and will set forth the proposed sources, structure, tenor, terms, covenants, restrictions, collateral and timing for the debt financing of the Project.

Each of the key provisions of the LLC Agreement mentioned above have been analyzed and negotiated concurrently with the negotiation of Article XI of the LLC Agreement and the issues related to the LLC Finance Plan. We understand that the voting mechanics with respect to certain key votes (e.g., approval and adoption of the LLC Finance Plan, commencement of Project construction ("Project Sanction"), waiver of the LLC Finance Plan as a condition to Project Sanction, and approval of Project budgets) remain under discussion by the Producers and the State. However, we also understand that if no agreement is reached with respect to an LLC Finance Plan and the Members waive the approval of an LLC Finance Plan as a condition to Project Sanction, then PipeCo and each Producer Sub may separately finance its portion of the Project.

As noted above, the current draft of the LLC Agreement does not contemplate a "base case" Finance Plan. Thus, the options available to the State and the Producers for financing the Project are essentially unlimited. Notwithstanding the foregoing, historical precedent for large oil and gas projects as well as the negotiations preceding the current draft of the LLC Agreement suggest that the financing of the Project will fall into one of two categories: (i) traditional limited recourse debt financing with Alaska LLC as the borrower (also known as "project financing"), or (ii) a limited recourse debt financing in which Alaska LLC would not be the borrower, but rather each of the Members would borrow directly and apply the proceeds of such borrowing to its share of the total Project costs (a "Member-level Financing"). As such, this report will focus on the benefits, mechanics and risks of those two categories of financing from the State's perspective and make recommendations accordingly.

Another key point in the LLC Agreement that is still being negotiated is the remedies that will be available to non-defaulting Members if a Member fails to meet a cash call. We understand that the State and the Producers have agreed in principle that if PipeCo fails to make a required cash contribution to Alaska LLC at any time after Project Sanction in respect of capital expenditures then (i) the Producer Subs would have the option to fund such shortfall (a "Member Loan"); (ii) interest (at a rate to be determined) would be assessed with respect to such Member Loan; and (iii) the State would have an extended cure period to repay the Member Loans and cure its cash contribution shortfall. After the expiration of such cure period, the Producer Subs would have the option to buy PipeCo's interest in Alaska LLC at a specified purchase price. We note that the method for determining the purchase price has yet to be finalized, but it is important that, at a minimum, such a purchase price cover PipeCo's outstanding debt (or, that, as part of any buy-out, any Producer Subs participating in such buy-out (or affiliates of any such Producer Subs that meet certain credit criteria to be determined) be required to assume PipeCo's debt and the State's completion support obligations.

The resolution of issues related to, and the approval of, the LLC Finance Plan, as well as the identification of sources for PipeCo's equity contributions, will have significant implications for the State. Selection and finalization of an LLC Finance Plan and a strategy for funding PipeCo's equity obligations are critical to the timing and success of the Project and will need to be refined in tandem with the consideration and resolution of various open issues (e.g., the LLC Agreement).

1.3 *Periodic Updates of Finance Plan Report*

Please note that the analyses and recommendations set forth in this report are subject to further refinement as the equity and financing arrangements with the Producers are finalized, the Project is further developed, and discussions with financial institutions, credit rating agencies, the Permanent Fund Corporation and the Department of Energy, among others, progress. As such, the Financial Advisors will revise this report at least annually to provide the State with updated and refined advice and recommendations.

2. Benefits to the State from Participation in the Project

2.1 *Project History*

Though discovered decades ago, vast natural gas resources in ANS have not previously yielded benefits to the State for physical, economic and regulatory reasons, among others. The clearest physical barrier to the sale of ANS gas is that no transportation system exists to move ANS gas to distant markets for sale. The construction of such a transportation system would necessarily cost billions of dollars, and historically the price of natural gas has not been sufficient to justify undertaking such a project. Given the enormous size and scope of any transportation system for ANS gas, it has always been understood that a project to develop such a system would require federal and State policy initiatives in addition to positive market conditions. Several attempts have been made during the past 35 years to create favorable regulatory frameworks for the development of such a project; however, each has failed to achieve its goals due to low gas prices.

Today, high current and projected natural gas prices and the recent passage of both ANGPA[6] at the federal level and the Stranded Gas Development Act[7] in Alaska have combined to bring Alaska closer than ever to realizing its potential to develop its ANS stranded natural gas resources. The coalescence of these positive factors has spurred the State and the Producers to pursue the construction and financing of the Project – a natural gas pipeline and related facilities that would transport billions of cubic feet per day of ANS gas to markets in the United States and Canada. The Project would thus finally allow the State and its citizens to realize the benefits of the distribution and marketing of ANS's natural gas resources.

2.2 *Estimated Revenues for State*

The development and success of the Project will generate revenues for the State in a variety of ways. This report focuses on revenues to the State resulting from its role as a 20% equity investor in the Project. In addition to these revenues, the State also stands to receive billions of dollars from the Project through royalties and taxes (including revenues from gas received as in-kind payments) and many other benefits related to job creation and general economic stimulation, each of which are more fully discussed in the Preliminary Findings and Determination and prepared by the Department of Revenue (the "Fiscal Interest Finding").

2.3 *Benefits from State Ownership Interest in Alaska LLC*

The State's role (through PipeCo) as a 20% equity investor in the Project is projected to result in billions of dollars of revenues for the State. Table 1 shows the estimated projected financial results of the Project following Project completion.[8] It is contemplated that PipeCo will be a 20% owner of the Project and thus will receive 20% of the revenue stream generated by the Project.

[6] ANGPA aims to clarify and expedite the process of developing the Project. We have been advised by counsel to the State that, according to ANGPA, (i) the Department of Energy may issue Federal Guarantee Instruments in favor of holders of certificates of public convenience and necessity that have incurred debt to build the Project and (ii) Federal Energy Regulatory Commission (as defined below) (a) is authorized to accept and process an application for a new gas pipeline project under the Natural Gas Act; (b) is responsible for the environmental impact assessment process; and (c) has the power to order an expansion of the Project to satisfy competitive concerns.

[7] We have been advised by counsel to the State that the Stranded Gas Development Act was created to help bring Alaska's natural gas resources to the market. According to the analysis of counsel to the State, the Stranded Gas Development Act, the Act encourages new investment to develop the State's stranded gas resources by authorizing the establishment of fiscal terms for a qualified project that relate to new investment by a qualified sponsor or the members of a qualified sponsor group. The specific fiscal terms will be tailored to the particular economic conditions of the relevant qualified project. The Act also aims to maximize the benefit to the people of Alaska of the development of the State's stranded gas resources.

[8] Please note that these calculations are based on the basic assumptions set forth in the model developed by the Financial Advisors and other terms and conditions of the draft Project agreements under negotiation by the State and the Producers.

Table 1
Summary Income Statement
($ in millions)

	2014	2015	2016	2017	2018	2019	2020	2030	2039
Tariff Revenues	**$2,830.0**	**$2,830.0**	**$2,830.0**	**$2,830.0**	**$2,830.0**	**$2,830.0**	**$2,830.0**	**$2,830.0**	**$2,830.0**
Operating Expenses:									
Operating Cost	$401.4	$409.4	$417.6	$426.0	$434.5	$443.2	$452.0	$551.0	$658.5
Cost Overrun Operating Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Property Tax	237.2	234.3	231.8	229.7	227.9	226.3	225.0	214.6	215.0
Cost Overrun Property Tax	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Depreciation	272.4	287.4	303.2	319.9	337.5	356.0	375.6	641.6	1,038.9
Cost Overrun Depreciation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Operating Expenses	**$911.0**	**$931.1**	**$952.6**	**$975.5**	**$999.8**	**$1,025.6**	**$1,052.6**	**$1,407.3**	**$1,912.4**
Operating Income	**$1,919.0**	**$1,898.9**	**$1,877.3**	**$1,854.4**	**$1,830.1**	**$1,804.4**	**$1,777.3**	**$1,422.7**	**$917.5**
Interest Expense	$1,061.6	$1,024.9	$991.0	$959.5	$929.9	$901.8	$874.5	$589.5	$330.0
Cost Overrun Interest Expense	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Before Taxes	**$857.3**	**$874.0**	**$886.3**	**$895.0**	**$900.3**	**$902.6**	**$902.9**	**$833.2**	**$587.5**
Income Taxes	$184.5	$395.1	$388.6	$383.2	$378.7	$374.9	$371.6	$343.3	$347.4
Cost Overrun Income Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Income	**$672.8**	**$478.8**	**$497.7**	**$511.8**	**$521.6**	**$527.6**	**$531.3**	**$489.9**	**$240.1**

The potential cash flows to the State are set forth in Table 2 below.[9]

Table 2
Summary Cash Flow Statement
($ in millions)

	2014	2015	2016	2017	2018	2019	2020	2030	2039
Funds Provided:									
Net Income	$672.8	$478.8	$497.7	$511.8	$521.6	$527.6	$531.3	$489.9	$240.1
Depreciation	272.4	287.4	303.2	319.9	337.5	356.0	375.6	641.6	1,038.9
Deferred Taxes	265.5	547.8	467.0	396.9	335.2	280.9	246.4	(145.1)	(234.9)
Debt Financing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Equity Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Funds Provided	**$1,210.8**	**$1,314.1**	**$1,267.9**	**$1,228.6**	**$1,194.3**	**$1,164.5**	**$1,153.3**	**$986.5**	**$1,044.1**
Funds Applied:									
Capital Expenditures	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Debt Retired	430.4	668.2	616.1	573.4	538.2	509.5	497.7	397.2	643.2
Total Funds Applied	**$430.4**	**$668.2**	**$616.1**	**$573.4**	**$538.2**	**$509.5**	**$497.7**	**$397.2**	**$643.2**
Total Cash Available for Distribution	**$780.4**	**$645.9**	**$651.8**	**$655.1**	**$656.1**	**$655.0**	**$655.7**	**$589.2**	**$400.9**

3. Project Costs and Tariffs

3.1 *Construction Costs*

In order to complete the Project and realize the economic benefits described above in Section 2, the Producers and the State collectively will need to spend upwards of $20 billion, a figure determined following a $125 million study completed in 2002 by the Producers to estimate the cost for Project construction (including the gas pipeline, gas treatment plant and other facilities). The ultimate cost of the Project may, however, be substantially higher than $20 billion due to inflation and unforeseen construction costs. More detailed cost estimates will be prepared prior to finalization of the LLC Finance Plan and included in future iterations of this report. Based on

[9] Please note that these calculations are based on the basic assumptions set forth in the model developed by the Financial Advisors and other terms and conditions of the draft project agreements under negotiation by the State and the Producers.

information provided in Section 7 of the Fiscal Interest Finding, Table 3 shows the expected schedule for Alaska LLC's capital outlays.[10]

Table 3
Alaska LLC Capital Outlays
($ in millions)

Year	Gross Costs	Cumulative Costs
Pre-formation Costs	$ 125	$ 125
Year 1	$ 166	$ 291
Year 2	$ 274	$ 566
Year 3	$ 370	$ 935
Year 4	$ 396	$ 1,332
Year 5	$2,992	$ 4,323
Year 6	$5,399	$ 9,722
Year 7	$5,789	$15,511
Year 8	$3,053	$18,565
Year 9	$ 870	$19,435
Year 10	$ 565	$20,000

Notwithstanding that Project costs will be incurred over a ten-year period, the State and the Producers (along with the lenders) will need to be satisfied that the estimated Project costs (which will include a 10% cushion for cost overruns) will be covered by the financing and equity commitments in place at commencement of construction (or, at the latest, by the first disbursement of the loans).

Please note that a potentially important means of reducing Project costs will be the integration of the Project with existing infrastructure. To the extent the Project can "piggyback" on existing infrastructure both in Alaska and Canada, it will reduce both cost and completion risk.

3.2 *Tariff Setting Mechanism*

Tariffs paid to Alaska LLC, as owner of the Project, by shippers of natural gas pursuant to long-term "firm delivery" shipping contracts ("Firm Transportation Contracts") are an essential element of the Project because they provide the income stream that will service the debt and pay taxes on the Project and allow for a profitable return on the State's and the Producers' investment.

Counsel to the State has advised us that tariffs are set as part of a regulatory process administered by the Federal Energy Regulatory Commission ("FERC") and its Canadian counterpart, the National Energy Board ("NEB") (FERC and NEB are jointly referred to as the "Regulators"). The regulatory process will impact the financing of the Project in three ways:

- The open season process will create a competitive bidding mechanism for pipeline capacity that will result in Firm Transportation Contracts. (Note that due to the centrality

[10] Please note that Table 3 was taken from Section 7 of the Fiscal Interest Finding and that the figures in Table 3 do not total precisely $21 billion due to rounding.

of tariffs to the success of the Project, it is imperative, and in fact lenders will require, that the shippers under the Firm Transportation Contracts (which will likely be at least as long in duration as the debt) have strong credit ratings.)

- 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. Procurement of these certificates is particularly important to the financing of the Project because it is a condition for obtaining DOE Guarantees for the debt.

- 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 and risks and operating expenses of the Project. Shippers who have not signed Firm Transportation Contracts remain free to challenge the reasonableness of previously approved tariffs. The Regulators will not alter those tariffs, however, unless it is shown that they are no longer just and reasonable.

All three regulatory elements are critical to a successful financing of the Project, and achieving favorable regulation in the U.S. and Canada is a key factor for completing the Project.

We have been advised by counsel to the State that, based on current estimates, FERC will likely approve a tariff that provides a "reasonable" return to Alaska LLC in consideration of the risks of the Project (and that any such rate could be subject to a rate review by shippers who feel it provides too high a rate of return to Alaska LLC).[11]

We have been advised by the State's Canadian counsel that NEB will follow a similar rate-setting procedure.

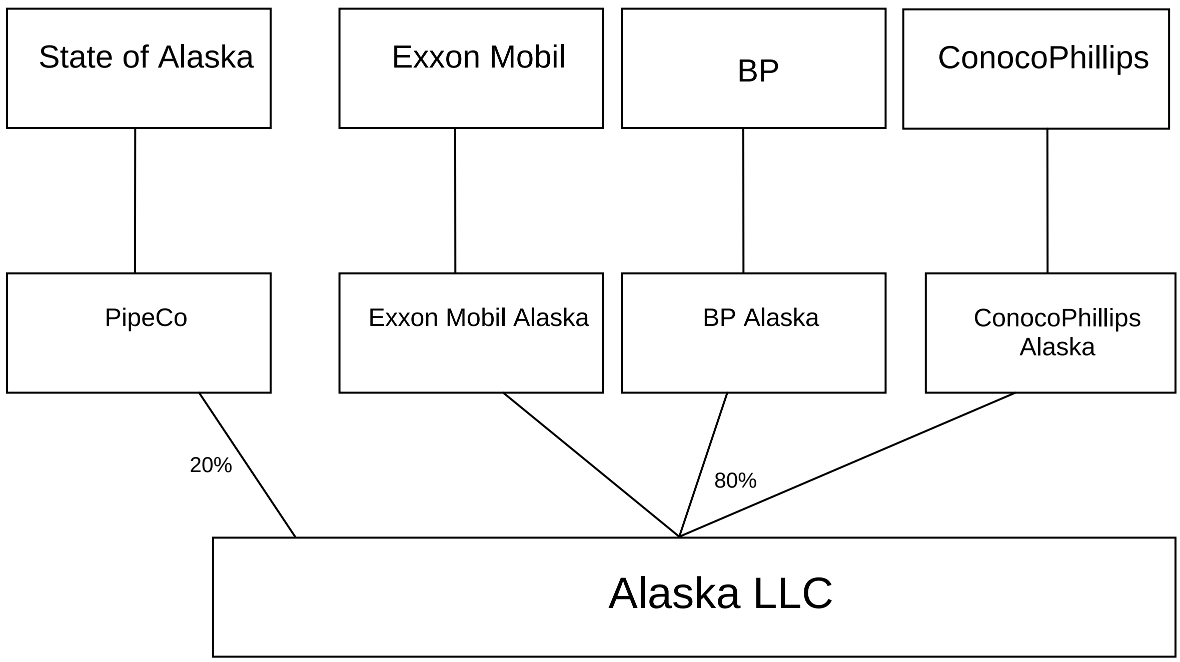
4. Corporate Structure

The State and the Producers will undertake the Project through one or more Project entities that they will form and own (directly or through intermediate entities formed by the State or an individual Producer), including Alaska LLC, which will own the Alaska segment of the pipeline. The basic structure of Alaska LLC is set forth in Diagram 1 below.[12]

[11] The State's counsel has noted that while it is fair to say that the returns on equity investments for FERC-regulated pipelines currently in service generally range between 12-14%, the uniqueness of this Project, together with the fact that the rate hearings will not be conducted for nearly a decade, means that any estimated return calculated at this early stage is highly unreliable.

[12] Please note that ownership allocations among the Producer Subs have not been finalized.

Diagram 1
Basic Structure of Alaska LLC



As reflected in the diagram above, the State expects to invest in Alaska LLC through PipeCo, which will directly own a 20% stake in Alaska LLC. As discussed above, the State expects to invest a minimum of $800 million as equity capital in PipeCo, which will, in turn, use the funds to make equity contributions to Alaska LLC for its share of Project costs. PipeCo may also form subsidiaries to own the State's interests in the other portions of the Project, such as the Canadian segment, the gas treatment plant, feeder lines and related facilities.

PipeCo 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. PipeCo 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 PipeCo investment.

Alaska LLC will be governed by a Management Committee. The Management Committee will select a Managing Member (the "Managing Member") to run the day-to-day business and affairs of Alaska LLC. An affiliate of the Managing Member will also be the operator (the "Operator") of the pipeline.

The important role that PipeCo will play in Alaska LLC's operations makes the formation, staffing, funding and start-up of PipeCo a critical path issue. We understand that the State and its counsel are working on next steps in this regard.

5. Funding Fundamentals and Financing Options

5.1 *Funding Fundamentals*

Key components of any debt financing of a project of this nature and size include (i) the degree to which the sponsors' equity investment in such a project will be leveraged with debt; (ii) the degree to which lenders to such a project will be able to rely on the sponsors for repayment of the debt if the borrower defaults; (iii) the nature of the security arrangements that support the financing; and (iv) the conclusions the rating agencies reach regarding the financial strength of such a project. Any lender to the Project will thoroughly analyze such components when weighing its decision to lend to the Project. Accordingly, each such component must be carefully considered in the course of developing the Finance Plan.

5.1.1. *Debt to Equity Ratio*

Financings of large mid-stream oil and gas projects have historically had a debt to equity ratio in the range of 70-80% debt, with 30-20% of total funds contributed as equity. In the case of this Project, given the robust projected revenue stream, the financial strength and technical expertise of the participants, and other considerations discussed further in this report, the Financial Advisors believe that an 80/20 debt to equity ratio is achievable in a scenario in which Alaska LLC acts as the borrower for the Project in a limited recourse financing (an "LLC Financing"). In an LLC Financing, 80% of total Project costs would be financed with the proceeds of debt incurred by Alaska LLC and PipeCo would only be responsible for its 20% share of the remaining 20% of total Project costs. If PipeCo and the Producer Subs elect to pursue a Member-level Financing, then (given the State's liquidity situation) PipeCo would need to borrow a significant portion of the $4 billion it would be obligated to contribute to Alaska LLC. In the case of either an LLC Financing or a Member-level Financing, PipeCo would contribute the remaining portion of its share of Project costs (after giving effect to such debt financing) in the form of equity upon the closing of such debt financing (or upon completion of the construction at the latest). As such, despite the fact that PipeCo is nominally responsible for 20% of the total costs of the Project (based on its ownership stake in Alaska LLC), by undertaking either an LLC Financing or a Member-level Financing, it could limit its "true equity" investment to between 4-6% of total Project costs.[13]

5.1.2. *Degree of Recourse (Completion Support by the State)*

Both the State and the Producers envision that they will establish special purpose entities (e.g., Alaska LLC) to undertake the Project, and it is understood by all participants in the Project

[13] Please note that lenders are not likely to finance more than 80% of the Project's estimated costs because they would want the State and the Producers each to have a sufficient economic stake in the Project so as to ensure prudent operation of the Project. PipeCo's borrowing capacity may be somewhat lower than would allow for an 80/20 debt to equity ratio if it borrows in its own name.

(including the lenders) that one of the primary purposes for establishing such special purpose entities is to limit recourse to the State and the Producers for the liabilities of such special purpose entities, including their debt obligations.

The degree to which lenders to the Project will require assets other than those directly associated with the Project (e.g., revenues from tariffs) to support the debt obligations of the entity borrowing to finance the Project is one of the many issues that the State and the Producers will face in the course of exploring debt financing options for the Project. The range of options available to the State in that regard include full recourse, limited recourse and, in very limited circumstances in a PipeCo Member-level Financing, non-recourse debt financing.[14] For reasons discussed below, the Financial Advisors believe that the State should elect to pursue (and should encourage the Producers to pursue) a limited recourse debt financing with Alaska LLC as the borrower.

In the context of this Project, where it is intended that Alaska LLC (or other special purpose entities) will undertake the Project, full recourse debt financing is any financing in which the lenders would, throughout the term of the debt, have recourse to creditworthy affiliates of Alaska LLC (e.g., the State and the Producers),[15] whether through guarantees of the debt obligations of Alaska LLC or otherwise. Thus, in a full recourse debt financing, if Alaska LLC were to default on its obligations (even if such a default were to occur after Project completion), the lenders would expect to be repaid by the State and the Producers. As such, the State and the Producers would be taking on both construction and operational risk for the Project, which would be both highly unusual and undesirable.

Historically, lenders have not financed oil and gas project level entities without some degree of completion support. Given the cost and complexity of this Project, there is no reason to expect otherwise in this case. Based on deal precedent (which requires sponsors of a project to assume some degree of completion risk), and the Producers' and the State's desire to limit their exposure, especially after completion of the Project, it is likely that any debt financing of the Project will be done on a limited recourse basis with the State and the applicable Producer providing a several guarantee of such debt. In an LLC Financing, the size of the State's guarantee would be based on PipeCo's share of Alaska LLC (i.e., the State would guarantee no

[14] In a non-recourse debt financing of the Project, the lenders would only ever be able to rely on the assets of the borrowing entity for repayment of the debt (including during the construction phase, when the Project is not generating any revenue). For example, if Alaska LLC borrowed on a non-recourse basis and defaulted on its obligations (e.g., it failed to construct the Project), its lenders would only be able pursue a judgment against Alaska LLC and foreclose upon the assets of Alaska LLC itself (i.e., the project facilities, bank accounts and contract rights) in an effort to repay the debt. As noted above, this would be a highly unusual structure for this kind of project, and the lenders are likely to be strongly opposed to assuming completion risk in this scenario.

[15] We note that the market is not as established with respect to whether a debt financing undertaken at the Producer Sub level (e.g., by PipeCo) would require completion support. Under a Member-level Financing, it is possible that the Producers would fund all or a very substantial portion of the Producer Sub's share of the total Project costs with equity. As such, the lenders to PipeCo may have more confidence that the Producers will be fully engaged and truly committed to completing the Project and thus may not require completion support from the State.

more than 20% of Alaska LLC's debt). In a Member-level Financing, the State would guarantee the full amount of PipeCo's debt until Project completion.[16]

Despite the difficulty of achieving a non-recourse LLC Financing, we note that, based on very favorable current market conditions and current estimates of Project costs ($20 billion), it might be possible that, in a Member-level Financing, debt for 70-80% of PipeCo's share of Alaska LLC's cash calls may be raised without the State providing completion support (i.e., through a non-recourse debt financing) so long as the remedies available to the Producer Subs for PipeCo's failure to fund cost overruns are as described above. However, when the actual financing is arranged in 3-4 years, market conditions may not be so favorable and the Project cost estimate may be significantly higher than $20 billion, thereby significantly increasing the likelihood that the State will need to provide completion support for such Member-level Financing by PipeCo.[17]

With regard to the construction phase, the lenders in a limited recourse debt financing would typically expect to see (i) a comprehensive guarantee of debt service prior to the completion of the facilities (that would be callable if the Project was not completed by a certain date); (ii) 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 (perhaps slightly less commonly) at least by the completion date (i.e., so that at completion the debt to equity ratio is at an agreed upon level)[18]; and (iii) a commitment to fund cost overruns (which risk the State and the Producers themselves may mitigate by agreeing on a fixed-price, turnkey engineering, procurement and construction contract ("EPC Contract")). The extent of recourse varies from project to project, with additional recourse sometimes being given (up to a specified cap) to bridge gaps in the risk allocation that lenders or other project participants are not willing to take. Even if not required to do so, sponsors sometimes elect to offer completion support because it reduces the need for costly due diligence by lenders regarding the construction phase and the construction contracts and because it potentially enables the sponsors to obtain more competitive terms on the EPC Contract (e.g., if the sponsor decides it can accept lower than usual liquidated damages/bonding than would otherwise be required if the lenders did not have recourse to the completion support). In any case, the State will want to carefully define the scope of any completion support liabilities and the mechanics and terms under which they are released from these obligations in its discussions with the Producers and the potential lenders.

Several factors help mitigate the risk inherent in the State providing completion support. One such factor is that the Producers and the State will be aligned in their desire to have the Project

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[16] Please note that any completion guarantees or other completion support provided by the State to support debt incurred by Alaska LLC will be pro rata based on PipeCo's equity share in Alaska LLC and, subject to negotiations with lenders and the other Members, we would expect such completion support obligations to be adjusted, as necessary, to reflect any reduction in PipeCo's equity share in Alaska LLC (whether as a result of failure to make cash calls due as a result of cost overruns or otherwise).

[17] Other factors, such as a decision by one or more of the Producer Subs to seek debt financing to fund its interest in Alaska LLC, could also have negative repercussions for PipeCo's efforts to procure debt financing without the State providing completion support since there might be a capacity constraint in the market and the lenders may be less sanguine regarding the commitment of the Producers to the Project.

[18] When equity is not invested on day one, there may be some negotiation as to the ability of the lenders to accelerate the equity commitment in the event of a default during the construction period.

completed on schedule and within budget. The Producers have vast experience with these kinds of mega-projects and have an impressive track record of hitting schedule and budget targets. We assume the Producer Subs, through the Managing Member or the Operator, will engage experienced contractors to construct the pipeline and will manage the Project for the benefit of all the Members.

There are also a number of additional measures that can be implemented to (i) address completion delay and cost overruns and (ii) mitigate the risk that debt incurred by either Alaska LLC or PipeCo will ever be accelerated by the lenders. Such measures include the following, none of which should be objectionable to the Producers in an LLC Financing scenario where they would have some completion support obligations,[19] and some of which are within the State's control to negotiate with its lenders in a Member-level Financing by PipeCo:

- Ensure that the Project budget and finance terms agreed upon with the lenders provide substantial cushion for delays prior to the trigger event when the lenders can accelerate and demand repayment of the loans. Based on precedent, the State can assume there will be at least a 2-year cushion for delays after the "scheduled completion date" before the lenders would have the right to accelerate the debt, as well as the possibility for some period (roughly another year to 18 months) during which the provider of the completion support will only need to cover debt service before the lenders can exercise their right to accelerate.

- Make the test defining "completion" of the Project as easy as possible. For instance, as long as the pipeline is operational and debt is being paid currently, then the lenders would not have the right to accelerate the debt.

- Have a significant debt service reserve account (e.g., 12 months) with sufficient funds to carry the Project through a significant delay in start-up or other problems. In most cases, the cost of funding such a reserve account is included within the financing.

- Consider including a right for the Members (or the State, as applicable) to buy down the debt if the completion test is not met, which, upon making such a buy-down, would result in a "deemed completion" of the Project such that thereafter the debt would be non-recourse (but with a lower amount of debt).

- Structure the EPC Contracts so that the contractors pick up a portion of the completion risk (this approach is common in electricity sector transactions, but not as typical for pipeline or other oil and gas transactions).

- Obtain business interruption insurance.

As the Project progresses, the Financial Advisors (in conjunction with the Finance Committee in the event of an LLC Financing) will assist the State in developing and refining its strategy for

[19] On cost management issues such as EPC Contract price, procurement of business interruption insurance and debt service reserve requirements, the Producers might be less conservative than the State.

negotiating the parameters of the State's limited recourse completion support obligations with potential lenders.

5.1.3. *Firm Transportation Contract Assignment and Other Security*

Regardless of the lenders' degree of recourse to the State and the Producers, the lenders will expect that Alaska LLC or PipeCo, as applicable, will provide collateral for its obligations to such lenders. The kinds of security packages available to the lenders will vary depending on whether the debt financing is done as an LLC Financing or a Member-level Financing.

Under an LLC Financing, the lenders would ordinarily expect, among other things, a pledge and/or assignment of the following collateral:

- Alaska LLC's Firm Transportation Contracts.
- Alaska LLC's revenues.
- Membership interests in Alaska LLC.
- Certain assets of Alaska LLC (including contract rights).[20]
- Project accounts.

Under a Member-level Financing, the lenders to PipeCo would ordinarily seek a pledge and/or assignment of the following collateral:

- Dividends to PipeCo from Alaska LLC (i.e., 20% of net profits of Alaska LLC).
- PipeCo's 20% membership interest in Alaska LLC.
- Possibly, the Firm Transportation Contract between Alaska LLC and the State's shipper affiliate.

5.1.4. *Historic Context/Examples*

As noted above, the vast majority of debt financings for significant oil and gas projects undertaken in the past decade have been on a limited recourse basis. These projects include:

- *RasGas II/3 Financing*: Ras Laffan Liquefied Natural Gas Company Ltd. (II) and Ras Laffan Liquefied Natural Gas Company Ltd. (3), joint ventures formed by Qatar Petroleum and ExxonMobil, raised $4.6 billion in the initial phase of financing for a 5 train LNG project. The initial financing included a capital markets offering of bonds, a commercial bank facility and significant sponsor senior debt.
- *Tengizchevroil*: Tengizchevroil LLP ("TCO"), a large oil company in Kazakhstan owned by Chevron, ExxonMobil, KazMunayGas (the state-owned oil and gas company) and

[20] Please note that it is not practical (and thus it is unusual) for lenders to take a security interest over the physical assets of the project company (e.g., Alaska LLC) in a pipeline project.

LUKARCO raised $4.4 billion (a capital markets offering of $1.1 billion and $3.3 billion in sponsor loans) that is being used to expand TCO's oil production to approximately 540,000 barrels of crude oil per day.

- *NGL II Expansion Project*: The Nigerian National Petroleum Corporation (the state-owned oil company of Nigeria) and an affiliate of ExxonMobil sought financing in connection with the $1.2 billion expansion financing of a natural gas liquids project on Bonny Island, Nigeria. The financing involves debt provided by Credit Suisse First Boston and a syndicate of Nigerian banks, a portion of which is guaranteed by the Overseas Private Investment Corporation.

- *Hamaca Crude Oil Project*: Affiliates of Petróleos de Venezuela, S.A. (the national oil company of Venezuela), Conoco Phillips and Chevron undertook an approximately $4 billion, 200,000 bpd extra heavy crude oil recovery and enhancement project in Venezuela. The financing for the project included a bank facility guaranteed by the Export-Import Bank of the United States and an uncovered commercial bank facility.

5.1.5. ***Rating Agencies***

5.1.5.1. *Credit Fundamentals*

An important element of any debt financing of a project such as this one is how the rating agencies analyze both the project and the risk that lenders will not be repaid. The rating agencies regularly rate projects and there are a large number of factors they will consider in their analysis of the Project and the debt financing thereof. These factors can be divided into two groups. First, there are the factors that the rating agencies openly state as essential to the analysis of an entity's credit. These stated factors include the following: (i) technical or project level risk; (ii) force majeure risk; (iii) sovereign risk; (iv) institutional risk; and (v) credit enhancements. Second, there are additional factors that are not specifically articulated by the rating agencies, but that may be applied on a project-by-project basis. These additional factors may include the following: (i) the rating agencies' familiarity with the financing structure associated with the project; (ii) the expertise of the project sponsors; and (iii) the financial strength (and credit ratings) of the project sponsors.

With some caveats, it is safe to say that the rating agencies are likely to view the Project as quite strong. It has very strong credit fundamentals and its scores well with respect to the "soft" concerns as well.

<u>Technical or Project Level Risk</u>

The rating agencies will consider the intrinsic or fundamental nature of the project and industry. Essentially, this is a consideration of the quality and strict control of the available project cash flow from operations. On this front the Project is likely to receive a favorable review. The Producers and the State have invested a tremendous amount of time (over 30 years) and money (at least $125 million) for the purpose of determining that the Project is fundamentally sound and worth undertaking. The gas industry is seen as strong, and the Producers bring a tremendous amount of expertise to the table. The involvement of the State also helps reduce regulatory and other implementation concerns that are important in pipeline development projects.

Force Majeure Risk

The rating agencies will consider the exposure to unmitigated, unanticipated outside events, including but not limited to war, weather and catastrophe. In general, for pipeline projects, this risk is affected by the geographic size of the project and the likelihood of an event that could materially impact operations.

Despite the enormous geographic scope of the Project, there are a variety of factors that should minimize the rating agencies' concerns regarding force majeure. First, the Project is being constructed in two highly stable countries that are strong allies (the United States and Canada). In addition, the pipeline will be buried and, generally, located in extremely remote areas of the world. Thus, in addition to the monitoring protocols that will be in place for ensuring the security of the pipeline, these fundamental physical barriers should insulate the Project from most kinds of human-related force majeure. The existence of various other pipelines in the area where the Project will be located also suggests that, despite the harsh climate of the region, weather should not be an overly negative consideration for the rating agencies.

Sovereign Risk

The rating agencies will consider foreign currency risk, which is largely eliminated for U.S.-based projects such as this one.[21]

Institutional Risk

The rating agencies will consider the resoluteness and strength of the legal and political environment of the location of the project. Again, this risk is largely eliminated for U.S.- and Canadian-based projects, except, potentially for permitting risk.

Credit Enhancements

The rating agencies will consider whether financial guarantees, such as monoline insurance or, in the case of this Project, DOE Guarantees, are utilized to enhance recovery in the event of default. The utilization of DOE Guarantees, bond insurance and, possibly, completion support from the State and the Producers, should all contribute to a positive view by the rating agencies on the question of credit enhancements for the Project.[22]

Familiarity of Financing Structure

Secured, limited recourse financing has been the financing vehicle of choice for the vast majority of significant greenfield, mid-stream oil and gas projects around the world during the past 10 years.

[21] Further consideration is required with respect to foreign currency risk for the Canadian portion of the Project.

[22] Please note that, as discussed more fully below in Section 5.3.5 and Section 6, while these credit enhancements may assist in achieving a better credit rating, because they would insulate lenders from borrower payment defaults, they would not relieve the borrower of the ultimate obligation for repayment of the debt.

<u>Expertise of Project Sponsors</u>

On this count the Producers are seen as exceptionally strong and thus may give a noticeable boost to the rating agencies' conclusions. By contrast, we have been advised by Government Finance Associates that the rating agencies view the State's participation in the Project with more skepticism in this regard because the State's day-to-day business is not in the oil and gas development sector. It is possible that this skepticism could color slightly their otherwise positive conclusions regarding the expertise of the sponsors, but we also understand from discussions with Government Finance Associates that this concern would more likely arise in the context of a Member-level Financing.

<u>Financial Strength (and Credit Ratings) of Project Sponsors</u>

Again, each Producer is among the largest and most profitable companies in the world and each has an extremely strong credit rating. The State does not have comparable annual revenues and, at least nominally, does not benefit from as strong a credit rating as certain Producers. This second issue however may be somewhat offset by the fact that, as described more fully below, the credit ratings of the Producers and the State are not directly comparable.

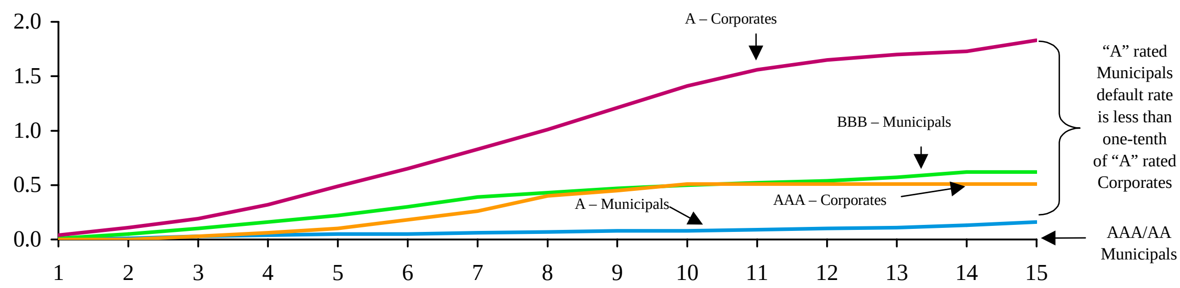
5.1.5.2. *Corporate Equivalence*

Although the State may carry a lower nominal municipal rating than the Producers, the credit ratings are not directly comparable**.** Responding to investor and issuer complaints about the lack of consistency in ratings, all three major rating agencies have begun to examine the comparability of their ratings across different sectors. They have each acknowledged the wide divergence in the risk of default and loss between municipal bonds and comparably-rated corporate or asset-backed credits. The discrepancy between ratings across sectors is most acute between high-grade municipal bonds and corporate bonds.

Moody's has published papers regarding the lack of direct rating comparability. Accordingly, Moody's has begun to issue corporate scale ratings for select municipal credits and is the only one of the three major rating agencies to do so. They are relatively restrictive about the practice, limiting its application to taxable deals with cross-border marketing (or, at least the expectation of cross-border marketing). For a corporate equivalent rating, Moody's will only publish a brief rating statement, and may not update the rating further, even when the municipal ratings change.

The corporate equivalent rating from Moody's would be very useful in marketing to the taxable domestic and global investor base. Moreover, such corporate equivalent rating will also be very helpful in setting capital charge weightings for taxable bonds with the Office of the Comptroller of the Currency. Until 2005, it was Moody's practice to assign a corporate scale rating of one full category above the municipal rating – for example, an A1 became an Aa1 corporate scale rating. The practice changed in May 2005 when the Detroit pension deal (an appropriation-like credit) was rated Baa1 (for Detroit's general obligation credit) on the municipal scale and Aa1 on the corporate scale – a full 2 category discrepancy. Were the State to issue debt secured by the project dividends for a portion of its equity contribution, such debt would likely also carry a moral obligation from the State to replenish a debt service reserve fund. Historically, Moody's has only issued corporate equivalent ratings for general obligation and appropriation credits. Although requesting equivalent ratings for this issue would entail negotiations with the ratings community, the Financial Advisors believe that an appropriately structured transaction could carry an Aaa corporate equivalent rating from Moody's. This equivalent rating may be helpful in demonstrating to the rating agencies that the State's credit is on par with that of the Producers. S&P and Fitch have not formally noted the discrepancy between the likelihood of default between municipal credits and corporate credits. S&P has released studies focusing on transitions or the probability of changes in ratings and cumulative default rates for public finance and corporate credits. A 2001 study showed that an A rated municipal bond is less than one-tenth as likely to default over a fifteen-year period as an A rated corporate bond. Additionally, default rates for BBB municipals are close to default rates for AAA rated corporates. However, S&P has not made any attempt to harmonize its ratings. Diagram 2 below shows average cumulative default rates over a 15-year period.

Diagram 2
Average Cumulative Default Rates



Note: Default rates in percentages over a 15-year period
Source: S&P Default Report, 2001

Fitch reports have noted the discrepancy between default rates for corporate bonds and cumulative default rates for various sectors of the municipal market over similar periods. In response to this discrepancy, Fitch has begun upgrading sectors of the municipal market which it views as extremely low risk. Fitch has asserted a policy focusing on the probability of default, not the likelihood of ultimate recovery. They have noted that highly rated municipal credits tend to provide for full recovery.

5.2 *Financing Options*

The State and the Producers are exploring a full range of financing structures and options at this time. In evaluating these possible financing structures, the State and the Producers will select the structure that most comprehensively satisfies each of their goals. The State's finance objectives include the following (which the Producers share, to varying degrees): (i) limit the State's liability (whether such liability results from provision of completion support or otherwise) for the funds borrowed for Project construction so as to mitigate the impact the Project will have on the State's credit rating, borrowing capacity and cost of borrowing; (ii) approach the market in concert with some or all of the Producers so as to obtain the best financing terms available; (iii) utilize the DOE Guarantees available under ANGPA (if the final terms of such DOE Guarantees negotiated with the Department of Energy are acceptable) to lower the cost of borrowing and increase the likelihood that the State and the Producers can finance 80% of estimated Project costs; and (iv) 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.[23]

In consideration of the foregoing finance goals, the State will also need to evaluate (i) the nature, structure, timing and procurement strategy for the debt component of its financing; (ii) the amount, timing and sources for its equity contribution; (iii) how it will address cost overruns; and (iv) the potential net cash flows to the State from the Project.

At this time, and for the reasons more fully described below, the Financial Advisors have concluded that a traditional project financing with Alaska LLC as the borrower would best achieve the finance goals set forth above.[24]

5.2.1. ***Debt Financing – Alternative Funding Mechanisms***

5.2.1.1. *Nature of Financing: Degree of Recourse*

As discussed in more detail above in Section 5.1.2, it is anticipated that if either an LLC Financing or a Member-level Financing is undertaken to fund Project costs, then such debt financing will be done on a limited recourse basis with completion support provided by the State and the Producers (or a sub-set thereof, in the case of a Member-level Financing with less than all Producer Subs participating) during Project construction.

Through a limited recourse debt financing, the State's obligation to repay Project-related debt would be a contingent liability only. Limiting the State's liability for the debt of the Project is particularly important because, given the size of the Project debt, such liability might negatively affect the State's borrowing capacity and, therefore, its credit rating and cost of borrowing. Such negative impacts could be felt not only at the State level, but also at the municipal level (to the extent that lenders to municipalities believe that the value of the State's support of municipal debt is compromised by its obligations with respect to the Project debt).

5.2.2. ***Structure of Financing:*** *Traditional Project Financing vs. Member-level Financing*

5.2.2.1. *LLC-level Traditional Project Financing*

From a structuring perspective, there are a number of advantages associated with incurring the debt to finance the Project through an LLC Financing. Specifically, the advantages include the following:

[23] The State has an interest in lowering the tariff because in addition to acting as an owner of the Project through PipeCo, it will also be a shipper (i.e., the party paying the tariff) through another to-be-formed subsidiary.

[24] While the State and the Producers have some common finance objectives, they also have individual concerns (e.g., 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 Producers 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.

- An LLC Financing would be relatively simple to structure (thus reducing legal fees and other transaction costs).

- There would be few, if any, issues associated with pledging the Firm Transportation Contracts and other assets of Alaska LLC to support the debt.

- The lenders would consider the "blended credit" of all the shippers (affiliates of the State and the Producers)[25] under the Firm Transportation Contracts when assessing the stability of Alaska LLC's revenue stream.

- It is a very common structure and thus easy to explain to lenders and the rating agencies.

- The State would benefit from having the Producers involved in the debt financing (e.g., the Producers' experience and market strength could be applied during negotiations with lenders to procure favorable pricing and other terms).

The disadvantages associated with an LLC Financing as compared to a Member-level Financing or no debt financing are, in general, not as relevant to the State as they are to the Producers. Specifically, it may be difficult for the Producers to optimize their respective tax positions under an LLC Financing. In addition, an LLC Financing structure likely would not allow for allocations of the benefits from the Producer Subs to PipeCo. Moreover, an LLC Financing would not allow the Members to avoid the costs of borrowing, the restrictions that lenders will place on the business and operations of Alaska LLC, and other transaction costs. Note that in the case of a Member-level Financing some of these disadvantages may still apply to a Member that elects to pursue debt financing for its share of Project costs. If the Members are permitted to opt out of Member-level Financing, then Members that opt out of such debt financing will also avoid most, if not all, of the aforementioned disadvantages.

While project finance structures differ depending on the specifics of the project to be financed (e.g., industry sector, technology, construction risk, political risks and project economics), there are certain common elements that the State should expect would be applicable to an LLC Financing of the Project (but such elements are not certain, as the terms will be subject to negotiation):

- The lenders will make their loans based on their analysis of the expected cash flow from operations of Alaska LLC (rather than from the creditworthiness of the State and the Producers (except to the extent completion support is required)). As noted above, in analyzing such expected cash flow, key issues will include (i) the creditworthiness of Alaska LLC's shippers, whose "blended credit" underpins the expected revenue stream from the shipping contracts; (ii) the strength of the terms of the Firm Transportation Contracts; and (iii) regulatory matters (including permitted recovery of capital costs and rate of return on capital under a tariff approved by FERC or NEB, as applicable, for the Firm Transportation Contracts).

[25] The State, either directly or through a State entity to be formed, will establish a gas marketing arm that will be a shipper and enter into a Firm Transportation Contract with Alaska LLC with a FERC-regulated tariff.

- 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 Producers or its Members' assets.[26] Rather, the lenders will be able to look only to the revenues and, in a default scenario, the real and intangible assets of Alaska LLC (i.e., the Project facilities, bank accounts and contract rights, including the Firm Transportation Contracts)[27] and possibly the State's interest in PipeCo and the Producers' interests in their respective Producer Subs.

Rating Agency Analysis of LLC Financing

If the State and the Producers achieve an LLC Financing with the characteristics described in the preceding section, then the rating agencies are likely to look at the Project more favorably in several respects than they would if a Member-level Financing were undertaken. First, although the Project economics (including strength of Firm Transportation Contracts and the credit of the shippers) will be the cornerstone of the rating agencies' analysis of both an LLC Financing and a Member-level Financing,[28] there will be a "halo effect" from participation of the Producers (through the Producer Subs) in the Project, whose robust credit ratings should push up the rating ascribed to the Project. Conversely, in a Member-level Financing, the State's credit rating will effectively cap the rating to be ascribed to PipeCo debt.

Second, the impact on the State's borrowing capacity and credit rating (and cost of borrowing) as a result of its participation in the Project will be significantly less under an LLC Financing than if the State (or PipeCo) were the borrower of 20% of the total Project costs. When using an LLC Financing, this benefit is expected to exist even during the construction phase, when the State bears contingent risk for repayment of a pro rata portion of Alaska LLC's debt. The credit rating agencies have traditionally viewed a call on completion support provided by project sponsors in an LLC Financing as a fairly remote risk and have evaluated the impacts on the credit ratings of entities providing such support accordingly.

However, in a Member-level Financing, the debt of PipeCo, a 100% subsidiary of the State, will certainly be factored into the credit rating agencies' analysis of the State's overall debt

[26] Another possible structure is for Alaska LLC to obtain interim construction debt (supported by the State and the Producers) that will be refinanced at Project completion with long-term debt that is non-recourse to the direct and indirect owners of Alaska LLC. Alaska LLC and its Members will evaluate market conditions and available financing options in making a final determination as to whether construction or long-term financing will be selected.

[27] In an LLC Financing, Alaska LLC's rights under the Firm Transportation Contracts with the shippers (which will be affiliates of the State and the Producers) will be pledged to the lenders as collateral for the loans. In a Member-level Financing with PipeCo as the borrower, the State's gas marketing arm's Firm Transportation Contract with Alaska LLC might be pledged to the lenders to provide financing to PipeCo (though this will require the consent of the other Members of Alaska LLC since such contract is an asset of Alaska LLC, not PipeCo). As noted above, we do not believe that the Producer Subs would be inclined to grant such consent.

[28] Considerations weighed by the rating agencies are more fully described in Section 5.1.5 and immediately below.

exposure.[29] This is especially the case during the construction phase, when the rating agencies – who will view the State as integral to PipeCo's future business and economic interests and committed to its success – will consider any construction delays and/or cost overruns as negative factors in their evaluation of the State's credit picture. The credit rating agencies are also likely to place greater scrutiny on the State's ability (e.g., experience, expertise and management program) to implement the Project if there were a Member-level Financing (especially if not all of the Producer Subs participate in a coordinated Member-level Financing) than if there were an LLC Financing where the State would be perceived as relying on the expertise of the Producers for Project management and implementation.[30]

The State's outstanding general obligation and certificate of participation debt as of June 30, 2005 was $584.2 million. In addition, the State has nearly $1.0 billion in guarantees and other obligations outstanding, which bring the total current State net tax-supported debt to approximately $1.5 billion. 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 repayment from resources other than from Project revenues (e.g., 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 as to warrant a downgrade of the State's credit rating.[31] 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 5 to 50 basis points depending on market conditions at the time. 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.

<u>LLC Financing Encourages Member Cooperation in Approaching the Market</u>

In an LLC Financing, the Producers and the State would jointly approach the market for financing for Alaska LLC since each of them has a vested interest in Alaska LLC getting the best available pricing and terms. Approaching the market jointly with the Producers is advantageous for the State because the Producers have extensive experience in complex financings for major oil and gas projects and are considered "pros" by the financial markets and credit rating agencies in closing large scale financings. As mentioned above, if the State and the Producers pursue an LLC Financing, the State would have the benefit of the Producers' collective experience and market strength to negotiate favorable pricing and other terms.

5.2.2.2. *Member-level Financing (with Varying Degrees of Cooperation)*

As noted above, Article XI of the LLC Agreement provides the Members with the flexibility to select (subject to voting requirements) whatever financing option they deem most advantageous,

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[29] Government Finance Associates has advised that this will be the case whether or not PipeCo debt actually appears on the State's formal debt statement.

[30] This added scrutiny is likely to occur even though the Producers would still, under the LLC Agreement, lead the Project management.

[31] Please note that we have been advised by the State that the State does not currently contemplate using general obligation debt to finance the Project.

and that, if agreement is not reached, each Member may separately finance its portion of Project costs. Based on the discussions to date between the Producers and the State on financing options, the Financial Advisors believe that the Producers are likely to propose a Member-level Financing structure (as an alternative to an LLC Financing) that looks like the following:[32]

- Each Member (or a finance affiliate of such Member) would borrow its pro rata share of the financing needed by Alaska LLC, and such Member would be severally obligated to repay its lenders.

- Each Member would contribute to Alaska LLC 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.[33]

- Each Member would cause Alaska LLC to assign to such Member's lenders its rights under the Firm Transportation Contract between Alaska LLC and such Member's shipper affiliate.

- The creditworthy sponsor affiliated with each Member (i.e., the State and the Producers) 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.

While it is worth noting that both Member-level Financing and LLC Financing could be achieved on a limited recourse basis, and that the Project's economics will still be the primary basis for evaluation of credit, there are some important differences between these financing structures. These distinguishing features include the following:

- Due to the different credit ratings of each Member, the tenor, terms and applicable interest rate of each Member's financing could be different, and in negotiating such terms, the State would not likely have the benefit of as strong a "halo effect" from the participation of the Producers.

[32] 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 report common to many structures only as an illustrative example to provide a better understanding of the differences between a project financing with Alaska LLC as a borrower (i.e., an LLC Financing) 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 Alaska LLC, pledged as collateral for other Member's debts). Moreover, as fewer Producers participate in the debt financing of the Project, PipeCo's ability to leverage its investment and otherwise achieve favorable terms may be diminished.

[33] Whether or not the funds are contributed as equity to Alaska LLC or on-lent depends on whether the other Members also adopt Member-level Financing.

- As a wholly-owned subsidiary of the State, PipeCo's debt will certainly be factored into the credit rating agencies' analysis of the State's overall debt exposure.[34]

- The debt to equity ratio that can be achieved by PipeCo might be less than that achievable by Alaska LLC (e.g., 70/30 instead of the targeted 80/20).

- The collateral granted to the Members' respective lender groups would not consist of all of the Firm Transportation Contracts, but rather would consist of Alaska LLC's rights under the Firm Transportation Contract with each Member's respective shipper (e.g., BP, as borrower, will cause Alaska LLC to collaterally assign to BP's lender group Alaska LLC's right to receive payments under the Firm Transportation Contract between Alaska LLC and BP's shipper affiliate), subject to the agreement of any Members not participating in such Member-level Financing.

- Most likely, there would be "common" covenants and other restrictions with respect to Alaska LLC for the benefit of the lenders under each Member-level Financing, but the covenants of each Member would stand alone and the default provisions of each financing would isolate each Member from the risk associated with any default by another Member (i.e., BP's financing would <u>not</u> be defaulted if a default arises solely under another Member's financing, but each Members' financing could be defaulted in the event of a default common to all Members).

- There would be intricate intercreditor provisions in each Member's financing limiting the rights of such Member's lenders to exercise remedies and specifically restricting the exercise of remedies to such Member and its collateral.

<u>Cooperation Under Member-level Financing</u>

Although Article XI of the LLC Agreement requires cooperation of the Members with respect to the LLC Finance Plan, as a practical matter, the level of cooperation in a Member-level Financing is likely to be considerably lower than if all Members were participating in the same debt financing. Furthermore, a Member-level Financing raises additional concerns regarding the level of cooperation required with respect to pledging collateral that are unique to Member-level Financing, especially if not all of the Producer Subs are participating in the financing. The advantages to approaching the market jointly in a Member-level Financing are somewhat ambiguous and are likely to be less convincing to the Producers. In light of their sensitivity towards "subsidizing" the State's borrowing by joining the State in its financing efforts, it seems probable that adopting Member-level Financing in the LLC Finance Plan could mean that the State would approach the market alone; in any event, the default financing plan is a Member-level Financing. Such an approach could be relatively disadvantageous for the State for the reasons discussed above.

[34] Government Finance Associates has advised that this will be the case whether or not PipeCo debt actually appears on the State's formal debt statement. A more complete analysis of how the rating agencies will consider the State's involvement in a Member-level Financing is set forth in Section 5.1.5.

5.2.2.3. *Further Considerations Regarding Structure; LLC Financing v. Member-level Financing.*

In addition to the points discussed above, if Alaska LLC does not pursue an LLC Financing and PipeCo is required to pursue its own financing through a Member-level Financing structure, there are a number of significant obstacles and challenges that should be considered by the State.

Capital Required

The State would be required to raise significantly more money through PipeCo than would be the case if Alaska LLC undertakes an LLC Financing (20% of the total Project costs vs. PipeCo's equity requirements). If Alaska LLC pursues an LLC Financing, PipeCo would only be obligated to fund 20% of Alaska LLC's total costs after taking into consideration the funds raised by Alaska LLC in its LLC Financing (i.e., 80% of the Project costs would be funded by Alaska LLC's lenders). If Alaska LLC is able to borrow 80% of the Project costs, PipeCo would only need to contribute to Alaska LLC 4% of the total Project costs. Note that, as discussed above in Section 5.1.2, in the case of an LLC Financing, the State would almost certainly be required to provide completion support to Alaska LLC's lenders for its pro rata share of Alaska LLC's debt and would likely be required to provide completion support for PipeCo's debt in a Member-level Financing.

Liquidity

The State's ability to readily access billions of dollars is not equivalent to the Producers' ability to access such funds. The Financial Advisors conducted an initial analysis of the State's ability to raise $4-8 billion (the range of expected costs for PipeCo's 20% share of Alaska LLC's anticipated Project costs)[35] and looked at various options (including involvement of the Permanent Fund as a provider of debt or equity for cost overruns, as more fully described in Section 7) for funding the State's funding obligations. The Financial Advisers have concluded that at the high end of the range of potential Project costs, there is a significant risk that the State will not be able to raise sufficient debt to cover its cash call obligations (or raise debt on terms acceptable to the State).

Penalty

Given the penalties for missing a capital call that may be available to non-defaulting Members under the final version of the LLC Agreement, the State must have sufficient funds arranged (for both its share of Alaska LLC's expected costs and possibly cost overruns), which would, based on current estimates, range from $4-8 billion. The remedies available to non-defaulting Members upon the State's failure to meet cash calls may require the State to take a conservative view as to Project costs and arrange for a financing that may be in excess of what ultimately will be needed. If it does not properly manage such cost overrun risk, then the State may find itself in a position in which sizeable cost overruns require the State to raise additional debt, and the failure to fund the cash calls associated with such cost overruns in a timely manner results in,

[35] Although our initial discussions with banks have been generally positive, banks are not prepared to make any commitments at this juncture and will require that the Project be considerably more developed and detailed before doing so.

among other things, a possible sale of PipeCo's interest in the Project to the Producer Subs at a discounted price.

Construction Risk and Operational Risk

In a construction project of this magnitude, there are numerous factors (e.g., change in Federal law, natural disasters, volatility in the steel and other commodity markets) that could have a significant impact on the total construction cost. Moreover, at this stage the Members do not have an up-to-date estimate of the expected construction costs. In light of the factors mentioned above regarding PipeCo's borrowing capacity, increased Project costs could present a significant problem with respect to PipeCo's ability to fund cash calls.[36]

5.2.3. ***Timing of Financing***

The timing of the debt financing for the Project is another factor for the State to consider before casting its vote on the Finance Plan. One option is for Alaska LLC to obtain interim construction debt (supported by several completion support obligations from the State and Producers) that will be refinanced upon completion of the Project with long-term debt that is non-recourse to the direct and indirect owners of Alaska LLC. The other option essentially is the limited recourse approach discussed above in Section 5.1.2, whereby the long-term debt would be incurred at the inception of the Project, but the completion support of the State and the applicable Producers would fall away upon Project completion. The State (with the assistance of the Financial Advisors) and the Producers will evaluate market conditions and available financing options in making a final determination as to which of the foregoing options will be selected.

5.2.4. ***Procurement of Financing***

When considering its financing options, the State should also think about its strategy for approaching the market. Options for engaging lenders include a competitive bid process or a negotiated selection. Although a competitive bid process may result in a wider array of lender offers and include a variety of financing terms, structures and pricing, a negotiated selection may be more efficient and orderly and may result in materially similar terms. The details of a negotiated selection versus competitive bid process are more fully described in Section 5.3.6. The State should also consider the timing of its approach to the market as well as what other factors may influence the analysis of potential lenders. In any case, the Financial Advisors will assist the State in seeking the best debt financing terms and pricing for the State from potential lenders and in dealing with the rating agencies; however, it is worth noting again that the State would also greatly benefit from approaching the market with the Producers at its side.

5.3 ***State's Equity Contribution***

There are several options currently under consideration for financing the State's equity investment of approximately $800 million in the Project. To help the State understand its options in this regard, the Financial Advisors have identified the following four possible sources of funds for the State's investment in PipeCo:

[36] In terms of operational risk, the Members would be obligated to make additional equity contributions after the in-service date.

- Proceeds from a direct appropriation from the State's general fund.
- Proceeds from the issuance of State bonds.
- Funds available under a revolving loan facility.
- Proceeds from the Permanent Fund as an equity investor or a lender. The State is also considering whether the Permanent Fund should be given the option to take a role as an equity participant or lender in the Project, which is more fully discussed in Section 7 below.

The form and priority of these equity funds will have credit implications for the State and ultimately will influence the success of the Project. From the equity contribution perspective, immediate funding certainty should not be confused with immediate funding need. It is important to understand that the State may not need to fund the entire amount upon closing the debt financing for the Project, but please note that the lenders will require a commitment to fund (in the form of an equity contribution agreement). The timing of such a contribution will be a subject of negotiations. Nevertheless, it is critical that the State have access to a liquid source of funding (e.g., a revolving facility or a well-funded account) so it can fund Alaska LLC's cash calls on PipeCo during Project development. In addition, the State may want to seek a more permanent source of funding (e.g., the proceeds of a bond financing) to create a reliable source of funds. The State's decision regarding the source of funds for the State's investment in PipeCo may have credit implications both in the immediate term and over the life of the Project. In addition, the different sources of funding options also have policy and cash flow implications for the State.

In light of the various cost and flexibility profiles of each of these options, the State should consider what factors (e.g., timing and implementation) would optimize their value and minimize credit implications for the State. The Financial Advisors consider the optimal timing for utilizing the sources described above as whatever sequence of funding best balances the cost of borrowing with maximum financing flexibility.

5.3.1. ***Direct Appropriation***

In the early stages of Project construction, the timing and magnitude of expenses can be unpredictable. Accordingly, it is important for the State to have ready access to substantial funds during this period. The State has advised the Financial Advisors that a direct appropriation of the funds required for equity contributions to Alaska LLC from the State's budget surpluses is the preferred option because it is the simplest and most straightforward. Specifically, on an annual basis, the Alaska State Legislature (the "<u>Legislature</u>") would appropriate the funds and deposit them into a trust that would be available only for the purposes of funding PipeCo's share of Project costs. There is ample precedent for such appropriations given that this is the manner in which most State-owned corporations have been capitalized. Direct appropriation would also provide the State with maximum flexibility to deal with cost overruns.[37] A sample of prior legislative appropriations capitalizing State corporations is shown below:

Corporation	Amount
Alaska Industrial Development and Export Authority	$325,000,000
Alaska Housing Finance Corp.	1,070,000,000
Alaska Student Loan Corp.	307,000,000
Total	**$1,702,000,000**

Thus, direct appropriation from the general fund appears to offer the most accessible and least costly source of funds during the early stages of Project construction. Another benefit of using direct appropriation is that it will enable the State to avoid borrowing money from other sources (i.e., interest-bearing loans or bonds) sooner than necessary and thereby may reduce the State's overall cost of borrowing.

The use of direct appropriation to pay for Project costs raises a variety of issues, including the extent to which the rating agencies will be concerned with how the State spends its surplus. Given the volatile nature of the State's revenues, the rating agencies will pay more attention to Alaska's use of surplus funds than is the case with other states. However, considering the alternative uses of surplus funds[38] and the projected benefits to the State from the Project (as discussed more fully in Section 2), development of the Project appears to be a justifiable and prudent use of the State's budget surplus.

Among the investment alternatives available to the State for its budget surplus, the Project offers strategic benefits when compared to other uses. As long as the State is confident that it has sufficiently funded any existing deficiencies and is comfortable with its level of risk with respect to any "rainy day" funds, the Project offers the State the ability to create a new source of revenue with limited downside (excluding Firm Transportation Contract exposure). Unlike traditional governmental expenditures, the Project should create a real financial return to the State that should exceed the State's alternative investments. The capital cost of using cash on hand is essentially the foregone earnings on those funds. In this case, the opportunity cost is limited to the alternative investments, which likely would have returns that are much smaller than PipeCo's share of the projected revenues from the Project.

5.3.2. *Issuance of State Bonds*

[37] As noted above, the lenders will need assurance that the State is committed to fund at least $800 million.

[38] Based on their analysis, the Financial Advisors have concluded that other potential uses for the State's budget surplus include the following: (i) funding of existing or expected future deficiencies, such as pension obligations; (ii) funding a "rainy day fund;" (iii) funding a capital improvement plan that offers a financial return without incurring a maintenance liability; (iv) investing in the financial/capital markets (any such investment will be subject to State guidelines and will likely be limited to short-term, low yielding fixed-income investments); (v) funding a capital improvement project that may or may not offer a financial return and incurs a maintenance liability (e.g., funding of the State's parks system); and (vi) creating and funding new ongoing State programs, thus creating an ongoing liability. Note that we understand from the State that, absent avoidance devices, all surplus goes to the Constitutional Budget Reserve.

As an alternative to or in conjunction with direct appropriation of funds from the Legislature, the State could issue bonds to be repaid out of the proceeds of PipeCo's 20% share of the distributions from Alaska LLC. Such bonds might need to be further enhanced by including a moral obligation pledge of the State to replenish a debt service reserve fund for the bonds. Such a reserve fund is generally established as the maximum amount of debt service required in any year (but in some cases is required to cover up to two years). 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 the reserve fund would be drawn upon would be if PipeCo'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. Although it is likely that such a bond issue would be insured as described more fully in Section 5.3.5, the State should consider soliciting underlying ratings for the debt. By virtue of the bond insurance, the debt would carry AAA ratings from all three rating agencies. However, the investor community generally prefers credits with underlying ratings. Pursuing underlying ratings would likely give the State more leverage in their negotiations of the credit charge of the bond insurers. Given the amount of equity-debt the State may raise and the goal of minimizing the State's interest costs, underlying credit ratings may prove essential. Additionally, in the event that municipal bond insurance is not cost-effective or available in sufficient capacity, the debt could be sold solely on the basis of the underlying ratings. Many large institutional investors are substantially limited in the amount of non-rated debt they can own. Restricting the pool of investors will increase the State's borrowing costs. Given that the State will already be required to go to the rating agencies for both the Project debt and to discuss the Project as it relates to the State's credit exposure, requesting equity debt ratings should not add a substantial administrative burden or cost for the State. Any additional burden should be balanced out by reducing the required amount of investor outreach because the investor community will invest partially based on the analyses of the rating agencies. The interest cost savings are almost certain to outweigh the additional cost of obtaining ratings. There are also State credit rating implications associated with any call upon a State moral obligation pledge, and those implications would include all moral obligation debt being included in general fund or tax-supported debt by the credit rating agencies. The authority of PipeCo to issue moral obligation bonds will need to be expressly authorized by the Legislature in the authorizing legislation for PipeCo.

Issuing State bonds in the capital markets provides a more permanent financing solution for the State than does direct appropriation. The Financial Advisors recommend that the State consider financing a portion of PipeCo's equity contribution to the Project with the proceeds of a combination of a revolving loan facility and long-term bonds. Such a revolving loan facility would mature at the target Project completion date and would be replaced with the proceeds of long-term bonds issued at that time and with a maturity date 25-30 years from that date.[39]

The Financial Advisors anticipate that the long-term bonds described above would be structured such that projected net revenues accruing to the State (through PipeCo) from the Project would be more than sufficient to pay debt service on the bonds. In addition, the Financial Advisors expect that the investors in such bonds will want some form of commitment from the State to

[39] The maturity date of the long-term bonds would be set to mirror the projected useful life of the Project.

support the Project revenues should they be insufficient to pay debt service. There are several options, short of a general obligation pledge, that are available to the State for the purpose of providing such support. Please note that each of these options will need to be fully vetted and examined by bond counsel to the State.

- **State Appropriation Credit:** Although not a debt of the State, the State would be legally obligated to make such payments subject to and dependent upon appropriations being made from time to time by the State. We have been advised that to make such an appropriation would have significant consequences for the State's credit rating.

- **State Moral Obligation:** Under a moral obligation, the bonds would be supported by a moral, but not legal, obligation of the State to replenish any debt service reserve fund required by such bonds to the minimum required level should the revenue stream from the Project prove insufficient. We have been advised that a failure to replenish such fund would have significant consequences for the State's credit rating.

- **Other Sources of Credit Support:** The Financial Advisors continue to analyze other potential sources of credit support for State bonds in this context.

In most cases, there is a distinction between State appropriation credit and a State moral obligation that is significant to the market, and investors will charge a premium for bonds issued with only the moral obligation of the State as credit support versus a bond issuance supported with State appropriations.[40]

The amount of annual exposure related to bond financing of the State's portion of equity in the Project is dependent upon several factors: (i) the dollar amount of the bond issuance; (ii) the performance of the Project over time; and (iii) whether or not the State reserves any of its equity returns in good years for funding shortfalls in those years that the Project does not perform as expected.

The schedules on the following page highlight the range of potential exposure the State may face given various return profiles of the Project and various cash contributions for equity.

It should be noted that the amount of the aggregate State credit exposure is dependent not only on the equity component of the Project but also on the end commodity price fluctuations with the shipping contract objectives. The caveat regarding commodity price fluctuations applies until the pipeline is a real and saleable asset (albeit somewhat illiquid) and the State may be able to sell its portion of ownership, retire its obligations, and earn a cash on cash return for its equity.

Table 4 on the next page shows the estimated return on equity for various amounts of debt financed equity.

[40] Please note that this premium is generally very small, but the difference could be greater depending on the structure of the issuance.

Table 4
Estimated Return on Equity Based on Various Amounts of Debt Financed Equity

All Scenarios Assume 30-Year Level Debt Service at 5.00%

Equity Return of 0.00%

Dollar Amount of Bonded Equity	$ 250,000,000	$ 500,000,000	$ 750,000,000	$ 1,000,000,000
Total Debt Service	$ 487,885,763	$ 975,771,526	$ 1,463,657,289	$ 1,951,543,052
Total Equity Return	-	-	-	-
Total Net Exposure	$ (487,885,763)	$ (975,771,526)	$ (1,463,657,289)	$ (1,951,543,052)
Annual Debt Service	$ 16,262,859	$ 32,525,718	$ 48,788,576	$ 65,051,435
Annual Equity Return	-	-	-	-
Annual Net Exposure	$ (16,262,859)	$ (32,525,718)	$ (48,788,576)	$ (65,051,435)
Breakeven Equity Return	1.626%	3.253%	4.879%	6.505%

Equity Return of 5.00%

Dollar Amount of Bonded Equity	$ 250,000,000	$ 500,000,000	$ 750,000,000	$ 1,000,000,000
Total Debt Service	$ 487,885,763	$ 975,771,526	$ 1,463,657,289	$ 1,951,543,052
Total Equity Return	1,500,000,000	1,500,000,000	1,500,000,000	1,500,000,000
Total Net Exposure	$ 1,012,114,237	$ 524,228,474	$ 36,342,711	$ (451,543,052)
Annual Debt Service	$ 16,262,859	$ 32,525,718	$ 48,788,576	$ 65,051,435
Annual Equity Return	50,000,000	50,000,000	50,000,000	50,000,000
Annual Net Exposure	$ 33,737,141	$ 17,474,282	$ 1,211,424	$ (15,051,435)
Breakeven Equity Return	1.626%	3.253%	4.879%	6.505%

Equity Return of 8.00%

Dollar Amount of Bonded Equity	$ 250,000,000	$ 500,000,000	$ 750,000,000	$ 1,000,000,000
Total Debt Service	$ 487,885,763	$ 975,771,526	$ 1,463,657,289	$ 1,951,543,052
Total Equity Return	2,400,000,000	2,400,000,000	2,400,000,000	2,400,000,000
Total Net Exposure	$ 1,912,114,237	$ 1,424,228,474	$ 936,342,711	$ 448,456,948
Annual Debt Service	$ 16,262,859	$ 32,525,718	$ 48,788,576	$ 65,051,435
Annual Equity Return	80,000,000	80,000,000	80,000,000	80,000,000
Annual Net Exposure	$ 63,737,141	$ 47,474,282	$ 31,211,424	$ 14,948,565
Breakeven Equity Return	1.626%	3.253%	4.879%	6.505%

Equity Return of 12.00%

Dollar Amount of Bonded Equity	$ 250,000,000	$ 500,000,000	$ 750,000,000	$ 1,000,000,000
Total Debt Service	$ 487,885,763	$ 975,771,526	$ 1,463,657,289	$ 1,951,543,052
Total Equity Return	3,600,000,000	3,600,000,000	3,600,000,000	3,600,000,000
Total Net Exposure	$ 3,112,114,237	$ 2,624,228,474	$ 2,136,342,711	$ 1,648,456,948
Annual Debt Service	$ 16,262,859	$ 32,525,718	$ 48,788,576	$ 65,051,435
Annual Equity Return	120,000,000	120,000,000	120,000,000	120,000,000
Annual Net Exposure	$ 103,737,141	$ 87,474,282	$ 71,211,424	$ 54,948,565
Breakeven Equity Return	1.626%	3.253%	4.879%	6.505%

5.3.3. *Revolving Loan Facility*

Revolving loan facilities are temporary or short-term financing mechanisms that provide working capital to borrowers and often function as bridge loans (i.e., they are contemplated to be taken out with more permanent financing once a project is constructed). Under a revolving loan facility, the State would negotiate with a syndicate of banks to provide committed funding. The State would have the ability to draw on these funds at any time during the term of the facility. To the extent the State does not draw on the facility, the fees paid to the banks for their commitment to fund a draw are substantially lower than the interest rate charged for funds that have actually been drawn under the facility. Benefits of a revolving loan facility often include abbreviated loan documents, accelerated market access and the ability to negotiate flexible terms otherwise not found in traditional capital market transactions. As noted above, the Financial Advisors recommend using a revolving loan facility as a core component of the overall financing of PipeCo's equity contribution obligations.

5.3.4. *Equity Contribution or Loan Proceeds from the Permanent Fund*

As more fully discussed in Section 7, the Permanent Fund could possibly play a role in the Project as either an equity investor in Alaska LLC or as a lender (most likely to PipeCo). In either such role, the Permanent Fund could provide a substantial source of funds for the Project. Unfortunately, tapping this source of State funds is not nearly as straightforward as appropriating funds from the State's budget surplus and may be even more complicated than seeking debt financing in the market. The benefit of Permanent Fund participation in the Project is that it would reduce the financial burden on the State resulting from the State's involvement in the Project. As an equity investor, any contribution made from the Permanent Fund would result in a dollar-for-dollar reduction of PipeCo's equity in Alaska LLC and would thus reduce the State's equity contribution obligations. As a lender, the Permanent Fund Corporation would lend to PipeCo (such loans would most likely be structured as a revolving loan facility) in order to finance PipeCo's equity contributions.

We have been advised by counsel to the State that the Permanent Fund Corporation is subject to both administrative policy bylaws and legislative statutes governing its investment strategies. In addition, it is possible that certain laws and regulations governing the Permanent Fund may need to be amended to allow for the Permanent Fund Corporation to invest in Alaska LLC. Initial discussions regarding how to best navigate these restrictions and whether to implement any changes necessary to permit the Permanent Fund Corporation to invest in Alaska LLC are ongoing.

We have been advised by counsel to the State that Section 27.13.120(c) of Article I of Alaska State Law regarding investment of the Permanent Fund states that "the Board shall maintain a reasonable diversification among investments unless under the circumstances it is clearly prudent not to do so." Depending on the magnitude and nature of the Permanent Fund's involvement in the Project, substantial portfolio risk adjustments may be necessary and prudent. All modifications to the Permanent Fund's investment guidelines require legislative review and thus take time, thereby making an investment from the Permanent Fund somewhat less attractive than a direct appropriation of funds by the State, and potentially less reliable than a bank financing. While the Financial Advisors' analysis thus far has led them to positive conclusions on the points set forth above, there are several additional issues that could impede using the Permanent Fund as a source of funds or credit support for the Project. First, if the tariffs applicable to the Firm Transportation Contracts do not provide a sufficiently high return on equity, then the restrictions on the Permanent Fund's permitted investments may prevent it from being involved in the Project. Second, if, as an equity investor, the Permanent Fund Corporation would be required to provide completion support, then such investment may be outside the scope of what Permanent Fund legislation permits. Third, to the extent that using the Permanent Fund as a source of funds for the Project could create negative tax implications for the Permanent Fund, then such an investment in Alaska LLC may be prohibited. Finally, if the administrative burdens associated with arranging for the Permanent Fund's involvement in the Project are estimated to be too costly or time consuming, then the Permanent Fund Corporation may, either as a practical matter or because it is required to do so, elect not to participate in the Project.

5.3.5. *Role of Municipal Bond Insurance*

To the extent the State elects to pursue a bond financing to provide long-term funds for PipeCo's equity contribution obligations, the Financial Advisors recommend that the State also seek to insure such bonds. The use of bond insurance has increased over time and is now widespread in the taxable bond marketplace. In 2005, roughly 36.5% of all taxable bond issues exceeding $100 million utilized bond insurance. Furthermore, taxable bond issues exceeding $500 million utilized bond insurance 25.1% of the time.

Just as the DOE Guarantees would allow lenders to look to the credit of the Federal government rather than Alaska LLC, bond insurance would enable the State to issue bonds based on the bond insurer's rating, which in this case will be higher than the stand-alone rating of the State. Such enhanced credit rating and the participation of the bond insurers in the bond financing will generate multiple benefits for the State as issuer. The three primary considerations that must be weighed when deciding whether to use bond insurance are as follows: (i) the degree to which it will increase cost effectiveness; (ii) the degree to which other benefits will be offset by restricting future financing flexibility due to required insurer indenture provisions; and (iii) the degree to which the credit enhancement provided by bond insurance will broaden the range of potential investors and thereby improve market access. Another factor to consider when weighing whether to use bond insurance is that, although it provides investors with added security that, despite what may happen to the issuer, they will receive on-time repayment, it does not eliminate the issuer's obligations. Bond insurance merely transfers the issuer's obligation from the bondholder to the insurance provider. In the event the issuer misses a bond payment, the insurance company would step in place of the issuer and continue the timely repayment of the debt. Generally, the guarantee of the insurance company is irrevocable, lasts for the entire life of the associated debt, and does not force an acceleration of the debt. Although the terms of the issuer's commitment to the insurance company will depend on the specific parameters of the commitment, the insurer will undoubtedly hold a secondary lien on the security for the debt and will seek to be repaid by the issuer for any payments it makes to the investors.

As part of the process of considering bond insurance, the Financial Advisors also recommend that the State contact potential insurers at an early stage of the Project. Such early engagement will create an open dialogue between the State and the insurers that will continue as the Project progresses. The information garnered from these discussions will help the State determine the most cost effective approach to insuring its bond financing at the time any such financing occurs.

<u>Cost Effectiveness</u>

A key factor for the State in determining the appropriateness of bond insurance is its cost effectiveness. Savings are derived from the lower interest rate usually obtained when issuing bonds guaranteed by bond insurance. For example, an A-rated issuer can issue 30-year, fixed-rate bonds at about 4.97%, compared to a rate of approximately 4.72% if it issues insured ("Aaa/AAA" rated) bonds. In return for this lower yield, the issuer must pay a one-time upfront premium to the insurance company to guarantee payment of principal and interest over the life of the bonds. In order to determine if this one-time upfront premium is offset by such yield reduction (i.e., cost effective), the Financial Advisors would compare the debt service generated under the uninsured scenario versus the insured scenario. To the extent debt service is lower based on an insured scale, insurance is said to be cost effective, and vice versa. If an insured bond is refunded, there is no credit back to the borrower for any "unused" bond insurance premium, nor is there a refund of any portion of the premium.

<u>Future Financing Flexibility</u>

Bond insurers will generally request significantly more restrictive financial and security covenants on a borrower than what is required for issuing stand-alone bonds. Financial covenants typically required by bond insurers include: (i) annual tests for debt service coverage; (ii) additional debt tests based upon cash flow and balance sheet ratios; and (iii) a more narrow scope of eligible investment securities for bond proceeds. These additional, sometimes onerous, conditions may, and in most cases would, limit the State's ability to issue additional bonds with the same level of seniority and lien priority as the original bonds in order to raise funds for the Project in the future.

<u>Market Access</u>

Increasing the investor base for a project of this size and scope will only strengthen the pricing of any underwriting. One way to assure the widest investor base is to provide a wide array of financial products, such as insured bonds. There are certain funds that are restricted from purchasing municipal bonds unless they are insured. As such, the Financial Advisors recommend that, at the very least, a portion of any offering be insured to initially attract the most interest in any offering. The State can always determine on the day of pricing whether or not to include the insured component in the final structure.

At this time it is the Financial Advisors' belief that municipal bond insurance will be beneficial for the majority of any long-term bond financing of the State's interest in Alaska LLC.

5.3.6. ***Choosing Between a Competitive and Negotiated Bond Sale***

It is the Financial Advisors' belief that due to the complexity, unprecedented size and scope of this Project, the State's need to continually negotiate with the Producers, and the Project's exceptionally long lead time, that any municipal underwriting taken on by the State for this Project should be completed on a negotiated basis.

Since January 1, 1991, there have been 43 taxable municipal issues totaling in excess of $42 billion. Of these 43 issues, only two totaling $1.2 billion (2.86%) have been issued on a competitive basis.

The discussion below focuses on the general arguments of competitive versus negotiated financings.

There is a long-standing debate among local government issuers, underwriters and financial advisors in the municipal securities market over the relative merits of negotiated versus competitive sales for both bonds and swaps. The appropriateness of the method of sale is specifically tied to the needs of a particular financing or structure, as described by the following factors.

Negotiated Financings Allow Flexibility to Tailor Bond Issue/Swap Structure as Markets Change

Over the past several years, flexibility in structuring a bond issue or swap to meet investor demand has been crucial in ensuring that the transaction is priced at the lowest possible rates. A negotiated bond transaction allows the various structural components of an issue to be developed or modified to suit investors' demands given changes in market conditions. Issue structure—such as maturities, types of securities (e.g., serials, terms, par/discount or premium bonds), split or multiple coupons per maturity, coupon levels, takedowns and redemption features—can be adjusted up to the end of a negotiated pricing. Similarly, a negotiated swap allows the State and its financing team an opportunity to work closely together to react to any new facts regarding its circumstances and the market, and to respond to these facts by fine-tuning the structure of the proposed swap transaction. By not forcing the components of the structure to be locked-in prior to the sale date, a negotiated bond or swap transaction would allow an issuer to take advantage of improving market conditions or to respond effectively to a sudden movement in the market.

Negotiated Financings Allow Flexibility to Time Bond Issues/Swaps to Respond to Market Conditions

Today's market demonstrates a great deal of intra-day volatility as it reacts quickly to economic data, Federal Reserve Board policy, rumors and other external factors. A negotiated transaction allows the issuer to manage market volatility. In a negotiated bond sale or swap, the State has the flexibility to postpone or accelerate both the date and the time of the sale. If the market deteriorates during a negotiated pricing and the financial parameters of the issue are no longer acceptable to the State, the sale of the bonds or the execution of a swap can be delayed until market conditions improve, or it can be rejected entirely. A competitive sale has a defined bid time that does not provide the State any flexibility in changing the time of pricing. In difficult markets, liquidity in the competitive bond market tends to diminish, resulting in fewer bidders, wider spreads in pricing and more limited distribution. These difficult transactions also can taint the pricings of subsequent transactions. For swaps, the ability to price discreetly and on short notice in a negotiated transaction is an especially important factor and allows for careful monitoring and timing of the market.

High Degree of Price Transparency in the Bond and Swap Markets

In the past, some issuers have favored competitive bond and swap bids because of concerns about getting a fair price. In today's market, municipal market data for both bonds and swaps are now widely available through sources such as Bloomberg and Thomson Financial Services as well as real-time trading information, bringing a high degree of pricing transparency to the market. Swap pricing is particularly transparent with one mid-market swap yield curve. Moreover, the State has financial advisors who are well-qualified to provide price assurance on bond and derivative transactions.[41]

[41] Please note that the points in this paragraph do not apply to bonds issued in connection with project financings.

Negotiated Bond Financings Create Investor Demand via Pre-Sale Marketing Efforts

A negotiated bond sale provides an opportunity to promote an issue and to stimulate investor demand, resulting in lower borrowing costs. By contrast, with a competitive bid, prospective investors are not actively involved in any pre-sale marketing program (primarily because a firm cannot market bonds it is not sure it will own) and frequently appear disinterested in the bonds at the initial offering in hopes of buying them more cheaply in the secondary market. In a competitive sale process, the issuer has no means for retail priority and no effective means of targeting the distribution of bonds. By appointing an underwriting team for a negotiated bond sale, the issuer can benefit from the underwriting team pre-marketing the upcoming issuance to both national and local investors.

A Negotiated Management Group Focuses on Secondary Markets

Secondary market placement (i.e., the maintenance of a liquid resale market for securities) will enhance the success of subsequent bond issues by minimizing any "overhang" of bonds in the market. In a negotiated sale, the management group will provide support for State-issued bonds in the secondary market. In a competitive sale, bidders have less incentive for maintaining a liquid secondary market.

Negotiated Financings Allow for Greater Participation by Local Underwriters

The negotiated bond sale process would allow the State to broaden local firms' participation because it gives the State an opportunity to set goals for the distribution of the bonds.

A Negotiated Bond Sale or Swap Promotes Stronger Interaction with and Performance by Wall Street Firms

Issuers that pursue negotiated bond and swap sales benefit from consistent and ongoing service from the major Wall Street firms. The appointment of a negotiated sale is a mechanism for many issuers to motivate and compensate firms for good ideas and high-quality service. Firms focus their work efforts and ideas on negotiated issuers. In addition, issuers who regularly price negotiated sales will benefit from aggressively priced bids on potential competitive sales.

A negotiated sale has the advantages of cultivating investors on an ongoing basis, ensuring strong secondary market performance, providing a broad market at the time of issuance, and encouraging better service from the investment banking community. Finally, the negotiated sale can be an effective method of dealing with volatile markets or periods of uncertainty, whereas a competitive sale has only one mechanism for prospective underwriters to address market volatility—cushioning (or weakening) the bid.

5.4 *Construction Overruns*

Any project of this size, complexity and duration will almost certainly face unbudgeted cost overruns at some point.[42] In the case of this Project, the magnitude of these cost overruns could be very significant (i.e., billions of dollars) and, therefore, the consequences and risks associated

[42] Please note that certain cost overruns will be included in the construction budget. Specifically, since the lenders also understand that cost overruns are likely to be unavoidable, they will probably include some cushion in their loans (typically 10%) to allow for such cost overruns. Please also note that if cost overruns exceed such 10% cushion, such increase could trigger a default under the construction financing agreements.

with such cost overruns are central to the Project. As such, any Finance Plan must seriously consider and manage the potential for cost overruns.

The myriad sources of potential cost overruns are too many to number and could range from higher than expected commodity (e.g., steel) prices to labor problems, foul weather, regulatory or litigation-related delays, and a variety of other factors and events.

The consequences of cost overruns are also multifold. The most obvious effect of cost overruns is that additional money will need to be allocated to the Project in order to achieve completion. As with the initial construction financing, the sources of such additional funding will be either debt or equity or a combination thereof, and whether debt is incurred by Alaska LLC or some or all of the Members as borrower(s).

Since cost overruns are likely to occur, the Financial Advisors continue to analyze the benefits of seeking cost overrun debt financing concurrently with base construction cost debt financing. Though there are certain costs associated with seeking cost overrun debt financing in advance of when it is needed, by seeking debt financing when cost overruns are still contingent liabilities, the State may be able to negotiate better terms and pricing.[43] Even under the best circumstances, however, it is unlikely that the terms of cost overrun debt financing will be as favorable as the terms of base construction cost financing. Specifically, cost overrun lenders will likely require a higher equity contribution (possibly as much as 40% of total cost overruns) and pricing may be increased to reflect a higher risk profile. The utilization of DOE Guarantees as a credit enhancement could improve the terms of such cost overrun debt financing, and the engagement of the Permanent Fund as a cost overrun lender to PipeCo could also substantially reduce the risk of PipeCo obtaining unfavorable terms for cost overrun debt financing undertaken in a Member-level Financing.

As noted above, even if cost overrun debt financing is incurred, some portion of cost overruns will have to be funded with equity. If cost overruns are relatively small, then such equity funding hopefully will not cause any problems for PipeCo. However, if cost overruns are large, then PipeCo may not be able to meet cash calls and would be subject to remedies imposed by the non-defaulting Members as described above.

6. Utilization of DOE Guarantees

While the lenders' analysis of the proposed financing of the Project would ordinarily be keyed solely to the Project's economics (including shipper credit strength) and then priced accordingly, a major credit enhancement available to the State and the Producers is to utilize the DOE Guarantees and to have the Federal government guarantee Alaska LLC's debt. In order to encourage development of the Project, the U.S. Congress passed ANGPA on October 13, 2004. ANGPA makes the DOE Guarantees available for up to $18 billion or 80% of the cost of the Project, whichever is less, and delegates administration of the Federal Loan Guarantee Program

[43] If the State waits to procure debt financing for cost overruns until cost overruns are imminent or have already occurred, then the State would be choosing between failing to fund cash calls (and potentially diluting or forfeiting its equity in the Project as a result) or accepting less than perfect debt financing terms and pricing.

to the Department of Energy. The specifics of the program are still being developed by the Department of Energy.

While provision of the DOE Guarantees would not relieve Alaska LLC of its responsibility to pay all interest and principal on borrowed funds, the DOE Guarantees will provide Alaska LLC's lenders, or the buyers of its bonds, with the assurance that the Federal government would make such lenders or bondholders whole if Alaska LLC failed to meet its payment obligations. Should this guarantee be called upon, the Federal government will likely then require the borrower to make good on its borrowing commitment as well as require providers of completion support to make good on their commitments. 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 among the State, the Producers and the Department of Energy. However, both the State and the Producers 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 Producers are uncertain whether the DOE Guarantees would be utilized in a financing of the Project for only the first $18 billion of debt incurred to construct the Project or, instead, reserved to cover debt which may be needed to cover cost overruns (or utilized in another manner that may be more cost-efficient for the Project and State). In any event, application of the DOE Guarantees to Alaska LLC's debt will probably lower the cost of borrowing with respect to such debt by approximately 50 to 100 basis points, depending on market conditions.

One of the reasons the Financial Advisors recommend pursuing an LLC Financing is that we have been advised that there is certainty that the project-level company (e.g., Alaska LLC) could utilize the DOE Guarantees. We have been advised that there is some uncertainty as to whether the Members could benefit directly from DOE Guarantees. Regardless of whether the DOE Guarantees are used by Alaska LLC or by the individual Members, the Financial Advisors suggest that the State and the Producers explore creative uses for the DOE Guarantees other than applying them just to the initial construction loan. For example, there may be significant value associated with using the DOE Guarantees in connection with seeking debt financing for cost overruns. Specifically, because the DOE Guarantees act as credit enhancements, their value (e.g., lowering the cost of borrowing) will be greater to the borrower when the borrower's credit is more depressed (e.g., in a cost overrun scenario).

The Financial Advisors and the State will continue discussing amongst themselves, and with the Producers, how to maximize the value of using the DOE Guarantees, including the application of such guarantees to cost overrun facilities rather than the initial construction facility.

7. Role of Permanent Fund in the Project

The State and the Financial Advisors are currently analyzing whether the Permanent Fund could act as a source of funds for the Project in a way that would be consistent with the State's goals and would meet the Permanent Fund Corporation's mandate. The possibilities for Permanent Fund Corporation involvement include: (i) making an equity investment in either PipeCo or Alaska LLC and/or (ii) acting as a lender to PipeCo.

We have been advised by counsel to the State that, to the extent that such an investment is consistent with the Permanent Fund Corporation'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,"[44] the Permanent Fund Corporation could elect to participate in the Project by investing in the Alaska LLC or PipeCo.[45] The State and the Producers expect the Project to yield a competitive rate of return on equity, with initial return on investment in 2016. Therefore, the State and its counsel do not expect the Permanent Fund Corporation to evaluate the Project as if it were an economic development project.[46] We have been told by the State and its counsel that the Permanent Fund Corporation is not necessarily prohibited from investing in the Project, and the Permanent Fund's involvement will be viewed and analyzed by its Board of Trustees only from the perspective of a prudent financial investment.

From the perspective of the Permanent Fund Corporation, the benefits of investing in the Project with equity are that the Project has strong fundamentals and is projected to return robust dividends to equity investors over the next several decades. Thus, on its face such an investment would appear to comply with the rules governing investment of the Permanent Fund. With respect to the revenue stream that would be diverted to the Permanent Fund as an equity owner, the Financial Advisors note that the limitations on investments that may be made with the Permanent Fund may mean that such revenue will not be available for general State needs. Benefits to the State of selling an equity share in Alaska LLC to the Permanent Fund Corporation include the fact that with the Permanent Fund Corporation participating in the Project, the State would be able to share the burden of any construction costs, including costs overruns.

As a lender for cost overruns (or base case construction costs), the Permanent Fund would have a lower rate of return than it would as an equity investor, but such return would be fixed and less risky because it would be paid before the Producer Subs are paid. From the State's perspective, having the Permanent Fund Corporation as a participant in the Project would help PipeCo meet cash calls for Project costs (particularly in the case of cost overruns) without diminishing its equity stake in the Project.

The State believes that an investment in the Project will receive appropriate consideration by the Permanent Fund Corporation. 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 Permanent Fund Corporation's Board of Trustees is the fiduciary for all Permanent Fund investments and, with the assistance of its staff and others, directs the allocation of funds to asset classes utilizing

[44] Alaska Permanent Fund Corporation. (2001). An Alaskan's Guide to the Permanent Fund, page 45. Juneau, Alaska: Alaska Permanent Fund Corporation.

[45] The investment analysis will differ depending on what role, if any, the Permanent Fund Corporation takes. For example, as a lender, the Permanent Fund Corporation would likely earn a lower return on investment (in the form of interest paid on its loan) than it would as an equity investor, but it would also have a lower level of risk in a number of respects (including priority of payment for scheduled payments of interest and principal over equity distributions).

[46] 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.

modern investment portfolio theory. If the Permanent Fund Corporation were to invest in the Project, the State anticipates that the Permanent Fund Corporation 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. We understand that 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.

The Permanent Fund is divided by the State’s Constitution into two parts: the principal and the undistributed cash earnings account, known as the “Realized Earnings Account.” The Trustees of the Permanent Fund are permitted to invest both the principal and the earnings of the Permanent Fund in investments that meet the “prudent investor” threshold. The Legislature may appropriate only from the Realized Earnings Account. The principal balance of the Permanent Fund 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 inflation-proof the Permanent Fund principal. Any decision by the Permanent Fund to invest in the Project (including an equity investment in PipeCo or Alaska LLC) will thus likely entail an investment of the Permanent Fund’s principal. Table 5 displays the fiscal year end value of the Realized Earning Account and the Permanent Fund’s principal for 2001-2005 and projected value for 2006-2011.

Table 5
Permanent Fund Corporation
Realized Earnings Account and Principal

Year	Type	Realized Earnings Account ($ in millions)	Principal ($ in millions)
2001	Realized	2,384	21,047
2002	Realized	1,136	21,884
2003	Realized	100	22,988
2004	Realized	859	23,526
2005	Realized	1,440	24,647
2006	Projected	1,914	26,092
2007	Projected	2,451	27,293
2008	Projected	2,902	28,439
2009	Projected	3,367	29,405
2010	Projected	3,857	30,388
2011	Projected	4,384	31,383

Table 6 includes projections of the value of additional royalties that would go to the Permanent Fund under a range of gas prices during the first 10 years of Project operations.

Table 6

Potential Revenues to the 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: Alaska Department of Revenue.
Note: Assumes 28% royalty contribution rate; see Footnote 55.[47]

[47] We have been advised by the State that, prior to 2004, oil and gas from leases issued after 1979 had a Permanent Fund contribution rate of 50% of royalties, while all older leases contributed at 25%. In 2004, legislation was changed so that all leases contributed at 25%. 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%. About 2/3 of Pt. Thomson leases are pre-1979, and 1/3 are post-1979. The Permanent Fund Corporation estimates that so far the provision has reduced dividends by $1.85. It was 52 cents after 2004. The Permanent Fund Corporation does not have an estimate of when the cumulative reduction will reach $20.00. The assumption is made that $20.00 is reached by 2016, which results in a weighted average contribution rate of 28%.

Glossary of Defined Terms

Page

Appendix G

Executive Summary of PFC Energy report: Assessment of the Alaska Gasline Port Authority LNG Project

Assessment of The Alaska Gasline Port Authority LNG Project

Prepared for The Alaska Department of Revenue
March 17, 2006

Final Report

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2. Executive Summary

PFC Energy's analysis of the AGPA project indicates that the project does not provide a superior netback value for monetizing Alaska's North Slope gas when compared to a natural gas pipeline to the Chicago area.

Below is summarized the key conclusions from the principal elements of the analysis conducted by PFC Energy.

West Coast Terminal Evaluation

- 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 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.
- The Northern Star terminal is also advanced in the regulatory process, and is well into the FERC pre-filing process. Its prospects for receiving environmental approvals are good, but not likely because of the volume of dredging needed by the project and concerns related to the release by dredging of toxic materials from sediments to the water column that then pollute fish consumed commercially and by Native Americans. Moreover the overall project's likelihood of receiving financing and beginning construction are poor because of the project's location and the limited market in the US northwest yield a significant risk that it will see seasonal variations in utilization or even be made redundant by rising Rockies gas production and other better positioned receiving terminals.
- PFC Energy's review of Clearwater Port shows that it has made little headway in the regulatory process for over a year and a half, and lags another nearby project considerably. Given the challenge of securing all regulatory approvals offshore from such a populated area and the progress of a direct competitor, PFC Energy considers the construction and operation of this project in the next ten years as unlikely.
- Port Penguin is to all intents and purposes a defunct project. Conceived by ChevronTexaco, the California Energy commission lists the project as terminated on its website according to the August LNG project update. PFC Energy considers the likelihood of construction and operation of this project in the next ten years as negligible.
- SES is well advanced in the regulatory process, but the California Energy Commission, the California State Lands Commission and the City of Long Beach have raised a number of similar objections relating the methodology of the threat assessment that, if applied, would make if very difficult to show that the project presents an acceptable level of risk to surrounding areas. Though PFC Energy expects that FERC will not incorporate these methodological assumptions into their assessment of the

project, we expect that the state will oppose the project though other means, making the project's odds of construction in the next ten years poor.

West Coast Gas Marketing Issues

- The most appropriate liquid market point determinations were made based on proximity to the terminal, and estimated the levelized costs of new facilities needed to move the regasified LNG to locations where these prices could be realized

LPG Marketing Assessment

- The cost of shipping propane and butane to Japan via long term charter or newbuild VLGC to be $1.71/barrel.
- PFC Energy's estimations of Chicago area LPG prices indicate a Chicago market premium of $1.50/barrel over Japan, and that this differential would be unchanged if the AGPA project went forward, but would decline to $1/barrel if the Chicago pipeline project went forward.

Cost Estimate Review

- PFC Energy's estimates of the AGPA project's costs were 5%-8% higher than the estimates generated by Bechtel, but for the purpose of determining project economics, the Bechtel costs were used.
- PFC Energy estimates the cost of shipping LNG via Jones Act-compliant tankers to be 54% above those of tankers not required to comply with the Jones Act, due primarily to higher construction costs and being subject to US taxes. PFC Energy believes that deliveries to Kitimat would also be subject to Jones Act requirements because
    - Canada in general and British Columbia in particular is already an exporter of natural gas to the United States, and some portion of this gas will ultimately be delivered to the United States
    - The natural gas will not be substantially processed or transformed in Canada; Kitimat's developers planned to extract LPGs from received LNG at the receiving terminal, but the AGPA project is not likely to produce multiple specifications of LNG for different terminals without incurring a thermal efficiency penalty in the liquefaction facility

Alaska Netback Comparison

- The netbacks were calculated based on levelized project cost estimates for the AGPA project and using an estimate for the Alaska-Chicago pipeline tariff provided by the Alaska Department of Revenue as well as PFC Energy's estimate of the average price realized by both projects:
    - $5.93/MMBtu for the AGPA project
    - $6.54/MMBtu for the Chicago pipeline project
- The AGPA project offers a significantly lower netback to North Slope gas than the Chicago pipeline project; PFC Energy estimates a netback to North Slope gas via the Chicago pipeline of $4.69/MMBtu, as opposed to $3.17/MMBtu for the AGPA project based on public domain asset cost estimates where available (i.e. AGPA for liquefaction facilities, LNG terminal project sponsors for

terminal costs, etc.). Using PFC Energy's internally generated asset cost estimates for the AGPA project, the difference widens, with the AGPA netback dropping to $3.05/MMBtu.

- The average price received by the AGPA project for gas sold into the West Coast is an average of $0.61/MMBtu lower than that realized by the Chicago pipeline project, due primarily to regional gas price differentials and the greater average distance of AGPA sales form major consuming centers relative to the Chicago pipeline project.
- The breakeven cost for the Chicago pipeline project to transport gas (net of LPG revenue) is $1.85/MMBtu. A levelized tariff of $2.76 would be needed for the AGPA project based on public domain costs, and $2.88 based on PFC Energy's asset cost estimates. Either way, the Chicago pipeline project has a decisive cost advantage.
- PFC Energy's assumption that the AGPA project will not be able to realize a premium for ethane in the rich gas stream has an adverse impact on this project's projected economics, but is not a decisive factor.

Appendix H

Executive Summary of Information Insights Report on Economic, Fiscal, and Workforce Impacts of Alaska Natural Gas Projects

Economic, Fiscal and Workforce Impacts of Alaska Natural Gas Projects

EXECUTIVE SUMMARY

MAY 5, 2006

Prepared for

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Economic, Fiscal and Workforce Impacts of Alaska Natural Gas Projects

EXECUTIVE SUMMARY MAY 5, 2006

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Executive Summary

INTRODUCTION

Alaska is in a good position to benefit from oil and gas industry strengths during the present period of record petroleum prices and profits. The State of Alaska has focused significant efforts on reaching an agreement to build a natural gas pipeline for transporting Alaska North Slope (ANS) gas to world markets.

The Alaska Department of Revenue (DOR) has asked Information Insights to analyze the economic, fiscal and workforce impacts of an Alaska natural gas project with a zero year, five year and ten year delay. Our analysis appears in two parts:

- An impact analysis of the gas pipeline proposal by the major North Slope producers [BP Exploration (Alaska), ConocoPhillips Alaska, Inc., and ExxonMobil Alaska Production, Inc.[1]] using a set of baseline assumptions provided by the department.
- A comparison of the impacts of three different scenarios for bringing Alaska gas to market based on our best estimates of costs and prices. The scenarios are based on proposals from the sponsor group and the Alaska Gasline Port Authority, but project assumptions have been adjusted to produce the best "apples to apples" comparison of all projects. The scenarios are:

    i. A 4.5 bcf/d (billion cubic feet per day) gas pipeline that parallels the Trans Alaska Pipeline to Delta Junction, Alaska, and then follows the Alaska Highway to Alberta, Canada. A 0.25 bcf/d spurline to Southcentral Alaska supplies in-state gas needs.

    ii. 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. A 0.25 bcf/d spurline supplies gas for in-state use to Southcentral Alaska.

    iii. 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.. A 0.25 bcf/d Southcentral spurline from the Valdez line serves in-state needs.

To evaluate the impacts to the economy and employment in the State of Alaska for the baseline case and each of the scenarios, Information Insights created four economic models in Microsoft Excel, using in part economic data generated from IMPLAN economic impact modeling software. Our models calculate:

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[1] Acting together as the Sponsor Group, the producers submitted a single application to the State of Alaska under the Stranded Gas Development Act (SGDA). The companies are referred to jointly in this study as the producers or the sponsor group.

- Fiscal impacts to the State of Alaska and its municipalities in annual revenues, and the net present value (NPV) of these revenues;
- Economic output, or contribution to gross state product, from the project, including effects of pipeline construction and operation, from state and local government spending of new oil and gas revenues, and from personal spending of Alaska Permanent Fund deposits generated from the project;
- The number of jobs created in the private and public sectors by the project and new economic activity brought about by the project;
- The effects of a delay in project start on these outcomes.

PART I. BASELINE ANALYSIS OF THE SPONSOR GROUP PROJECT

We modeled the fiscal, economic and workforce impacts of an AlCan pipline project under the following baseline assumptions provided by the Department of Revenue.

Figure 1: Baseline assumptions for sponsor group project

Expected natural gas price, Chicago market	\$5.50/mmBtu
Expected oil equivalent price	\$33.00/Bbl
Year in which actual construction is expect to start	2011
Year in which the gas first flows	2015
Year in which last gas flows through the pipeline	2050

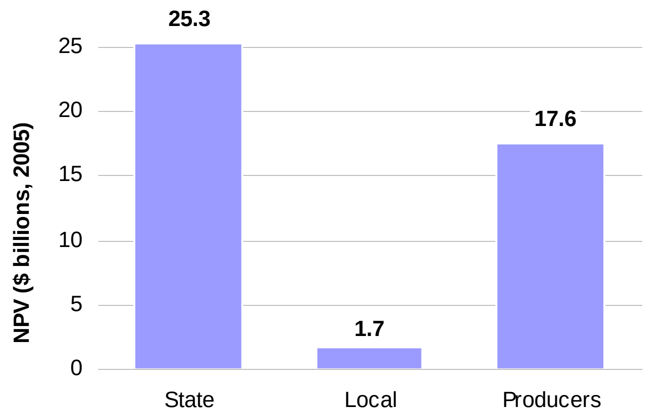
Note: All prices in real 2005 dollars

With a Chicago gas price of \$5.50/mmBtu, we calculate a well head price of \$3.43/mmBtu and a total pipeline tariff to be \$2.07/mmBtu in 2005 dollars.

Based on these assumptions, our models show a net present value (NPV) of earnings to state and local governments of \$27.0 billion over the life of the project[2]. The net present value of the project to the producers will be roughly \$17.6 billion through 2050. Project revenues are expressed in real terms in 2005 dollars and include the effects of gains and losses in North Slope oil production due to a gas project, as well as revenues from the sale of natural gas and natural gas liquids. Our models use a 5 percent discount rate to calculate the present value of government revenue and a discount rate of 10 percent for private sector earnings.

[2] This report uses the 45-year period from 2006 through 2050 as the basis for all economic, fiscal and workforce projections.

Figure 2: Net present value of project revenues, 2010-2050



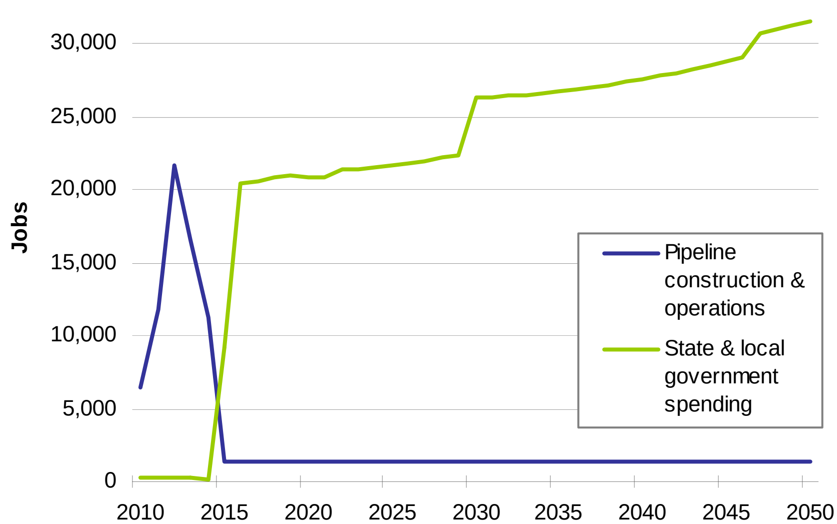
Note: Producers' NPV at 10%, government NPV at 5%

Assuming 25 percent of state royalties are placed into the Alaska Permanent Fund, annual earnings to the fund are the 7.6 percent projected by the Alaska Permanent Fund Corporation, and payouts of permanent fund dividends under current law, the project would result in a $28 billion increase to the Permanent Fund over the project's life.

The number of project-related jobs totals 68,000 job-years during construction. After construction, we expect an average of 1,300 jobs per year operating the pipeline and related facilities. State and local spending of project-related revenues will create an additional 901,000 jobs over the life of the project, for a total of just under 1 million jobs for all years from all sources.

Figure 3 shows the annual workforce impact from a gas pipeline using the baseline assumptions. Each job represents the equivalent of one full or part-time job created through direct, indirect and induced employment impacts.

Figure 3: Annual workforce impact of gas pipeline using baseline assumptions



Note: Direct, indirect, and induced full and part-time jobs

The following table summarizes the results of the sponsor group project on Alaska's economy, using baseline assumptions:

Figure 4: Impacts of sponsor group project using baseline assumptions

Well head and Tariff	
Well head natural gas price	$3.43/mmBtu
Total pipeline tariff	$2.07/mmBtu
Economic and Fiscal Impacts	
NPV (at 5%) to local governments ($ billions, 2005)	$1.7
NPV (at 5%) to state government ($ billions, 2005)	$25.3
NPV (at 10%) to producers ($ billions, 2005)	$17.6
Total NPV ($ billions, 2005) [1]	$44.6
Total construction spending ($ billions, 2005) [2]	$21.0
Estimated construction spending in Alaska ($ billions, 2005) [2]	$11.0
Ave. annual pipeline operations expenses ($ billions, 2005) [2]	$0.3
Ave. annual spending of gas revenues by state and local governments ($billions, 2005) [2]	$1.6
Total post-construction spending ($billions, 2005)[2]	$69.1
Cumulative effect on Alaska Permanent Fund balance ($ billions, 2005)[3]	$28.0
Workforce Impacts	
Total project-related jobs during constructionj[4]	68,000
Ave. annual project-related jobs during construction[4]	14,000
Total jobs from pipeline operations[4]	48,000
Average per year pipeline operations jobs[4]	1,300
Total jobs generated by state and local spending[4]	901,000
Ave. annual jobs generated by state and local spending[4]	25,000
Total jobs all sources all years[4]	1,016,000

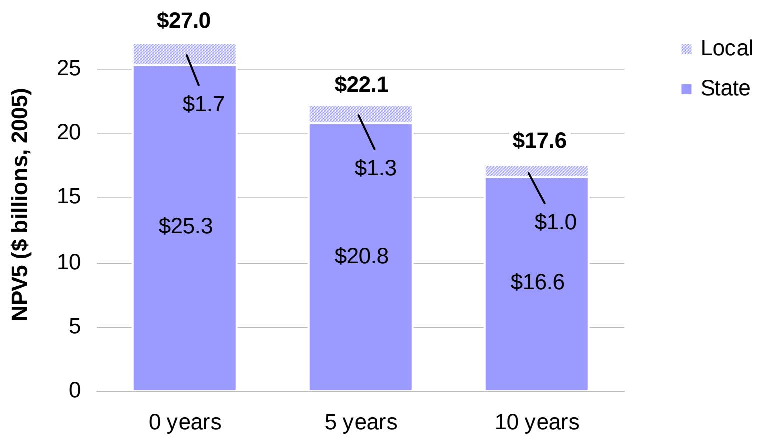
Notes:

1) 10 percent discount rate for producer earnings; 5 percent discount rate for state and local revenues.
2) Cumulative deposits and earnings less dividends, adjusted for inflation, based on 7.6 percent return and current law for dividends.
3) Direct spending in real 2005 dollars.
4) Includes direct, indirect and induced jobs, where 1 job is a full or part-time job over the course of a single year.

Impact of Delay

If the pipeline is delayed, the net present value of the project to state and local goverments will be reduced by nearly one billion dollars per year in real terms. The cumulative effect of delay on state and local revenues is shown in the figure below:

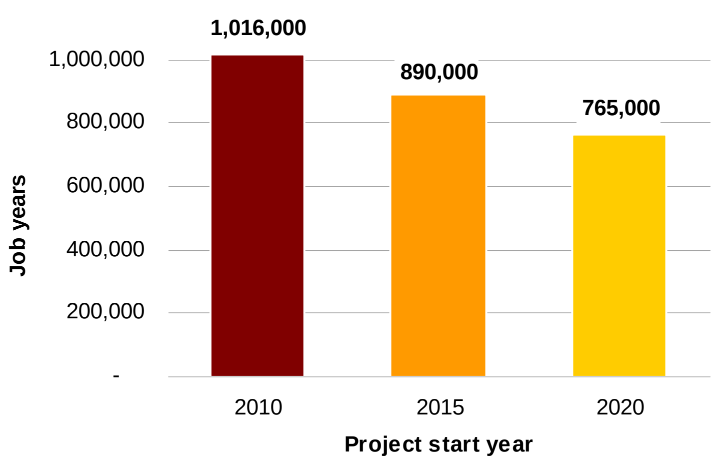
Figure 5: Impact of delay on state and local revenues



Note: NPV at 5%

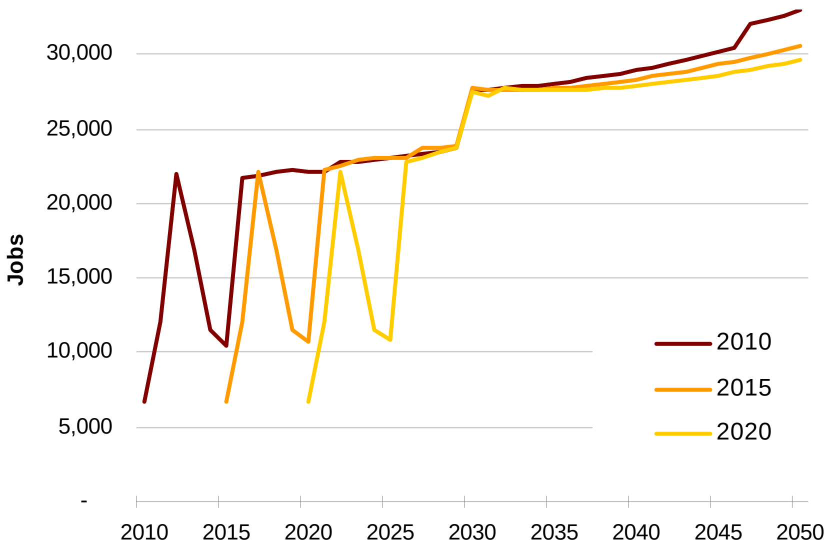
Reduced government earnings will in turn have impacts on state and local spending, Permanent Fund earnings, and job creation. The effect on total jobs from all sources from now through 2050 is substantial, with a loss of 126,000 jobs (12 percent) from five years of delay, and 250,000 jobs (25 percent) from ten years delay, as shown in Figure 7.

Figure 6: Impact of delay on total jobs from all sources



Note: Jobs shown include direct, indirect, and induced jobs, where one job is full or part-time job over the course of one year.

Figure 7: Impact of delay on annual jobs from all sources



Note: Jobs shown include direct, indirect, and induced jobs, where one job is full or part-time job over the course of one year.

In addition, a delay in the start of a project could result in a significant change in resident hire rates due to the aging of Alaska's skilled construction workforce. Nearly 30 percent of Alaska construction workers were 45 years old or older in 2004 (up from 23 percent in 1994), while 17 percent were 50 years old or older. If the start of pipeline construction is delayed by five or ten years, Alaska's construction workforce may lose the experience of older workers requiring greater import of outside labor for the highest skilled jobs.[3]

Figure 8 shows the impact of a delay on the Alaska Permanent Fund. Figure 8 shows cumulative Permanent Fund deposits and earnings, less dividends paid out, adjusted for inflation. Earnings are estimated based on 7.6 percent return on investment. We assume 25 percent of the state's project-related revenues are deposited into the permanent fund.

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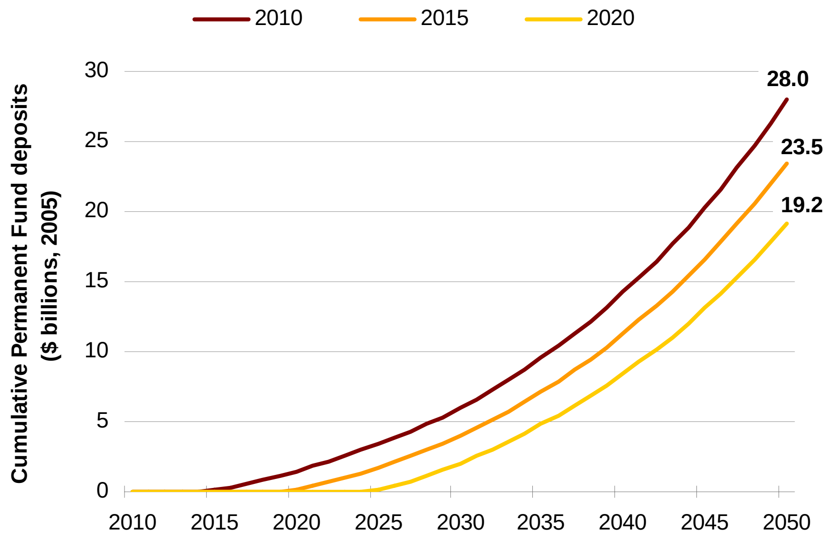
[3] With good planning, a longer time period before start up could allow more young workers to be trained to fill expected pipeline construction jobs. Until a start-date is known, however, the state is in a Catch 22: failing to target the right crafts and train workers to fill jobs created both by retirement and pipeline construction will result in greater-than-predicted out-of-state hiring, but ramping up apprenticeship and other training programs without certain knowledge that those workers will have jobs when their training is complete will cause unnecessary expense and create an unused pool of prepared workers who may move out of state to use their training.

Figure 8: Impact of delay on Permanent Fund deposits



Summary of effects of delay on the sponsor group project

The following table summarizes the economic, fiscal and workforce impacts of delay on the sponsor group project using baseline assumptions:

Figure 9: Impacts of delay on the sponsor group project

Project Timeline	0 years	5 years	10 years
Year in which construction expected to start	2011	2016	2021
Year in which gas first flows	2015	2020	2025
Year in which last gas flows through pipeline	2050	2050	2050
Well head and Tariff	**0 years**	**5 years**	**10 years**
Well head natural gas price	$3.43	$3.50	$3.57
Total pipeline tariff	$2.07	$2.00	$1.93
Economic and Fiscal Impacts	**0 years**	**5 years**	**10 years**
NPV (at 5%) to local governments ($ billions, 2005 dollars)	$1.7	$1.3	$1.0
NPV (at 5%) to state government ($ billions, 2005)	$25.3	$20.8	$16.6
NPV (at 10%) to producers ($ billions, 2005)	$17.6	$12.2	$8.3
Total NPV ($ billions, 2005) [1]	$44.6	$34.3	$25.9
Ave. annual spending of project-related revenues by state and local governments ($billions, 2005) [2]	$1.6	$1.6	$1.6
Ave. annual pipeline operations spending ($billions, 2005)[2]	$0.3	$0.3	$0.3
Total post-construction spending, all sources ($billions, 2005)[2]	$69.1	$59.9	$50.7
Cumulative effect on Alaska Permanent Fund balance ($billions, 2005)[3]	$28.0	$23.5	$19.2
Workforce Impacts	**0 years**	**5 years**	**10 years**
Total project-related jobs during construction[4]	68,000	68,000	68,000
Ave. annual project-related jobs during construction[4]	14,000	14,000	14,000
Total jobs from pipeline operations[4]	48,000	41,000	34,000
Ave. annual jobs from pipeline operations[4]	1,300	1,300	1,300
Total Jobs generated by state and local spending[4]	901,000	781,000	663,000
Ave. annual jobs from state and local spending[4]	25,000	25,000	25,000
Total jobs all sources all years[4]	1,016,000	890,000	765,000

Notes:

1) 10 percent discount rate for producer earnings; 5 percent discount rate for state and local revenues.

2) Cumulative deposits and earnings less dividends, adjusted for inflation, based on 7.6 percent return and current law for dividends.

3) Direct spending in real 2005 dollars.

4) Includes direct, indirect and induced jobs, where 1 job is a full or part-time job over the course of a single year.

PART II. COMPARATIVE ANALYSIS OF ALTERNATIVE PROJECTS FOR DEVELOPING ANS NATURAL GAS

In the second part of the study we compare the impacts from three different scenarios for bringing Alaska gas to market, based on our best estimates of costs and prices. Construction costs are based on numbers provided by the sponsor group and the Alaska Gasline Port Authority (AGPA), but where their costs for the same project components differ, we have adjusted them to produce a better “apples to apples” comparison. For this reason, the results shown for the AlCan pipeline project in the earlier section of this study vary somewhat from the impacts here. Key assumptions and results of our comparative models appear in Figure 22 through Figure 25 at the end of the Executive Summary.

We analyzed the results of our models to determine which project would bring the greatest overall economic and social benefits to Alaska. This conforms to Article 8, Sections 1 and 2 of the Alaska State Constitution, which specifies that the natural resources of the state of Alaska will be developed for the “maximum benefit of its people.”

Based on our analysis, we conclude that the AlCan pipeline proposed by the Sponsor group maximizes the value of Alaska’s North Slope natural gas resources by producing the highest revenues for the state and creating the greatest number of jobs for Alaskans over the life of the project. While any project may meet with unanticipated delays, our analysis of known delays also favors an AlCan pipeline, which is the only scenario that starts with an assured supply of gas.

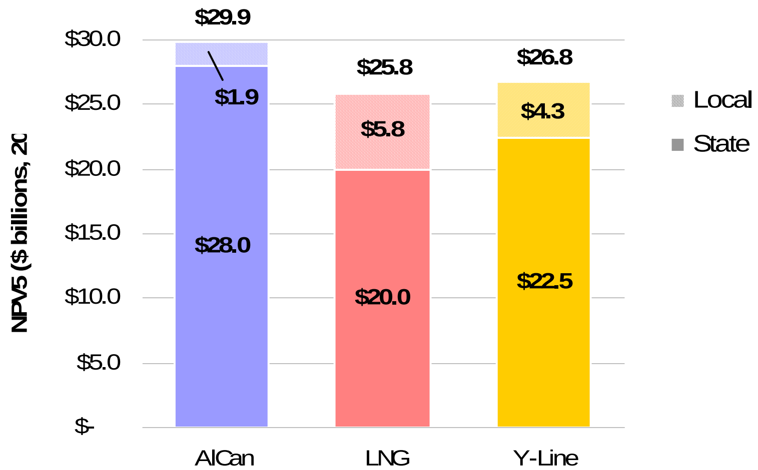
Fiscal and Economic Impact Comparison

Once a pipeline becomes operational, our model estimates the NPV of a project to Alaska state and local government to be as follows, assuming a 5 percent governmental discount rate:

- $29.9 billion or $1.6 billion per year from an AlCan pipeline;
- $25.8 billion or $1.5 billion per year from an LNG pipeline;
- $26.8 billion or $1.8 billion per year from a Y-line pipeline

As before, project revenues are expressed in real terms in 2005 dollars and include the effects of gains and losses in North Slope oil production due to a gas project, as well as revenues from the sale of natural gas and natural gas liquids.

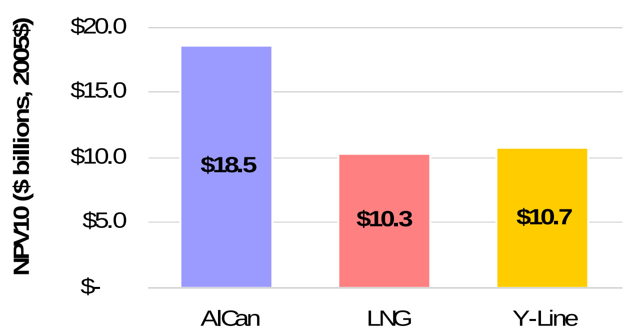
Figure 10: Present value of state and local government revenues from gas projects



Note: NPV at 5 percent

The producers currently own the leases to develop North Slope oil and natural gas. They will maximize their profits with an AlCan project as shown in the figure below. These figures show the net present value of all expected costs and profits based on our models.

Figure 11: Net present value of alternative projects to the producers



Note: NPV at 10 percent

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 liquid and for dry gas itself owning to the U.S. and Europe's strong demand and tight supplies.

Given the premium to 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 in the area covered by the lease as long as they stick to the lease terms. We find it reasonable to assume that an attempt to extinguish the producers' interest in North Slope gas by taking back leases through legislative or legal means would result in protracted litigation, delaying the start of a gas pipeline project.

Alternatively, if the state wished to buy back the leases from the producers, we assume it would take two to three years to negotiate the buyout. Additional time would be required to account for all environmental and infrastructure problems and to determine a temporary owner/operator. The state would then have to set up new lease sales and solicit bids from prospective buyers who agree to participate in an Alaska LNG or Y-line project. A new lease sale might require a new environmental permitting process. In all, a buyout could take five to ten years even if the process goes smoothly and does not result in protests or further litigation. For purposes of our comparison, we assumed a five-year delay.

Value destruction

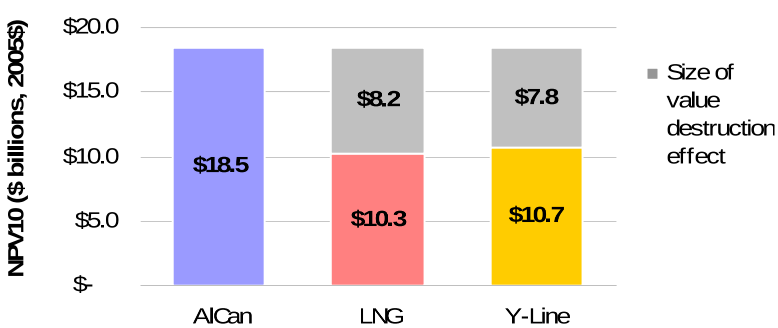
The concept of value destruction as it applies to the Alaska gas project and the importance of impacts of delay are central to understanding why the AlCan project is the superior choice for Alaska compared to an Alaska LNG or Y-line project.

We use the term value destruction to describe the loss in a project's value to the producers should natural gas be sold to an LNG or Y-line project. The value destruction effect can be illustrated by two scenarios: (a) if the producers sell gas to an LNG or Y-line project, their return from the gas declines with no comparable increase to other parties, resulting in potentially compensable loss in value of the producers' North Slope leases; or (b) if the state buys back the gas leases and reissues them with the requirement that gas be shipped to market through an Alaska LNG or Y-line project, the state's return from the leases will decline as new leaseholders reduce their bids by the amount of value destroyed.

The size of the value destruction effect is equal to the difference in the NPV to North Slope oil and gas producers of an Alaska LNG or Y-line project compared with the value of a producer-owned pipeline bringing gas to the Chicago market.

Our analysis shows that the value destruction effect is substantial for both the Alaska LNG and Y-line projects, resulting in lower state revenues and a significant reduction in jobs generated by state spending of gas revenues. Either project would result in the state losing $8 billion to $10 billion in lease sales revenue if the new leases include the stipulation that an all Alaska LNG or Y-line project be built. This estimate does not include the potential costs of litigation, contract negotiations, new permitting or costs associated with setting up the lease sales.

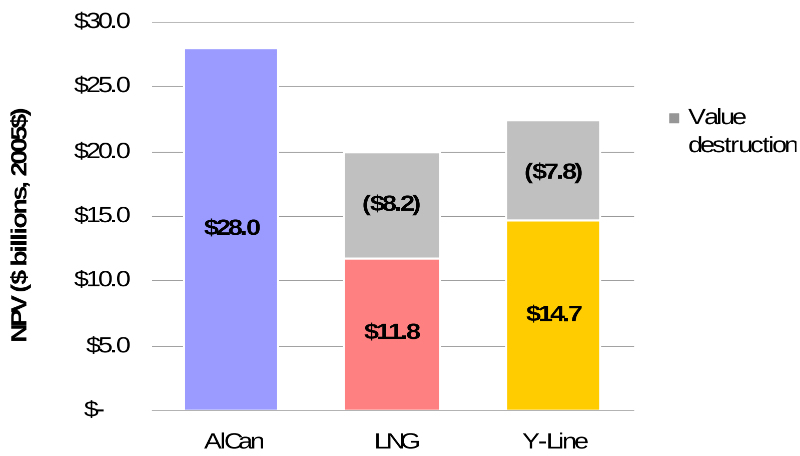
Figure 12: Size of value destruction effect for LNG and Y-line projects



Note: NPV at 10 percent

Earlier we showed the present value of an Alaska LNG project to state and local governments to be $25.8 billion. After accounting for value destruction, we expect the NPV to fall to $17.6 billion, while the NPV of a Y-line project to the state and municipalities drops from $26.8 billion to $19 billion once value destruction is taken into account. Once again, each of the NPV models uses a five percent discount rate for state and local government revenues.

Figure 13: The effect of value destruction on state revenues



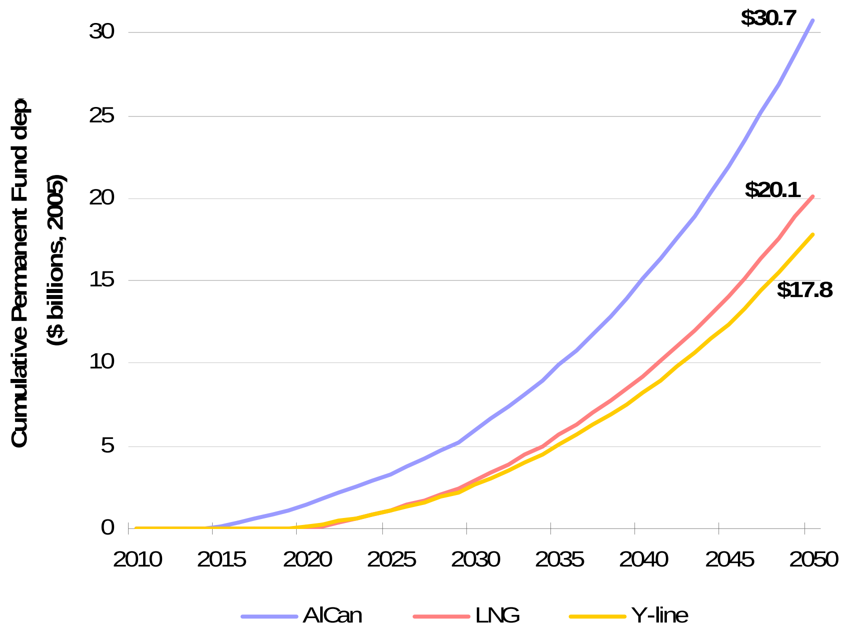
Note: NPV at 5 percent

This lost revenue would result in reduced state and local government spending and could cost Alaska the equivalent of 8,500 jobs on an annual basis due the economic multiplier effects of public and private spending. By including the lost revenue in the NPV calculations for all three projects, our model provides an accurate projection of total economic impacts and shows that the AlCan project maximizes value to Alaska.

Permanent Fund earnings

As shown, the three projects generate significant differences in revenue streams to the state. While the Alaska LNG and Y-line projects create additional municipal revenue as shown in Figure 10, it comes at the cost of a lower wellhead value, and thus lowers royalty payments to the state. Over time, the aggregate amount deposited in the Alaska Permanent Fund also suffers, with a corresponding reduction in annual Permanent Fund Dividend payments to Alaskans. The following figure shows the impact on the Alaska Permanent Fund, including deposits and cumulative earnings (less dividends paid out). Earnings are again estimated at 7.6 percent.

Figure 14: Impact of project revenues on Alaska Permanent Fund balance



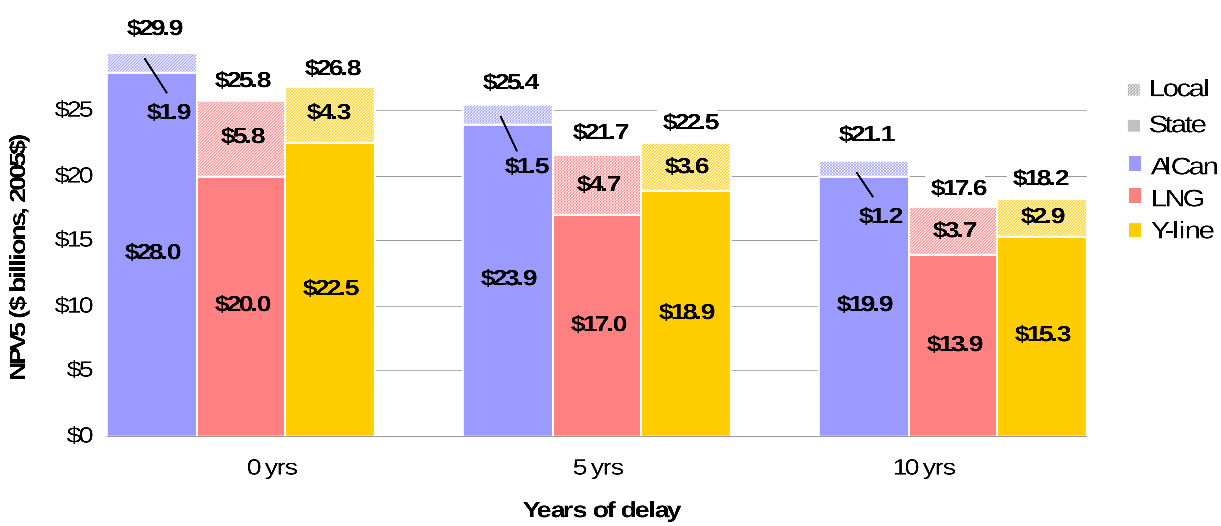
Note: Cumulative deposits plus earnings (at 7.6 percent), less dividends paid

Impact of delay

There are many reasons why a gas pipeline project might be delayed, some of which are discussed in the section on Known Challenges. Any delay in the start of construction will reduce the NPV of a project to the state and local governments as well as to the producers.

For each year of delay, we estimate the present value revenue loss to state and local governments would be approximately one billion dollars per year for any of the proposed projects.

Figure 15: Effect of delay on state and local revenues



Note: NPV at 5 percent

The state faces at least two other challenges from a delay in construction. With oil production in decline and gas revenue at least ten years off, a significant delay in project startup could result in a fiscal gap, and forcing severe budget cutbacks unless new sources of revenue or savings are found.

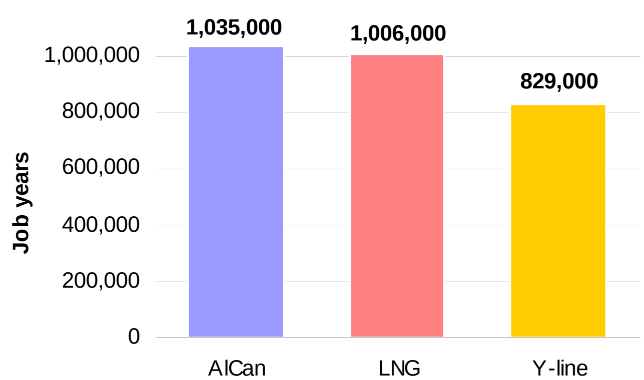
The second challenge stems from the aging of Alaska's skilled workforce. A five or ten year delay in the project could result in lower resident hire rates if Alaska's older skilled construction workers retire or leave the state.

Workforce impacts

The Information Insights' model projects increased labor force needs in Alaska – direct, indirect and induced jobs – for construction of a the gas pipeline project and for project operations through 2050. (Note that in these estimates one job or job year represents one full or part-time job over the course of a single year.)

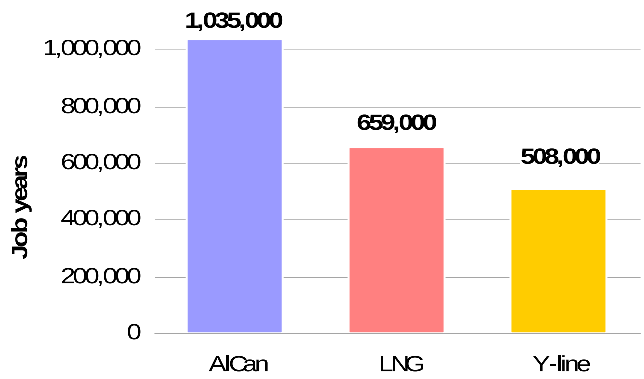
- The AlCan project increases the state's labor force needs by an average of 18,000 direct, indirect and induced workers per year during construction. The project also creates a sustained impact of about 26,000 jobs per year after construction from both pipeline operations and jobs generated by state and local spending of project-related oil and gas revenue.
- The LNG project increases the state's labor force needs by an average of 19,000 direct, indirect, and induced workers during construction, and results in a sustained increase of 27,000 jobs per year after construction. These job gains are reduced however when the effect of value destruction on state spending is taken into account. We estimate the size of the value destruction effect to be 347,000 job years.
- The Y-line project has average workforce needs of about 22,000 during construction and a sustained addition of nearly 23,000 workers thereafter. However, due to reduced spending of state revenues, the Y-line results in 321,000 fewer job years than an AlCan project when effect of value destruction is included.

Figure 16: Total jobs from all sources through 2050



Note: Includes direct, indirect and induced full and part-time jobs over the course of one year

Figure 17: Effect of value destruction on total jobs



Note: Includes direct, indirect and induced full and part-time jobs over the course of one year

The following series of figures illustrates the different job profiles the three scenarios present. One of the challenges of the Y-line profile is the large spike in jobs during the initial construction phase that could represent an unusually severe boom and bust. The spike appears during the second year of construction when building on a North Slope conditioning plant is critical, requiring extra work. At the same time, there is on-going pipeline construction, while construction on a south shore liquefaction project is in full swing, exacerbating the total Alaska labor demand. During year two of a Y-line project, the total employment effect on the state is 36,000 workers, while only 21,000 workers are needed the prior year, and only 28,000 the year after. This spike in demand will cause extra strain on the state's ability to take care of new Alaskan residents who may find themselves out of work in post-construction years.

The following charts include direct, indirect and induced labor impacts of the three projects.

Figure 18: Workforce impacts from project construction and operations

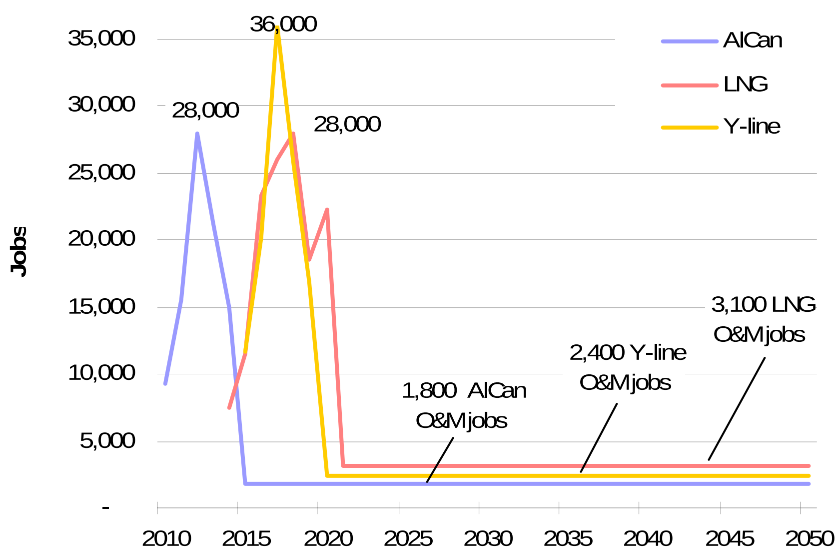


Figure 19: Workforce impact of project-related state and local spending

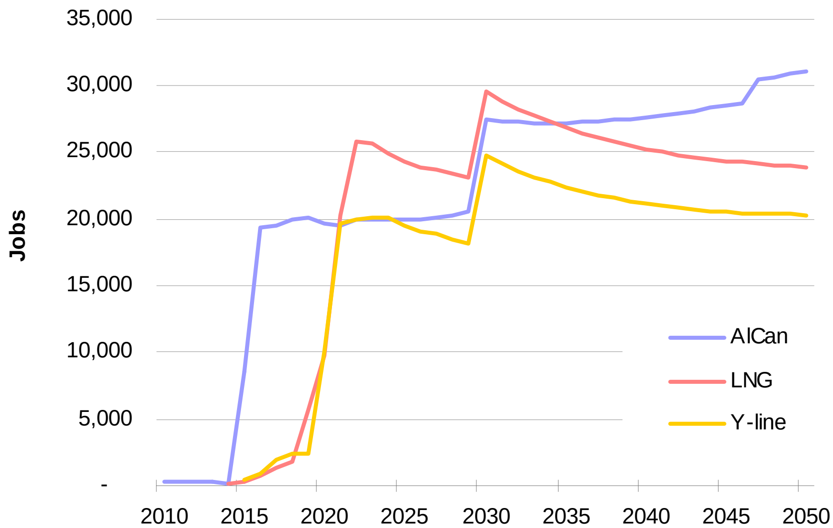


Figure 20: Total jobs from all sources through 2050

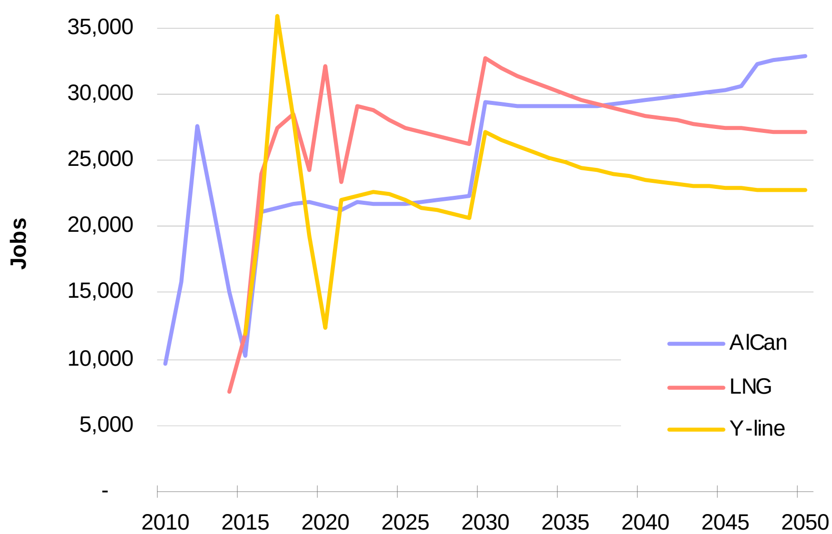
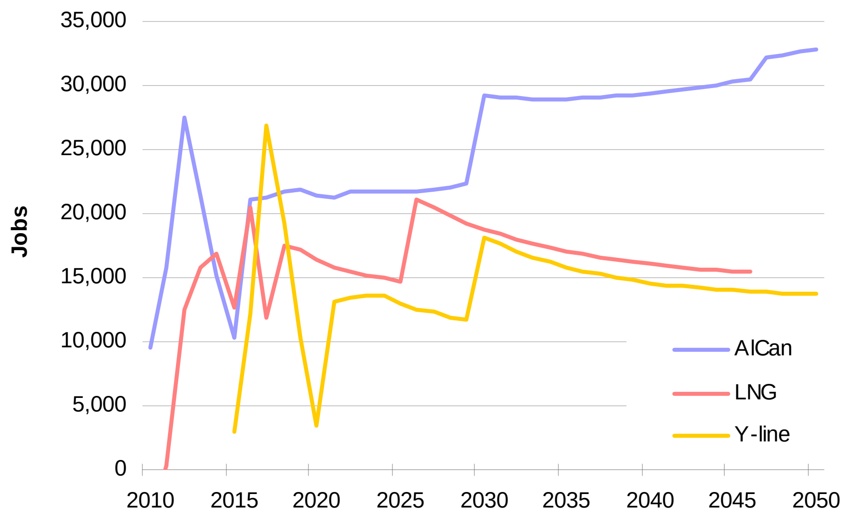


Figure 21: Total jobs showing effect of value destruction



Summary of Results of Comparative Analysis

Figure 22 through Figure 25 summarize the assumptions, issues and impacts identified in our comparison of the three scenarios for developing Alaska North Slope natural gas.

Figure 22: Summary of project descriptions and assumptions

Project Description	AlCan Project (adjusted for comparison)	Alaska LNG Project	Y-line Project
Total capacity	4.5 bcf/d	4.0 bcf/d	4.5 bcf/d
Pipeline size	52-inch to Alberta; 24-inch for the spur line to Anchorage	56-inch to Delta Junction; 48-inch Delta Junction to Valdez; 24-inch for the spurline to Anchorage	56-inch to Delta Junction; 48-inch to Alberta; 36-inch to Valdez; 24-inch for the spur line to Anchorage
In-state use	0.25 bcf/d	0.25 bcf/d	0.25 bcf/d
Market	Chicago/Alberta/Atlantic Basin	West Coast/Pacific Rim	Chicago/Alberta/Atlantic Basin West Coast/Pacific Rim
Project Assumptions	**AlCan Project (adjusted for comparison)**	**Alaska LNG Project**	**Y-line Project**
Construction start	2011	2015	2016
Construction period	4 years	6 years	4 years
First gas flows	2015	2019	2020
Project cost[1]	$21 billion to Alberta $27 billion to Chicago	$25 billion to West Coast	$26 billion to Alberta and West Coast
Market size	100 bcf/d	20 bcf/d	Combined
Gas price[1]	$5.33/mmBtu Chicago $4.33/mmBtu Alberta	$4.54/mmBtu U.S. and Canadian West Coast average LNG $4.15/mmBtu B.C. LNG	$5.33/mmBtu Chicago $5.13/mmBtu LNG
Fuel Losses	11.30% to Alberta (0.53 bcf/d)	17.6% (0.8 bcf/d)	11.50% (0.55 bcf/d)
Well head after tariff	$3.01	$2.50	$2.73

Figure 23: Summary of known challenges

Known Challenges	AlCan Project (adjusted for comparison)	Alaska LNG Project	Y-line Project
Gas supply	Yes	Need to acquire	Need to acquire
ROW permits	Need to acquire First Nations issues Need Environmental Impact Statement	Existing permits may need updating and expanding Need to extend permits for a 30-year project Need some environmental studies and permitting	Mixed
First Nations issues	Some	None	Some plus equity issue
Tariffing issue	None	With greater municipal share, FERC may need to change methods	With greater municipal share, FERC may need to change methods
Receiving sites & LNG terminals	Pipe capacity from Alberta to Chicago exists	Poor prospects for 4 terminals	Poor prospects for 2 terminals Pipe capacity from Alberta to Chicago exists
Equity issue	Small	Small	Canadian regions may want equity too. Potential for delay due to negotiations.
Proposal stability	Firm	Changing	Conceptual
Construction delays	Possible Due to steel supplies, workforce issues, permitting issues	Likely Due to contract talks, tanker and terminal readiness, workforce issues, and legal challenge of obtaining gas from existing lease holders	Likely Same as Alaska LNG

Figure 24: Summary of workforce impacts

Workforce Impacts through 2050	AlCan Project (adjusted for comparison)	Alaska LNG Project	Y-line Project
Project construction jobs[1] (Direct only)	53,000 Total 11,000 Ave. per year	80,000 Total 11,000 Ave. per year	66,000 Total 13,000 Ave. per year
Additional jobs during construction[1] (Indirect + induced)	35,000 Total 7,000 Annual average	55,000 Total 8,000 Annual average	43,000 Total 9,000 Annual average
Jobs from project operations[1] (Direct only)	16,000 Total 500 Annual average	22,000 Total 700 Annual average	18,000 Total 600 Annual average
Additional jobs during operations[1] (Indirect + induced)	49,000 Total 1,400 Annual average	72,000 Total 2,400 Annual average	56,000 Total 1,800 Annual average
Jobs from local and state spending of gas revenues[1,2]	882,000 Total 22,000 Annual average	776,000 Total 21,000 Annual average	646,000 Total 18,000 Annual average
Total jobs from all sources all years[1,2]	1,035,000	1,006,000	829,000
Jobs lost to value destruction[1,2]	0	347,000	321,000
Total jobs from all sources all years after value destruction[1,2]	1,035,000	659,000	58,000

Notes:

1) One job represents a full or part-time job over the course of a single year.

2) Includes direct, indirect and induced jobs

Figure 25: Three-project comparison: Fiscal Impacts

Fiscal Impacts through 2050	AlCan Project (adjusted for comparison)	Alaska LNG Project	Y-line Project
NPV (at 5%) to local governments[1]	$1.9 billion	$5.3 billion	$4.3 billion
NPV (at 5%) to state[1]	$28.0 billion	$20.0 billion	$22.5 billion
NPV (at 10%) to producers[1]	$18.5 billion	$10.3 billion	$10.7 billion
Total NPV[1,2]	$48.4 billion	$36.1 billion	$37.5 billion
Cost of delay to state[1]	$900 million per year	$700 million per year	$800 million per year
Average state and local spending of project-related revenue[1] (Direct spending)	$1.6 billion per year	$1.6 billion per year	$1.3 billion per year
Average project spending after construction[1]	$400 million per year	$700 million per year	$500 million per year
Total local, state and project spending after construction[1]	$71.8 billion	$69.5 billion	$57.8 billion
Reduction in NPV due to value destruction[1]	None	$8.2 billion	$7.8 billion
Alaska Permanent Fund balance in 2051 from project[1,3]	$30.7 billion	$20.1 billion	$17.8 billion

Notes:

1) 2005 dollars
2) Assumes 10 percent discount rate for producers; 5 percent rate for government
3) Cumulative earnings, net of dividends paid, based on 7.6 percent return and current dividend law

Appendix I

Stranded Gas Development Act Conforming Amendments

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HOUSE BILL NO.

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-FOURTH LEGISLATURE - SECOND SPECIAL SESSION

BY THE HOUSE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

Introduced:
Referred:

A BILL

FOR AN ACT ENTITLED

"An Act relating to the Alaska Stranded Gas Development Act, including clarifications or provision of additional authority for the development of stranded gas fiscal contract terms; making a conforming amendment to the Revised Uniform Arbitration Act; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* **Section 1.** AS 43.82.010 is amended to read:

Sec. 43.82.010. Purpose. The purpose of this chapter is to

(1) encourage new investment to develop the state's stranded gas resources by authorizing establishment of fiscal terms related to **<u>royalties and taxes for a qualified sponsor, the members of a qualified sponsor group, or a related party; in this paragraph, "taxes" includes taxes on oil and gas production, income, and property</u>** [THAT NEW INVESTMENT WITHOUT SIGNIFICANTLY ALTERING TAX AND ROYALTY METHODOLOGIES AND RATES ON EXISTING OIL AND GAS INFRASTRUCTURE AND PRODUCTION];

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(2) allow the fiscal terms applicable to a qualified sponsor**,** [OR] the members of a qualified sponsor group**, or a related party**, 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

(3) maximize the benefit to the people of the state of the development of the state's stranded gas resources.

* **Sec. 2.** AS 43.82.020 is amended to read:

Sec. 43.82.020. Negotiation of contract terms [CONTRACTS FOR PAYMENTS IN LIEU OF OTHER TAXES AND FOR ROYALTY ADJUSTMENTS]. The commissioner may, under this chapter, negotiate terms for inclusion in a proposed contract with a qualified sponsor or qualified sponsor group providing for

(1) periodic payment in lieu of one or more taxes that otherwise would be imposed by the state or a municipality on the qualified sponsor**,** [OR] members of the qualified sponsor group**, or a related party;** [AS A CONSEQUENCE OF THE SPONSOR'S OR GROUP'S PARTICIPATION IN AN APPROVED QUALIFIED PROJECT UNDER THIS CHAPTER; AND]

(2) certain adjustments regarding **oil and gas lease agreements, including** royalty **provisions, unit agreements, and other agreements** under AS 43.82.220**; in this paragraph, "oil and gas lease agreements" includes royalty provisions of those agreements;**

(3) payment of gas production tax under AS 43.55, or payment in lieu of gas production tax, by delivery of gas; and

(4) acquisition by the state of an ownership interest in the project that is the subject of the proposed contract, and terms relating to collateral agreements authorized under AS 43.82.437.

* **Sec. 3.** AS 43.82.200 is amended to read:

Sec. 43.82.200. Contract development. If the commissioner approves an application and proposed project plan under AS 43.82.140, the commissioner may develop a contract that may include

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(1) terms concerning **modifications of taxes on oil and gas production, income, and property, including terms providing for** periodic payment in lieu of one or more taxes as provided in AS 43.82.210**, and terms related to credits for investment in a project that is the subject of a contract developed under this chapter**;

(2) terms developed under AS 43.82.220 **concerning oil and gas leases, unit agreements, and other agreements under AS 38, including terms** relating to

(A) timing and notice of the state's right to take royalty in kind or in value; and

(B) royalty value;

(3) terms regarding the hiring of Alaska residents and contracting with Alaska businesses under AS 43.82.230;

(4) terms regarding periodic payment to, or an equity or other interest in a project for, municipalities under AS 43.82.500;

(5) terms regarding arbitration or alternative dispute resolution procedures;

(6) terms and conditions for administrative termination of a contract under AS 43.82.445; [AND]

(7) **terms and conditions regarding the acquisition by the state of an ownership interest in the project that is the subject of the proposed contract;**

(8) terms and conditions regarding the implementation of an election by the state to receive its gas production tax payments under AS 43.55, or payments in lieu of the gas production tax, by delivery of gas to the state;

(9) terms and conditions relating to the payment of the obligations owed among the state and a qualified sponsor, the members of a qualified sponsor group, or a related party through credit, offset, or recoupment, including terms and conditions providing for refund or reimbursement of taxes, or payments in lieu of those taxes, paid in excess of any fiscal term contained in the contract limiting obligations for state or local taxes identified in AS 43.20.210(a),

(10) terms and conditions relating to the administration of the

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<u>contract, force majeure and suspension of contractual obligations, payment of interest by either the state or a qualified sponsor or a related party on any unpaid obligations owed under the contract, preservation of the confidentiality of certain proprietary or other information agreed to be held confidential under the contract, and audits of obligations owed to the state or the qualified sponsor, the members of a qualified sponsor group, or a related party under the contract, including agreements relating to taxes described in AS 43.82.210(a), or payments in lieu of those taxes;</u>

<u>(11) terms and conditions by which the state may acquire, directly or indirectly, sufficient capacity for any gas received by the state and shipped to market on the project that is the subject of the contract;</u>

<u>(12) subject to the concurrence of the attorney general, terms and conditions relating to agreements to waive sovereign immunity of the state, agreements by the state to indemnify, or otherwise hold harmless, a qualified sponsor or related party, agreements limiting claims for damages and remedies for losses incurred by the state, and agreements relating to the state's position with regard to the jurisdiction of the Regulatory Commission of Alaska under AS 42.04; and</u>

<u>(13)</u> other terms or conditions that are

(A) necessary to further the purposes of this chapter; or

(B) in the best interests of the state.

*** Sec. 4.** AS 43.82.210(a) is amended to read:

(a) If the commissioner approves an application and proposed project plan under AS 43.82.140, the commissioner may develop proposed terms for inclusion in a contract under AS 43.82.020 for periodic payment in lieu of one or more of the following taxes that otherwise would be imposed by the state or a municipality on the qualified sponsor**<u>,</u>** [OR] member of a qualified sponsor group**<u>, or a related party</u>** [AS A CONSEQUENCE OF PARTICIPATING IN AN APPROVED QUALIFIED PROJECT]:

(1) oil and gas production taxes and oil surcharges under AS 43.55;

(2) oil and gas exploration, production, and pipeline transportation

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property taxes under AS 43.56;

(3) [REPEALED

(4)] Alaska net income tax under AS 43.20;

(4) [(5)] municipal sales and use tax under AS 29.45.650 - 29.45.710;

(5) [(6)] municipal property tax under AS 29.45.010 - 29.45.250 or 29.45.550 - 29.45.600;

(6) [(7)] municipal special assessments under AS 29.46;

(7) [(8)] a comparable tax or levy imposed by the state or a municipality after June 18, 1998;

(8) [(9)] other state or municipal taxes or categories of taxes identified by the commissioner**, including taxes on oil or gas reserves or on oil and gas resources, taxes not authorized or imposed by the state or a municipality at the time a contract developed under this chapter takes effect, and taxes enacted by initiative**.

* **Sec. 5.** AS 43.82.220(a) is amended to read:

(a) Notwithstanding any contrary provisions of AS 38, **or regulations adopted under that title,** the commissioner of natural resources, with the concurrence of the commissioner of revenue and**, if necessary,** the affected parties holding a state lease or unit agreement, may develop proposed terms for inclusion in a contract under AS 43.82.020 that modify [THE TIMING AND NOTICE] provisions of the applicable oil and gas leases**,** [AND] unit agreements**, and other agreements under AS 38, including provisions**

(1) pertaining to the state's rights to receive its royalty on gas in kind or in value if

(A) [(1)] the viability of the approved qualified project depends on long-term gas **shipping commitments** [PURCHASE AND SALE AGREEMENTS];

(B) [(2)] certainty over time regarding the quantity of royalty gas that the state may be taking in kind is needed to **enter into long term gas shipping commitments or marketing agreements** [SECURE THE LONG-TERM PURCHASE AND SALE AGREEMENTS];

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[(3) THE SPECIFIED PERIOD OF THE STATE'S COMMITMENT TO TAKE ITS ROYALTY SHARE IN VALUE OR IN KIND DOES NOT EXCEED THE TERM OF THE PURCHASE AND SALE AGREEMENTS;] and

(C) [(4)] the modification does not impair the ability of the approved qualified project or the state to meet the reasonably foreseeable demand in this state for gas within economic proximity of the project during the term of the contract developed under AS 43.82.020**; and**

(2) relating to lease or unit expenses for separation, cleaning, dehydration, gathering, salt water disposal, and preparation for transportation on or off the lease.

* **Sec. 6.** AS 43.82.220(c) is amended to read:

(c) The commissioner of revenue shall include any proposed terms [RELATING TO ROYALTY] developed in accordance with this section in the proposed contract under AS 43.82.400.

* **Sec. 7.** AS 43.82.220 is amended by adding a new subsection to read:

(e) An agreement by the state to take royalty gas in kind as part of a contract developed under this chapter that satisfies (a)(1)(A) - (C) of this section is not subject to the provisions of AS 38, or regulations adopted under that title, relating to decisions to take royalty in kind.

* **Sec. 8.** AS 43.82.250 is amended to read:

Sec. 43.82.250. Term of contract; effective date. The term of a contract developed under AS 43.82.020 [MAY BE FOR NO LONGER THAN IS NECESSARY TO DEVELOP THE STRANDED GAS THAT IS SUBJECT TO THE CONTRACT; HOWEVER, THE TERM OF THE CONTRACT] may not exceed 35 years from the commencement of commercial operations of the approved qualified project**, excluding suspensions of contract obligations that are covered by the force majeure terms of any contract developed under this chapter. However, the term of contract may not exceed 45 years from the effective date of a contract approved under AS 43.82.435**.

* **Sec. 9.** AS 43.82.260(b) is amended to read:

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(b) A contract developed under this chapter may provide for the

(1) assignment to or withdrawal of a qualified sponsor or member of a qualified sponsor group**; or**

(2) addition of new parties to the contract under terms and conditions provided in the contract.

* **Sec. 10.** AS 43.82.270 is amended to read:

Sec. 43.82.270. Project plans and work commitments. A contract under AS 43.82.020 must include **provisions for implementation of** the qualified project plan approved under AS 43.82.140**, as may be modified as a result of the development of a contract under this chapter,** and provisions for updating the plan at reasonable intervals until the commencement of commercial operations of the approved qualified project. The commissioner of revenue, in consultation with the commissioner of natural resources, may, as a term in a contract under AS 43.82.020, include work commitments or other obligations in the contract to be accomplished before the commencement of commercial operations of the approved qualified project.

* **Sec. 11.** AS 43.82 is amended by adding a new section to read:

Sec. 43.82.437. Collateral agreements. (a) The commissioner of revenue, with the concurrence of the commissioner of natural resources, may negotiate and enter into collateral agreements that are required to implement the state's acquisition of an ownership interest in the project that is the subject of a proposed contract developed under this chapter. The authority of the commissioner of revenue to negotiate and enter into collateral agreements on behalf of the state lapses 60 days after the effective date of the law authorizing the contract under AS 43.82.435.

(b) A collateral agreement entered into by the commissioner of revenue on behalf of a public corporation that is established by law to enter into agreements to acquire an ownership interest in the project to be developed under the authorized contract is an obligation of the corporation and shall be executed and implemented by the board of directors of the public corporation after the board is appointed and able to transact business for the corporation. The authority of the commissioner to negotiate and enter into collateral agreements on behalf of the public corporation lapses when

(1) a public corporation has been established by law to finance and

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own the state's interest in the project to be developed under contract authorized under this chapter; and

(2) all members of the initial board of directors of that corporation have been appointed by the governor.

(c) A collateral agreement executed by the commissioner on behalf of a public corporation that has been established for that purpose is binding only on the public corporation and does not render the state a party to the collateral agreement.

(d) Except as provided in this section and in AS 43.82.310, a collateral agreement necessary to implement a contract that has been authorized by the legislature under the terms of AS 43.82.435 is not subject to any of the provisions of this chapter.

(e) In this section, "collateral agreement" includes agreements between either the state or entities established by the state, and a qualified sponsor or qualified sponsor group, or affiliates of those entities, to form limited liability companies, limited liability partnerships, or any other recognized form of business association, whether incorporated or unincorporated, that would own or operate any portion of the project that is the subject of a proposed contract developed under this chapter.

* **Sec. 12.** AS 43.82.445(a) is amended to read:

(a) The commissioner **<u>may</u>** [SHALL] include terms in a contract developed under AS 43.82.020 that provide for administrative termination of a party's rights under the procedures and conditions set out in **<u>the contract</u>** [THIS SECTION] if the party has

(1) ceased to meet the requirements of AS 43.82.110 as a qualified sponsor or qualified sponsor group;

(2) intentionally or fraudulently misrepresented, in whole or in part, material facts or circumstances upon which the contract was made;

(3) failed to comply with a condition or material term of the contract or a provision of this chapter; or

(4) failed to comply with the approved qualified project plan**<u>, as modified as a result of the development of contract under this chapter,</u>** or any updated project plan **<u>required by that contract</u>**.

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* **Sec. 13.** AS 43.82.500 is amended to read:

Sec. 43.82.500. Obligation to share payments with municipalities. If the commissioner develops a contract under AS 43.82.020 that includes terms that exempt a **qualified sponsor, the members of a qualified sponsor group, or a related** party to the contract, and the property, gas, products, and activities associated with the approved qualified project that is subject to the contract, from a municipal tax or assessment in accordance with AS 29.45.810 or AS 29.46.010(b), or AS 43.82.200 and 43.82.210, the commissioner shall include a term in the contract that **provides for** [THE PARTY PAY] a portion of the periodic payments **to be made payable** [DUE UNDER THE CONTRACT] to the revenue-affected municipality.

* **Sec. 14.** AS 43.82.505 is amended to read:

Sec. 43.82.505. Payments to economically affected municipalities. If the commissioner executes a contract under AS 43.82.020 that will produce one or more economically affected municipalities, the commissioner shall include a term in the contract that provides for [A PORTION OF THE] periodic **impact** payments to **the state that may be appropriated to the Alaska Natural Gas Pipeline Construction Impact Fund established in (c) of this section to benefit** the economically affected municipalities under the principles in AS 43.82.520.

* **Sec .15.** AS 43.82.505 is amended by adding new subsections to read:

(b) A special account is established in the general fund into which the Department of Revenue shall deposit impact payments received by the state under (a) of this section.

(c) The Alaska Natural Gas Pipeline Construction Impact Fund is established in the Department of Revenue. The legislature may appropriate money deposited in the special account established in (b) of this section, as well as any additional money considered necessary, to the Alaska Natural Gas Pipeline Construction Impact Fund to address the economic and social impacts incurred by a municipality during the construction of a project that is the subject of a proposed contract developed under this chapter.

(d) Nothing in this chapter exempts money deposited into the special account in the general fund established in (b) of this section from the requirements of AS 37.07

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(Executive Budget Act) or dedicates that money for a specific purpose.

* **Sec. 16.** AS 43.82.520(b) is amended to read:

(b) In developing a contract under AS 43.82.200 - 43.82.270, the commissioner shall ensure that each revenue-affected municipality and economically affected municipality receives a fair and reasonable share of the payments provided under AS 43.82.210**, including any impact payment money under AS 43.82.505 that is appropriated,** in accordance with the following principles:

(1) the share of the payments to revenue-affected municipalities should be given priority over payments to economically affected municipalities with due regard to the anticipated size of the tax base that the contract would exempt from municipal taxation by revenue-affected municipalities;

(2) the share of the payments to municipalities should be determined with due regard to the [ANTICIPATED] economic and social burdens that **are** [WOULD BE] imposed on the municipality by construction and operation of the project;

(3) the respective shares of the total payments to the state and to municipalities should be fixed in a manner to ensure that their respective interests are aligned;

(4) to the extent practicable, the periodic amounts paid to each of the municipalities should be stable and predictable; and

(5) to the extent practicable, the provisions for sharing payments with municipalities should be consistent with the principles established in AS 43.82.210(b).

* **Sec. 17.** AS 43.82 is amended by adding a new section to read:

Sec. 43.82.625. Issuance of exemption certificates. If a contract is authorized by the legislature under AS 43.82.435, the commissioner may establish procedures for the issuance of exemption certificates in accordance with the terms of the exemptions from state or municipal taxes that are provided in the contract.

* **Sec. 18.** AS 43.82.900 is amended by adding a new paragraph to read:

(14) "related party" means an entity, including a limited liability company or similar incorporated or unincorporated entity, that

(A) is affiliated with a qualified sponsor or qualified sponsor

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group;

(B) owns or operates a qualified project or any segment of a qualified project; and

(C) is an intended beneficiary of the fiscal terms included in a contract developed under this chapter.

* **Sec. 19.** AS 09.43.300(a) is amended to read:

(a) AS 09.43.300 - 09.43.595 govern an agreement to arbitrate made on or after January 1, 2005**<u>, except as otherwise provided in a contract term developed under AS 43.82.200(5)</u>**.

* **Sec. 20.** AS 43.82.445(b) - (d) are repealed.

* **Sec. 21.** The uncodified law of the State of Alaska is amended by adding a new section to read:

REVISOR'S INSTRUCTION. The revisor of statutes is instructed to change the section heading of AS 43.82.220 from "Contract terms relating to royalty" to "Contract terms relating to oil and gas lease, royalty provisions, and other agreements."

* **Sec. 22**. The uncodified law of the State of Alaska is amended by adding a new section to read:

RETROACTIVITY. (a) Sections 1 - 18 and 20 of this Act are retroactive to January 1, 2004.

(b) Section 19 of this Act is retroactive to January 1, 2005.

* **Sec. 23.** This Act takes effect immediately under AS 01.10.070(c).