

HB

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**ALASKA LNG MIDSTREAM SERVICES
PRECEDENT AGREEMENT**

THIS PRECEDENT AGREEMENT is entered into as of this 9th day of June, 2014 (the “**Effective Date**”).

PARTIES:

TRANSCANADA ALASKA MIDSTREAM LP
a Delaware limited partnership (“**Transporter**”)

AND

THE STATE OF ALASKA,
acting in its proprietary capacity as owner of the State Gas Share
 (“**Shipper**”).

RECITALS:

- A. On January 14, 2014, TADI, the State, AGDC and Affiliates of the Producer Parties (the “**HOA Parties**”) entered into a Heads of Agreement (“**HOA**”) which outlined the general principles governing the development of the Alaska LNG Project and related matters;
- B. As set forth in the HOA, the Producer Parties desire for the State to participate in the Alaska LNG Project by accepting the State Gas Share, and thereby participating with an ownership interest in the Alaska LNG Project commensurate with the percentage that the State Gas Share represents as a portion of the total natural gas flow from the Point Thomson Unit and the Prudhoe Bay Unit as reflected in the Key Project Agreements (as may be adjusted from time to time in accordance therewith, the “**Shipper Percentage**”), with the intent that the State or its designees will hold a percentage ownership interest in the Alaska LNG Project equal to the Shipper Percentage;
- C. The State selected TADI (now succeeded by its Affiliate, Transporter) to hold (in Transporter’s name) the Shipper Percentage of the equity in the Midstream Facilities of the Alaska LNG Project. Accordingly, on December 12, 2013, TADI, TC Alaska, Foothills (collectively the “**TC MOU Parties**”) and the State entered into a Memorandum of Understanding regarding the Alaska LNG Project, as clarified by the Letter of Clarification to Memorandum of Understanding, executed April 4, 2014 (collectively, the “**MOU**”);
- D. On May 8, 2014, the Enabling Legislation, as defined in the MOU, was signed into law and the provisions relevant to the MOU became effective, which Enabling Legislation is acceptable to the TC MOU Parties and the State;
- E. Pursuant to and in accordance with the MOU, TADI, through Affiliates, formed Transporter to allow Transporter, as TADI’s Affiliate, to acquire a participation interest in the Pre-FEED JVA and the FEED Agreement, and to acquire an equity participation interest in the Midstream Facilities equal to the Shipper Percentage to provide the Services to Shipper (the actual corporate structure of the Alaska LNG Project and Transporter’s equity participation interest in the Midstream Facilities are to be agreed upon by the parties to the Pre-FEED JVA and the State and finalized during the Pre-FEED process);

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- F. In order for the Parties to participate in the Pre-FEED and FEED process and to ultimately participate with the Alaska LNG Parties to make a positive FID in respect of the Midstream Facilities, the Parties acknowledge their mutual interests in furthering the development of the Midstream Facilities as part of the Alaska LNG Project; and
- G. In furtherance of the foregoing, the Parties desire to enter into this PA (which in all respects supersedes and replaces Exhibit C to the MOU) that sets forth the terms upon which the Parties will develop and enter into the FTSA.

NOW THEREFORE the Parties agree as follows:

**ARTICLE 1
DEFINITIONS AND INTERPRETATION**

1.1 Definitions

Whenever used in this PA, capitalized terms used will have the meanings set out in section 1 of Schedule A. The rules of interpretation set out in section 2 of Schedule A will apply to this PA.

1.2 Schedules

The schedules to this PA, as listed below, are an integral part of this PA:

<u>Schedule</u>	<u>Description</u>
A	Definitions and Interpretation
B	FTSA Terms
C	Negotiated Rate Principles
D	Creditworthiness Requirements
E	Audit Protocol
F	Transporter Conveyance Mechanics
G	Illustrative FTSA Table of Contents

**ARTICLE 2
PROJECT DEVELOPMENT PROCESS**

2.1 Pre-FEED Process and FTSA Development Process

The Parties agree that the process for development and execution of the FTSA as contemplated by this PA shall proceed in the following manner:

- (a) Promptly following the Effective Date, in the event the Pre-FEED JVA has not been executed, the Parties shall take reasonable commercial steps to finalize the Pre-FEED JVA. Upon agreement upon the terms of the Pre-FEED JVA by the State and the parties thereto (including Transporter), and execution of the Pre-FEED JVA by the Producer Parties and AGDC, Transporter will execute and deliver the Pre-FEED JVA simultaneously with the execution and delivery of the Pre-FEED JVA by the other parties thereto.

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- (b) Commencing promptly following the Effective Date and proceeding with reasonable dispatch, the Parties shall:
 - (i) Negotiate and seek to agree upon the final terms of the FTSA, as described in Section 2.2;
 - (ii) Determine the final contractual and regulatory structure applicable to the Midstream Facilities provision of the Services by Transporter to Shipper and such other shippers in such manner as the Parties may agree, acting reasonably, as described in Section 2.3;
 - (iii) Consult with each other in the establishment of the material provisions pertaining to the development, operation (including access to), and expansion of the Midstream Facilities to be contained in the Key Project Agreements;
 - (iv) Participate in the development of the definitive FEED Agreement and the other Key Project Agreements with a view to advancing the Alaska LNG Project to FEED and to FID; and
 - (v) Upon agreement pursuant to Section 2.2, submit to the State Legislature for approval (1) the FTSA, and (2) the FTSA Legislation, and shall support the approval of the FTSA Legislation.
- (c) Upon satisfaction of the conditions precedent set forth in ARTICLE 3 and provided this PA has not expired pursuant to Section 4.1(a) or been earlier terminated, the Parties shall execute the FTSA.

2.2 FTSA Terms

All of Section 2.2 is commercially sensitive for TransCanada and has been redacted on the basis that the State of Alaska intends to issue a Notice of Termination to TransCanada Alaska Midstream LP once an appropriation to pay TransCanada has been approved. In such case there will be no FTSA and so this Section 2.2 is not relevant.

2.3 Regulatory Strategy and Structure

- (a) Using reasonable efforts with due diligence and good faith, and pursuant to the process in Section 5.2, Transporter and Shipper shall seek to determine the appropriate strategy, in consultation with the appropriate regulatory agencies, where appropriate, in respect of Regulatory Approvals to be obtained by or on behalf of Transporter or Shipper (in their capacities as such) to allow Transporter to provide the Services as contemplated by the FTSA Terms. The strategy shall consider and incorporate, among other things, the appropriate regulatory regime and the terms of any service rules and regulations, if applicable.
- (b) The Parties agree that the intent of any such strategy, regime or regulatory structure is to be consistent with the following:
 - (i) the Pre-Construction Regulatory Approvals process for the Alaska LNG Project as a whole as reflected in the Key Project Agreements, including Article 6 of the HOA;

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- (ii) the process and schedule for (1) the Pre-FEED and FEED processes, (2) FID, and (3) construction and operation of the Midstream Facilities as determined in connection with the Alaska LNG Project as a whole as reflected in the Key Project Agreements; and
 - (iii) the FTSA Terms, the Negotiated Rate Principles, and the Creditworthiness Requirements.
- (c) In any consultation with FERC or other applicable regulatory agency in connection with the foregoing, Transporter will be the lead party for Transporter and Shipper as the primary point of communication with FERC or such other regulatory agency for the provision of Services by Transporter in respect of the Midstream Facilities (in coordination with the Pre-FEED JVA Parties, if necessary), and Shipper may participate in such communications. Nothing herein limits in any way Shipper's ability to meet and discuss issues with FERC or other applicable regulatory agencies in furtherance of its interests, including its interests (i) as a sovereign in its capacity as the State, (ii) as a shipper, and (iii) as an Affiliate of AGDC with respect to the LNG Plant. Transporter and Shipper agree that any such communications and discussions will be consistent with the terms of this PA, including the framework and agreements between the Parties pursuant to this Section 2.3.
- (d) Transporter and Shipper shall coordinate the preparation of the applications to secure the primary Regulatory Approvals in respect of the Services in conjunction with the operation of the Coordination Committee. Shipper expressly agrees to cooperate with the efforts of Transporter to obtain any such Regulatory Approvals sought by Transporter pursuant to and in accordance with Section 2.3, including providing any information that is reasonably requested by Transporter in preparing applications or prosecuting applications for such Regulatory Approvals. Shipper agrees not to appeal any such Regulatory Approvals which are issued substantially on the terms initially applied for and which are consistent with this PA, the FTSA (and FTSA Terms), the HOA and the Key Project Agreements and those items determined pursuant to Section 2.3(b) for the term of the FTSA and as considered by the Coordination Committee, unless Shipper is of the reasonable opinion that any provision or condition of such Regulatory Approvals which varies from or is in addition to the provisions or conditions initially applied for may have a material adverse effect on Shipper.

2.4 Creditworthiness Requirements

- (a) During the term of this PA and the term of the FTSA, Shipper shall establish and maintain its creditworthiness in accordance with the Creditworthiness Requirements.
- (b) Immediately prior to (i) execution of the FTSA, and (ii) FID, as reasonably requested by Shipper, Transporter shall demonstrate to Shipper's reasonable satisfaction that Transporter has provided (or is capable of providing) any required financial assurances in accordance with the Key Project Agreements.

2.5 State Shipper Requirements

For greater certainty for purposes of this PA and the FTSA (including the FTSA Terms), the following provisions shall only apply to Shipper where Shipper is the State Shipper: Section 2.3 (Regulatory Strategy and Structure), Section 4.4 (Conveyance of Transporter Alaska LNG Project Interest to Shipper), Section

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5.1 (Alaska LNG Project Information), Section 5.2 (Coordination Committee), Section 5.3 (Development Costs Approval), parts 4 and 5 of Schedule B (Buy-Back Right and Put Option), parts 17-19 of Schedule B (Expansions), and Schedule F (Transporter Conveyance Mechanics).

ARTICLE 3 CONDITIONS PRECEDENT

3.1 Shipper's Conditions Precedent

Shipper's obligation to execute the FTSA is subject to the satisfaction or written waiver (in its sole discretion) of the following conditions precedent within the time frames specified (each, a "**Shipper Condition**"):

- (a) **FTSA Legislation:** on or before the FTSA Decision Date the FTSA Legislation has become effective on terms satisfactory to Shipper in its sole discretion;
- (b) **Key Project Agreements:** the State and the Producer Parties shall have negotiated Key Project Agreements that, in Shipper's sole discretion, are sufficient for Shipper to make a State Gas Share determination; and
- (c) **Transporter Performance under this PA:**
 - (i) a Default Event of Transporter shall not have occurred and remain uncured; and
 - (ii) Shipper has received evidence (satisfactory to Shipper in its sole discretion) that Transporter has satisfied or waived the Transporter Conditions; and

The conditions precedent stated in this Section 3.1 are included for the sole benefit of Shipper and may only be waived by Shipper. Subject to Shipper's obligations in respect of the Termination Amount pursuant to Section 4.3, Shipper shall have no other liability whatsoever to Transporter in the event that any or all of the Shipper Conditions are not satisfied.

3.2 Transporter's Conditions Precedent

Transporter's obligation to enter into the FTSA is subject to the satisfaction or express waiver (in its sole discretion) of the following conditions precedent within the time frames specified (each, a "**Transporter Condition**"):

- (a) **FTSA Legislation:** on or before the FTSA Decision Date the FTSA Legislation has become effective on terms satisfactory to Transporter in its sole discretion;
- (b) **Shipper Performance under this PA:**
 - (i) a Default Event of Shipper shall not have occurred and remain uncured (including in respect of the Creditworthiness Requirements); and
 - (ii) Transporter shall have received evidence (satisfactory to Transporter in its sole discretion) that Shipper has satisfied or has waived the Shipper Conditions.

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The conditions precedent stated in this Section 3.2 are included for the sole benefit of Transporter and may only be waived by Transporter. Transporter shall have no liability whatsoever to Shipper in the event that any or all of the Transporter Conditions are not satisfied.

**ARTICLE 4
TERM AND TERMINATION**

4.1 Term

The PA shall become effective as of the Effective Date and shall remain in effect, subject to Shipper's or Transporter's exercise of rights pursuant to Section 4.2 until the earliest to occur of the following (the "**Expiry Date**") (at which time this PA shall expire automatically without further action by either of the Parties):

- (a) the date that is one day prior to the second anniversary of the Effective Date; and
- (b) the Parties' execution of the FTSA, which, by its terms, will supersede and replace this PA.

4.2 Termination

This PA may be terminated prior to the Expiry Date as follows:

- (a) **Termination by Shipper:** Upon the delivery by Shipper to Transporter of a Notice of termination in the event that:
 - (i) the term(s) of the Key Project Agreements to which Shipper or its Affiliate is a party, is/are not acceptable to Shipper in its sole discretion;
 - (ii) each of (1) AGDC, (2) Transporter, and (3) one or more of the Producer Parties, have not executed the Pre-FEED JVA on or before November 30, 2014, or such later date agreed to by the Parties;
 - (iii) on or before the FTSA Decision Date, Transporter fails to execute the FTSA (including failure by the Parties to agree to the terms of the FTSA);
 - (iv) prior to a positive FEED Decision, Shipper elects, in its sole discretion, to terminate 90 days from providing Notice of termination to Transporter;
 - (v) any final Regulatory Approvals include material unacceptable condition(s) or requirement(s) to Shipper in its sole discretion, provided that such Notice is delivered within 90 days from the date of issuance of such Regulatory Approval;
 - (vi) the Pre-FEED JVA is (1) terminated prior to the expiry of the Pre-FEED JVA for any reason other than entry into the FEED Agreement, or (2) expires without a FEED Decision;
 - (vii) Transporter withdraws from the Pre-FEED JVA;
 - (viii) Any one or more of the Shipper Conditions have not been satisfied or waived within the time frame specified (or such later date as Shipper may agree), or if no time frame is specified, on or before the FTSA Decision Date; or

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- (ix) a Default Event of Transporter occurs, as set out in Section 6.1.
- (b) **Termination by Transporter:** Upon delivery by Transporter to Shipper of a Notice of termination in the event that:
 - (i) the term(s) of the Key Project Agreements to which Transporter or its Affiliate is a party, is/are not acceptable to Transporter in its sole discretion;
 - (ii) each of (1) AGDC, (2) Transporter, and (3) one or more of the Producer Parties, have not executed the Pre-FEED JVA on or before November 30, 2014, or such later date agreed to by the Parties;
 - (iii) on or before the FTSA Decision Date, Shipper fails to execute the FTSA (including failure by the Parties to agree to the terms of the FTSA);
 - (iv) any final Regulatory Approvals include material unacceptable condition(s) or requirement(s) to Transporter in its sole discretion, provided that such Notice is delivered within 90 days from the date of issuance of such Regulatory Approval;
 - (v) the Pre-FEED JVA is (1) terminated prior to the expiry of the Pre-FEED JVA for any reason other than entry into the FEED Agreement, or (2) expires without a FEED Decision;
 - (vi) any one or more of the Transporter Conditions have not been satisfied or waived within the time frame specified (or such later date as Transporter may agree), or if no time frame is specified, on or before the FTSA Decision Date; or
 - (vii) upon the occurrence of any of the following:
 - 1) Shipper fails to approve a Revised Transporter Estimate pursuant to Section 5.3(b)(iii);
 - 2) a Default Event of Shipper occurs, as set out in Section 6.3; or
 - 3) Transporter provides Notice to Shipper of its intent to terminate this PA pursuant to Section 7.4(d).

4.3 Payment of Termination Amount

- (a) In the event of (i) expiry of this PA pursuant to Section 4.1(a), or (ii) termination of this PA for any reason pursuant to Section 4.2, Shipper shall pay Transporter an amount equal to the Development Costs for the period up to and including the Termination Date. (collectively, all amounts calculated pursuant to and in accordance with this Section 4.3(a) are the “**Development Cost Amount**”).
- (b) If this PA:
 - (i) expires pursuant to Section 4.1(a);
 - (ii) is terminated pursuant to Section 4.2 as a result of any of the following events:

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- 1) by Shipper pursuant to Section 4.2(a) (except in the event of a Default Event of Transporter pursuant to Section 4.2(a)(ix));
- 2) by Transporter pursuant to (A) Section 4.2(b)(vii) (Shipper-initiated Transporter termination), or (B) Section 4.2(b)(vi) resulting from a failure of the Transporter Condition in Section 3.2(a) (FTSA Legislation) or Section 3.2(b) (Shipper Performance), then

in addition to the Development Cost Amount, Shipper shall further pay interest to Transporter calculated in accordance with the Carrying Cost Calculation (collectively, all amounts payable by Shipper to Transporter as calculated pursuant to Section 4.3(a) and this Section 4.3(b) are the "**Termination Amount**").

- (c) Upon delivery of a Notice of termination for a termination event described in Section 4.3(a):
 - (i) Transporter shall deliver to Shipper within 30 days a final report of the Termination Amount as of the Termination Date, together with reasonable supporting documentation thereof (collectively, "**Termination Amount Notice**").
 - (ii) Upon request by Shipper (and no later than 10 days following receipt of such request), Transporter must provide information reasonably requested by Shipper concerning specific elements forming part of the Development Costs as part of Termination Amount, including supporting documentation and justification.
 - (iii) Not later than 30 days following receipt of the Termination Amount Notice, Shipper shall either (1) pay the Termination Amount, or (2) provide Notice to Transporter in reasonable detail of any objection to the Termination Amount, identifying those amounts forming part of the Termination Amount objected to and presenting an alternate Termination Amount (the "**Termination Amount Objection**"). For greater certainty, Shipper shall be restricted from objecting to any amounts forming part of the Termination Amount that have been deemed to be Prudent Costs pursuant to the terms of this PA.
 - (iv) If Shipper has delivered a Termination Amount Objection and the Parties fail to agree upon the Termination Amount within 5 Business Days following Transporter's receipt of the Termination Amount Objection, then either Party may provide Notice to the other of its intent to commence the Dispute Resolution Procedure in respect of such Dispute, and
 - 1) Shipper shall make payment in full of the Termination Amount as specified in the Termination Amount Notice within 5 Business Days of the Notice of intent to commence the Dispute Resolution Procedure; and
 - 2) Transporter shall be entitled to receive and retain all undisputed portions of the Termination Amount, and any disputed amounts of the Termination Amount shall be paid into escrow in a trust account pending resolution of the Dispute pursuant to the Dispute Resolution Procedure. Upon resolution of the disputed portion of the Termination Amount, Transporter shall: (i) return such part of the disputed portion to the Shipper in the amount

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ultimately resolved in its favor, and/or (ii) transfer such part of such disputed portion to Transporter in the amount ultimately resolved in its favor. Interest earned on the Trust account shall be distributed *pro rata* with the distribution of the disputed amount as ultimately resolved.

- (v) Shipper shall pay interest at a rate of interest equal to the Agreed Interest Rate, on any amount outstanding after the payment due date pursuant to this Section 4.3(c), commencing on either:
 - 1) where this PA has been terminated by Transporter pursuant to Section 4.2(b), on the date that is 90 days after such payment due date (provided that interest shall continue to accrue on the outstanding amounts at an annual rate of interest equal to 7.1% compounded monthly and accruing daily prior to such 90th day); and
 - 2) in all other instances, on such payment due date.
- (d) Shipper's obligation to reimburse Transporter for the Termination Amount and pay Transporter any interest amounts payable pursuant to this Section 4.3 shall be Transporter's exclusive remedy in law and equity in the event this PA expires or terminates; provided however, in the event that Transporter is unable to enforce such obligation of Shipper, Transporter shall be entitled to assert all claims available to it at law or in equity to recover the Termination Amount. Subject to the foregoing, nothing herein is intended to affect Transporter's rights under Section 6.4 governing a Default Event of Shipper.
- (e) Shipper covenants that it will make all required appropriations requests from the Alaska Legislature in respect of the Termination Amount and take all reasonable commercial efforts to have all such appropriation requests approved by the Alaska Legislature.
- (f) Shipper's obligation to make payments pursuant to this Section 4.3 shall survive any expiration or termination of this PA until all such amounts owed by Shipper have been paid in full.

4.4 Conveyance of Transporter Alaska LNG Project Interest to Shipper

Upon a Termination Event and payment in full to Transporter of the Termination Amount and any interest amounts payable pursuant to Section 4.3, Transporter shall convey (or shall cause to be conveyed) the interests to Shipper (or its designee Affiliate) in accordance with the Transporter Conveyance Mechanics.

4.5 Survival

In the event this PA expires pursuant to Section 4.1(a) or is terminated pursuant to Section 4.2, the following Sections shall survive and shall continue to be of full force and effect for such period as necessary to give effect thereto: Article 1 (Definitions and Interpretation), Section 4.3 (Development Cost Reimbursement), Section 4.4 (Conveyance of Transporter Alaska LNG Project Interest to Shipper), Section 7.2 (Limitation of Liability), Section 7.1 (Confidentiality Agreement), Section 7.6 (Governing Law) and Section 7.7 (Dispute Resolution).

ARTICLE 5
PROJECT DEVELOPMENT COOPERATION

5.1 Alaska LNG Project Information

- (a) In order to provide timely access to Shipper to material and relevant information relating to the development of the Midstream Facilities (collectively, "**Project Information**"), including (1) draft Key Project Agreements to which Transporter is or will be a Party, (2) information relating to all activities, design basis, and regulatory progress, and (3) quarterly progress reports including spend to date and schedule updates, that Transporter receives in its capacity as an equity participant in the Alaska LNG Project, Transporter will provide Shipper with the Project Information in a manner mutually agreeable to both Parties. Notwithstanding the foregoing, Transporter's obligation to include specific Project Information (and Shipper access to such Project Information) shall be subject to (and limited by) Governmental Requirements and any confidentiality restrictions contained in the applicable Project Agreements to which Transporter is a Party.
- (b) Shipper use of any information provided pursuant this Section 5.1 shall be subject to any confidentiality restrictions arising from Section 7.1 and the Project Agreement(s) to which such information arises.

5.2 Coordination Committee

- (a) To provide for the overall supervision and direction of, and strategic guidance with respect to, the development of the Midstream Facilities and the matters described in Section 2.1, a coordination committee shall be established and maintained during the term of this PA (the "**Coordination Committee**").
- (b) The Coordination Committee will consist of at least two representatives of each Party (as designated by Notice to the other Party, each such designated representative for a Party, a "**Nominee**"). The Nominees, acting reasonably, will seek to reach consensus on all decisions, directions and other matters on which the Coordination Committee takes action under this PA.
- (c) The Coordination Committee shall meet at agreed upon times (not less than once per month for the period prior to FID, and not less than quarterly thereafter) to carry out its mandate. The Parties will work to schedule such meetings prior to each meeting of a Key Project Agreement governing body meeting concerning the Midstream Facilities or Integrated Matters, to determine whether the Parties have, or can reach, a common position on issues to be addressed at such governing body meetings (including in respect of any WP&B as contemplated by Section 5.3(a)). The agenda for any Coordination Committee meeting shall be distributed to the Nominees in advance of any such meeting. At the time of a meeting, items may be added to the agenda for that meeting only as the Coordination Committee may approve. All meetings shall be held at locations to be agreed upon by the Nominees and such meetings may be held by video conference or teleconference, as proposed by a Party by Notice to the other Party.
- (d) To the extent any issues relating to Project Information (not including WP&B approval pursuant to Section 5.3(a)) have not been resolved to Shipper's satisfaction at the applicable meeting of the Coordination Committee, then upon Notice from Shipper of any

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remaining concerns with any Project Information, Transporter will act in good faith to raise and seek to resolve Shipper's concern through the applicable various committees established pursuant to the Key Project Agreements to which Transporter is a Party. Should Shipper's concern still not be resolved to Shipper's satisfaction, then Transporter will consider Shipper's outstanding concern when exercising its voting discretion on related matters before such committees. Transporter will advise the Shipper of its position with respect to the outstanding Shipper concern prior to any such vote.

5.3 Development Costs Approval

(a) *AKLNG Development Costs:*

- (i) On a timely basis after receipt thereof by Transporter pursuant to the Pre-FEED JVA or the FEED Agreement (as applicable), Transporter will provide Shipper with Notice of the then-applicable WP&B including a copy of the proposed WP&B ("**WP&B Notice**") for Shipper review and approval of the proposed WP&B. The WP&B Notice shall include reference to the date for approval or rejection of such WP&B by Transporter ("**WP&B Decision Date**") in its capacity as equity or participating interest holder in the Midstream Facilities in accordance with the established WP&B approval protocol in the applicable Key Project Agreements, including the Pre-FEED JVA and the FEED Agreement. The Parties acknowledge that the initial WP&B for the Pre-FEED JVA [REDACTED] is deemed to be approved by Shipper.
- (ii) Not later than five (5) Business Days prior to the WP&B Decision Date (the "**Shipper Decision Date**") Shipper shall provide Transporter with Notice ("**Shipper WP&B Notice**") of its determination whether such WP&B should be approved or rejected by Transporter, together with, in the case of rejection, supporting reasons for such rejection.
- (iii) If Shipper has provided Transporter with the Shipper WP&B Notice by the Shipper Decision Date, Transporter shall vote (as part of the approval process under the applicable Key Project Agreement) in accordance with the election of Shipper contained in the Shipper WP&B Notice. If the Shipper WP&B Notice indicates a rejection of such WP&B, Transporter shall raise the concern described in the Shipper WP&B Notice in connection with the exercise of such vote.
- (iv) In the event Shipper does not provide the Shipper WP&B Notice to Transporter by the Shipper Decision Date, Transporter shall be entitled to exercise its vote whether to approve or reject such WP&B in its sole discretion.
- (v) Notwithstanding Section 5.3(a)(iii), Transporter shall not be obliged to vote not to approve a WP&B where Shipper has elected to reject such WP&B if failure by Transporter to approve such WP&B would result (or be reasonably likely to result) in either a breach by, or default of, Transporter of the applicable agreement giving rise to the WP&B or an acceleration of any material obligations of Transporter pursuant to such agreement.

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(b) **Transporter Development Costs:**

- (i) Promptly following the Effective Date and not later than ["120 days following the Effective Date" charged to "November 18, 2014" by amendment], the Parties shall agree upon a budget (including contingencies and applicable allocations of overhead components) for Transporter Development Costs for the period from the Effective Date to the Expiry Date (the total agreed budgeted amount is the "**Transporter Authorized Amount**"). Upon such agreement, Shipper acknowledges and accepts that the Transporter Authorized Amount is not a firm estimate, quotation or price, but only an estimate of the Transporter Development Costs to such date.
- (ii) If at any time Transporter reasonably anticipates that the Transporter Authorized Amount in effect at such time will be exceeded, Transporter shall provide Notice to Shipper containing reasonable details of such anticipated additional expenditures and its revised estimate in respect of the total Transporter Authorized Amount (the "**Revised Transporter Estimate**"). Transporter shall provide, upon the reasonable request of Shipper, such additional details and information as may be reasonably required in respect of such Revised Transporter Estimate.
- (iii) Shipper shall provide Notice to Transporter within ten (10) Business Days of its receipt of a Revised Transporter Estimate whether it approves or rejects the Revised Transporter Estimate. Upon approval of a Revised Transporter Estimate (as may be amended by agreement of the Parties), such Revised Transporter Estimate shall constitute the Transporter Authorized Amount unless and until further revised in accordance with this Section 5.3(b). If Shipper fails to approve a Revised Transporter Estimate within such time frame, Transporter shall have a right to terminate this PA in accordance with Section 4.2(b)(vii)1).
- (iv) Nothing contained in this Section 5.3(b) shall restrict Transporter's rights to make expenditures necessary and proper for the protection of life, health, the environment and property in the case of an emergency without Shipper's approval; provided, however, that Transporter shall immediately notify Shipper of the details of such emergency, the measures taken and the estimated costs. All such actual costs shall constitute part of the Transporter Authorized Amount in addition to the Transporter Authorized Amount in effect at such time (subject to audit in accordance with the Audit Protocol).

(c) **Prudent Costs:** All costs and expenses that have actually been incurred and that are:

- (i) approved or deemed approved by Shipper or any Affiliate pursuant to this Section 5.3 (including any portion forming part of the Transporter Authorized Amount); or
- (ii) pursuant to or in connection with a WP&B approved by the applicable Alaska LNG Parties (and in effect) under any Key Project Agreement (including where Transporter has voted to reject such WP&B pursuant to Section 5.3(a)(iii)),

shall be Prudent Costs for all purposes under this PA and the FTSA.

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**ARTICLE 6
EVENTS OF DEFAULT**

6.1 Default Events of Transporter

The following constitute Default Events of Transporter for the purposes of this PA:

- (a) an Insolvency Event occurs in relation to Transporter (unless any such Insolvency Event was caused, directly or indirectly, by a failure on the part of Shipper or any Affiliate of Shipper as a Limited Partner of Transporter to advance funds in connection with a cash call related to a requirement to advance funds under a Project Agreement); and
- (b) Transporter defaults in the performance or observance of any material covenant, obligation or condition to be observed or performed by it pursuant to this PA and does not remedy such default (if reasonably remediable) within 30 days of having received a default Notice advising Transporter to do so from Shipper or if not reasonably remediable within such 30-day period, fails to commence to remedy within such 30-day period and thereafter to proceed diligently and as expeditiously as possible to do so within a reasonable schedule agreed to by Shipper, acting reasonably.

6.2 Shipper Remedies

If a Default Event of Transporter occurs, Shipper may pursue such remedies available to it at law or in equity, including for direct damages suffered by Shipper, injunctive relief and specific performance, as appropriate.

6.3 Default Events of Shipper

The following constitute Default Events of Shipper for the purposes of this PA:

- (a) an Insolvency Event occurs in relation to Shipper or its Credit Support Provider;
- (b) Shipper fails to maintain the Creditworthiness Requirements and fails to remedy such default within the relevant time frame specified in paragraph 5 of Schedule D; and
- (c) Shipper defaults in the performance or observance of any other material covenant, obligation or condition to be observed or performed by Shipper pursuant to this PA and does not remedy such default (if reasonably remediable) within 30 days of having received a Default Notice from Transporter advising Shipper to do so, or if not reasonably remediable within such 30-day period, fails to commence to remedy within such 30-day period and thereafter to proceed diligently and as expeditiously as possible to do so within a reasonable schedule agreed to by Transporter, acting reasonably.

6.4 Transporter Remedies

If a Default Event of Shipper occurs, subject to the limitations contained in Section 4.3(d) in respect of payment of the Termination Amount upon expiration or termination of this PA, Transporter may pursue

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such remedies available to it at law or in equity, including for direct damages suffered by Transporter, injunctive relief and specific performance, as appropriate.

ARTICLE 7 MISCELLANEOUS

7.1 Confidentiality Agreement

Except to the extent expressly set forth to the contrary herein, this PA and all information generated and/or exchanged by the Parties pursuant to this PA shall be deemed to be Confidential Information subject in all respects to the Confidentiality Agreement, and all matters relating to this PA fall within the scope of "Discussions" as defined in the Confidentiality Agreement. The provisions of this Section 7.1 shall survive the termination of this PA and the assignment by a Party and its Affiliates of all of their interests in this PA prior to termination of this PA for the period specified in the Confidentiality Agreement.

7.2 Limitation of Liability

- (a) Under no circumstances shall:
 - (i) Transporter and its Affiliates and their respective directors, stockholders, officers, employees, agents, consultants, representatives, successors, transferees and assigns, or
 - (ii) Shipper and its Affiliates and their respective directors, stockholders, officers, employees, agents, consultants, representatives, successors, transferees and assigns,

be liable to the other Party (or any other Person claiming by through or under such other Party) for any Consequential Losses.

- (b) Transporter (and its Affiliates and their respective directors, stockholders, officers, employees, agents, consultants, representatives, successors, transferees and assigns) is not liable to Shipper (and its Affiliates and their respective directors, stockholders, officers, employees, agents, consultants, representatives, successors, transferees and assigns) for any Losses (howsoever caused and whether contractual or tortious), asserted against or suffered or incurred by the Shipper (or its Affiliates and their respective directors, stockholders, officers, employees, agents, consultants, representatives, successors, transferees and assigns), or any of them, except and to the extent that such Losses are caused by Gross Negligence or Wilful Misconduct, subject to any applicable restrictions binding upon Shipper under Alaska law as of the Effective Date in relation to any agreements surrounding the foregoing.

7.3 Mutual Representations and Warranties

Each Party represents and warrants to the other Party that:

- (a) **Organization, Qualification, and Corporate Power:** In the case of Transporter, it is duly organized or formed, validly existing, and in good standing under the laws of the jurisdiction of its organization or formation, and has all requisite power and authority to

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own, lease, and operate its assets and to carry on its businesses as they are now being conducted.

- (b) **Authorization of Transactions; Validity and Enforceability:** It has all requisite power and authority to enter into this PA, to perform its obligations hereunder, and to consummate the transactions contemplated hereby. The execution, delivery, and performance by it of this PA and the consummation by it of the transactions contemplated by this PA have been duly authorized by all necessary statutory, administrative, or corporate or partnership action or other action (as applicable) on the part of it. This PA has been duly executed and delivered by such Party. and, assuming the due authorization, execution, and delivery hereof by the other Party, constitutes a legal, valid, and binding obligation of it enforceable against it in accordance with its terms, except as such enforceability may be affected by: (i) applicable bankruptcy, reorganization, insolvency, moratorium, and other laws and court decisions of general application, including statutory and other laws regarding fraudulent or preferential transfers relating to, limiting, or affecting the enforcement of creditors' rights generally; and (ii) general principles of equity, including the effect of such general principles of equity upon the specific enforceability of any of the remedies, covenants, or other provisions contained herein and therein, and their application (regardless of whether enforcement is considered in a proceeding at law or in equity) as such principles relate to, limit, or affect the enforcement of creditors' rights generally, and provided that Transporter makes no representation and warranty as to the effect of Chapter 14 SLA 14 (also known as Senate Bill 138).
- (c) **Non-contravention; Consents and Approvals:** The execution and delivery by it of this PA, the consummation of the transactions contemplated by this PA, and the performance of the obligations of such Party hereunder will not conflict with, or result in any violation of or default under, any provision of any governing instrument applicable to such Party, or any agreement or other instrument to which such Party is a party or by which such Party (and in the case of a partnership each of its partners) or any of its assets is bound, or any Governmental Requirement or other law applicable to such Party, its assets, or to this PA.

7.4 Discriminatory Changes in Law

- (a) If the State enacts or amends (or is proposing to enact or amend) any Governmental Requirement in such a manner as to create a discriminatory adverse effect on Transporter (including any discriminatory adverse change to or effect on the assets, business operations or financial condition of the Transporter or its Affiliates) or any Midstream Facility (a "**Discriminatory Change in Law**"), then either Party may provide Notice to the other to express an opinion on its likely effects, giving details of its opinion of:
 - (i) any necessary change in the Services;
 - (ii) whether any changes are likely or required to the terms of this PA or the FTSA to deal with the effects of the Discriminatory Change in Law; and
 - (iii) whether relief from compliance with obligations is required during the implementation of any relevant Discriminatory Change in Law, including any loss of revenue or increase in costs (including Development Costs) that will result from the relevant Discriminatory Change in Law.

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- (b) As soon as practicable after receipt of any Notice pursuant to Section 7.4(a) from either Party, the Parties shall discuss the issues referred to in such Notice and:
 - (i) any ways in which Transporter can mitigate the effect of the Discriminatory Change of Law; and
 - (ii) the Parties will diligently and in good faith seek to renegotiate the terms of this PA and/or the FTSA to comply with such Discriminatory Change of Law and in accordance with the initial expectations of the Parties under this PA; provided, however, that the Parties recognize that discussion of the issues referred to in such Notice shall not constitute an admission by either Party that (i) there has been a Discriminatory Change in Law, or (ii) that a Party has an obligation to amend this PA.
- (c) Upon the occurrence of the Discriminatory Change in Law and subject to Transporter's reasonable commercial efforts to mitigate such Discriminatory Change in Law, and failing agreement of the Parties under Section 7.4(b)(ii) as to any modifications to this PA and/or the FTSA, then to the extent that:
 - (i) such Discriminatory Change of Law prevents Transporter from complying with any of its obligations under this PA or the FTSA, such failure to comply with that obligation shall be deemed not to be a breach of the applicable agreement;
 - (ii) as a non-remote result of the Discriminatory Change in Law:
 - 1) there is any increase in costs borne by Transporter in connection with the Midstream Facilities that would not otherwise be included in the Annual Reservation Charge as Annual Fixed O&M Expenses or Taxes Other Than Income Taxes in accordance with the Negotiated Rate Principles contained in Schedule C, then from and after the effective date of such Discriminatory Change in Law, such increased costs shall be incorporated into the Annual Reservation Charge to the account of Shipper; and
 - 2) any capital modifications are required to be made to any of the Midstream Facilities, the associated costs shall be borne by Shipper as an incremental capital cost in accordance with the Negotiated Rate Principles.

For greater certainty, such incremental costs shall be subject to audit in accordance with the Audit Protocol.
- (d) If Transporter reasonably determines that a Discriminatory Change of Law has occurred and its rights (including reasonable economic expectations) have been materially adversely effected that cannot be mitigated on reasonable commercial terms pursuant to Section 7.4(c), then Transporter shall have the right to terminate this PA pursuant to Section 4.2(b)(vii)3, or the FTSA pursuant to the equivalent provisions thereof.

7.5 Notices

- (a) Whenever this PA requires or permits any notice (each, a "**Notice**") to be given to any Party or any other Person, such Notice must be in writing and must be delivered in person

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or by courier or electronic mail. A Notice will be deemed given when the Person to which it is addressed receives it; provided, however, that electronic mail if sent with an automatic delivery receipt received and retained which is transmitted after the normal business hours of the recipient will be deemed given on the next Business Day unless the recipient has in fact acknowledged its earlier receipt. All Notices to a Party must, if not delivered in person, be sent to the address for that Party which Section 7.5(b) specifies or at such other address as that Party has specified by Notice to the other Party. Oral communication does not constitute Notice for purposes of this PA, and telephone numbers for the Parties are listed below as a matter of convenience only.

- (b) This Section 7.5(b) includes initial contact information, including e-mail addresses and telephone numbers, for each Party. A Party may change its contact information from time to time by Notice to the other Party.

Transporter

Address: c/o TransCanada Alaska GP Inc.
450 – 1st Street SW
Calgary, AB T2P 5H1
Canada

Attention: President

Telephone No. 832-320-5655
E-mail Address dean_patry@transcanada.com

with a copy to:

Address: 717 Texas Street, Suite 2400
Houston, TX 77002

Attention: Corporate Secretarial

Telephone No. 832-320-5201
E-mail Address jon_dobson@transcanada.com

Shipper

Address: State of Alaska
Department of Natural Resources
550 W. 7th. Avenue, Suite 1400
Anchorage, AK 99501

Attention: Commissioner Joe Balash

Telephone No. 907-269-8431
E-mail Address joe.balash@alaska.gov

Whenever any Notice is required to be given under the provisions of this PA, a waiver thereof in writing signed by the Person or Persons entitled to receive that Notice, whether before or after the time stated therein, will be equivalent to the giving of that Notice.

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7.6 Governing Law

This PA and all Disputes arising under this PA shall be governed by and construed in accordance with the laws of the State of Alaska, without regard to the conflicts of law principles thereof, and the federal laws applicable therein.

7.7 Dispute Resolution

- (a) All Disputes shall be referred to the Senior Executives of the Parties, upon which:
 - (i) the Senior Executives representing the Parties shall meet within five (5) days of submission of the Dispute at a mutually acceptable time and place to exchange relevant information in an attempt to resolve the Dispute;
 - (ii) if a Senior Executive intends to be accompanied at the meeting by any other Person, the other Party's Senior Executive shall be notified of such intention at least three (3) Business Days in advance of the meeting and may also be accompanied to the meeting by another Person, provided that the maximum number of Persons from each Party shall be limited to three (3) including the Senior Executive;
 - (iii) all Persons (other than the Senior Executive) shall attend the meetings only as advisors to the Senior Executive they accompany; and
 - (iv) the Parties shall cause their respective Senior Executives to work together diligently and in good faith with the objective to resolve any Disputes consistent with the principles of this PA as soon as reasonably practicable.
- (b) Any and all Disputes not resolved by the Senior Executives shall be resolved in accordance with the following:
 - (i) Jurisdiction. Each of the Parties irrevocably agrees that any legal action, suit or proceeding arising out of or relating to this PA brought by any Party or its successors or assigns shall be brought and determined in the state courts of the State of Alaska, except that claims which are in the exclusive jurisdiction of the federal courts may be brought and determined in federal court in Alaska, and each of the Parties hereby irrevocably submits to the exclusive jurisdiction of the aforesaid courts for itself and with respect to its property, generally and unconditionally, with regard to any such proceeding arising out of or relating to this PA or the transactions contemplated by this PA. Each of the Parties agrees not to commence any proceeding relating to this PA except in the courts described above in Alaska, other than proceedings in any court of competent jurisdiction to enforce any judgment, decree or award rendered by any such court in Alaska as described herein. Each of the Parties further agrees that Notice as provided in Section 7.5 shall constitute sufficient service of process and the Parties further waive any argument that such service is insufficient. Each of the Parties hereby irrevocably and unconditionally waives, and agrees not to assert, by way of motion or as a defense, counterclaim or otherwise, in any proceeding arising out of or relating to this PA or the transactions contemplated by this PA, (i) any claim that it is not personally subject to the jurisdiction of the courts in Alaska as described

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herein for any reason, (ii) that it or its property is exempt or immune from jurisdiction of any such court or from any legal process commenced in such courts (whether through service of notice, attachment prior to judgment, attachment in aid of execution of judgment, execution of judgment or otherwise) and (iii) that (A) the proceeding in any such court is brought in an inconvenient forum, (B) the venue of such proceeding is improper or (C) this PA, or the subject matter hereof, may not be enforced in or by such courts.

- (ii) WAIVER OF JURY TRIAL. EACH PARTY HEREBY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN ANY LEGAL PROCEEDING DIRECTLY OR INDIRECTLY ARISING OUT OF OR RELATING TO THIS PA OR THE TRANSACTIONS CONTEMPLATED HEREBY (WHETHER BASED ON CONTRACT, TORT OR ANY OTHER THEORY). EACH PARTY (I) CERTIFIES THAT NO REPRESENTATIVE, AGENT OR ATTORNEY OF ANY OTHER PARTY HAS REPRESENTED, EXPRESSLY OR OTHERWISE, THAT SUCH OTHER PARTY WOULD NOT, IN THE EVENT OF LITIGATION, SEEK TO ENFORCE THE FOREGOING WAIVER AND (II) ACKNOWLEDGES THAT IT AND THE OTHER PARTIES HERETO HAVE BEEN INDUCED TO ENTER INTO THIS PA BY, AMONG OTHER THINGS, THE MUTUAL WAIVERS AND CERTIFICATIONS IN THIS SECTION 7.7(b).
- (iii) Confidentiality. To the extent permitted by law, all negotiations, mediation and court determinations relating to a Dispute (including a settlement resulting from negotiation or mediation, a court order, documents exchanged or produced during a mediation or legal proceeding, and memorials, briefs or other documents prepared for any Dispute resolution) are confidential and may not be disclosed by the Parties, their Affiliates, and their respective employees, officers, directors, counsel, consultants, and expert witnesses, except (in accordance with Section 7.1) to the extent necessary to enforce this Section 7.7 or any court order, to enforce other rights of a Party, or as required by law or applicable securities exchange or securities commission; provided, however, that unintentional breach of this confidentiality provision shall not void any settlement or award.
- (iv) Costs of Dispute. Each Party shall bear its own expenses and costs incurred in connection with the proceedings, including attorneys' fees with respect to any Dispute.

7.8 Assignment

- (a) Shipper may only assign its rights and obligations under this PA and the FTSA with Transporter's consent (not to be unreasonably withheld), provided the assignee assumes in writing such rights and obligations on terms and conditions satisfactory to Transporter, including meeting and maintaining the Creditworthiness Requirements.
- (b) Where a proposed transferee of Shipper's interest pursuant to Section 7.8(a):
 - (i) is the State (or an Affiliate or agency thereof) and AS 09.50.250 – AS 09.50.280 has been repealed or amended in a manner such that the proposed transferee has or

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may have a right to claim sovereign immunity for any matters arising out of this PA or the FTSA, or

- (ii) is a government entity (or an Affiliate or agency thereof) other than the State or an Affiliate or agency thereof that now or hereafter has a right to claim sovereign immunity for itself or any of its assets,

then it shall be a condition precedent to the effectiveness of an assignment pursuant to this Section 7.8 (and the equivalent provision of the FTSA) that:

- (iii) the transferee acknowledges that its rights and obligations under this PA and the FTSA are of a commercial and not a governmental nature, and
 - (iv) the transferee waives any current or future immunity to the fullest extent permitted by Governmental Requirements of any applicable jurisdiction for any matters arising out of this PA and the FTSA. This waiver includes immunity from (A) any expert determination, mediation, or arbitration proceeding commenced pursuant to the applicable agreement; (B) any judicial, administrative or other proceedings to aid the expert determination, mediation, or arbitration commenced pursuant to the applicable agreement; and (C) any effort to confirm, enforce, or execute any decision, settlement, award, judgment, service of process, execution order or attachment (including pre-judgment attachment) that results from an expert determination, mediation, arbitration or any judicial or administrative proceedings commenced pursuant to such agreement.
- (c) Transporter may assign its rights and obligations under this PA or the FTSA to an Affiliate either (i) if the Shipper is the State (or an Affiliate of the State), with the prior written consent of Shipper (not to be unreasonably withheld), provided the assignee assumes in writing such rights and obligations on terms and conditions satisfactory to Shipper, or (ii) in all other instances, without the prior written consent of Shipper, provided that timely Notice of its intended assignment is provided to Shipper.
 - (d) Transporter shall not assign its rights or obligations under this PA or FTSA to a non-Affiliate without the prior written consent of Shipper (not to be unreasonably withheld), provided the assignee assumes in writing such rights and obligations on terms and conditions satisfactory to Shipper.

7.9 General

- (a) **Binding Effect:** This PA binds, and inures to the benefit of, the Parties and their respective successors (including any successor by reason of amalgamation of any Party) and permitted assigns.
- (b) **Governmental Requirements:** This PA, and the rights and obligations of the Parties under this PA are subject to all valid and applicable Governmental Requirements, except choice of law or conflict-of-laws rules or principles under Section 7.6.
- (c) **Severability:** If, in any jurisdiction, any provision of this PA or its application to any Party or circumstance is restricted, prohibited or unenforceable, such provision shall, as to such jurisdiction, be ineffective only to the extent of such restriction, prohibition or

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unenforceability without invalidating the remaining provisions of this PA and without affecting the validity or enforceability of such provision in any other jurisdiction or without affecting its application to other Parties or circumstances.

- (d) **Relationship of the Parties:** Neither this PA nor any other documentation or communication between the Parties shall constitute or create a joint venture, partnership, legal entity, or other similar business combination or arrangement between the Parties. Each Party shall act only on an individual and several basis. No Party shall have the right to act as an agent for or a servant or employee of the other Party, to make commitments or assume obligations for and on behalf of the other Party, or to bind the other Party for any purpose whatsoever.
- (e) **Waiver:** No waiver by a Party of any breach by any other Party in the performance of any provision, condition, or requirement of this PA is deemed to be a waiver of, or in any manner a release of such Party from, performance of any other provision, condition, or requirement. No waiver is deemed to be a waiver of, or in any manner a release of such other Party from future performance of the same provision, condition, or requirement; nor shall any delay or omission of a Party to exercise any right hereunder in any manner impair the exercise of any such right or any like right accruing to it thereafter. Any waiver of any provision, condition, or requirement of this PA is valid only if it is in writing and signed by the Party against whom it is sought to be enforced.
- (f) **Waiver of Sovereign Immunity:** The provisions of AS 09.50.250 – AS 09.50.280 permit Transporter to bring an action against Shipper arising under this PA. The Parties agree any change in Alaska law that eliminates or materially impairs Transporter's rights to bring an action under this PA shall be deemed to be a Discriminatory Change in Law. Shipper acknowledges that its rights and obligations hereunder are of a commercial and not a governmental nature.
- (g) **Amendment:** No amendment, supplement, modification or waiver or termination of this PA and, unless otherwise specified, no consent or approval by either Party, shall be binding unless executed in writing by the Party to be bound thereby.
- (h) **Further Assurances:** Each Party agrees to use reasonable efforts to take, or to cause to be taken, all actions, and to do, or to cause to be done, all things reasonably necessary or appropriate to consummate the actions this PA contemplates.
- (i) **Entire Agreement:** This PA and any other documents or agreements between the Parties delivered in connection with this PA constitute the entire agreement of the Parties relating to their relationship under this PA. All prior negotiations and all provisions and concepts contained in all prior agreements (including the MOU and the Alaska LNG Midstream Services Term Sheet attached as Exhibit C to the MOU) between the Parties on matters contained in this PA are expressly superseded by this PA. The Parties expressly waive any reliance on representations or course of dealings made prior to the execution of this PA regarding the subject of this PA.
- (j) **Third Party Beneficiaries:** No provision of this PA confers, or is to be construed, deemed or interpreted as conferring, on any Person other than the Parties, any rights or remedies hereunder.

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- (k) **Execution and Delivery:** This PA may be executed in one or more counterparts, all of which will be considered one and the same agreement and will become effective when two or more counterparts have been signed by each of the Parties named on the original signature pages hereof and delivered to the other Party, it being understood that the Parties need not sign the same counterpart.

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Execution page follows

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IN WITNESS OF WHICH the Parties have duly executed and delivered this PA.

**TRANSCANADA ALASKA
MIDSTREAM LP, by its general partner,
TRANSCANADA ALASKA GP INC.**

THE STATE OF ALASKA

By:

Name:
Title:

By:

Name:
Title:

By:

Name:
Title:

SCHEDULE A
Definitions and Interpretation

Section 1 – Definitions

In the PA, unless the context otherwise requires:

“**Acid Gas**” means CO₂, H₂S and other impurities contained in natural gas.

“**Additional Gas**” has the meaning specified in Schedule B.

“**Affiliate**” means in relation to a Party any company, corporation, partnership or other legal entity (in this definition, each such entity and each Party are sometimes referred to as a “**Company**”) which is:

- (a) directly or indirectly, owned or controlled by such Party;
- (b) directly or indirectly owns or controls such Party; or
- (c) directly or indirectly, owned or controlled by a Company that also, directly or indirectly, controls such Party.

For the purpose of this definition:

- (i) a Company is directly owned or controlled by another Company that owns or controls shares or other interests carrying in the aggregate more than 50 percent of the voting rights exercisable at a general, shareholders, or members meeting of the first-mentioned Company, or the right to appoint or dismiss a majority of the directors thereof, or the power to direct or cause the direction of the management or policies through the ownership of securities, by contract or otherwise. A Company is indirectly owned or controlled by a Company or Companies (the “parent Company or Companies”) if a series of Companies can be specified, beginning with the parent Company or Companies and ending with the particular Company, so related that each Company of the series, except the parent Company or Companies, is directly controlled by one or more of the Companies in the series.
- (ii) in relation to Shipper, those State entities that otherwise meet the definition of “Affiliate” set forth above, when acting only in the State’s proprietary capacity (and not in a governmental capacity), including State corporations or authorities established by statute as instrumentalities of the State.

“**AGDC**” means the Alaska Gasline Development Corporation.

“**AGIA**” means the Alaska Gasline Inducement Act, AS 43.90, as well as the regulations promulgated thereunder.

“**AGIA License**” means the Alaska Gasline Inducement Act License issued December 5, 2008, by the State of Alaska to the AGIA Licensee, under the authority of AGIA, as amended by project plan amendments approved on January 29, 2010, May 2, 2012, June 11, 2013 and December 12, 2013.

“**AGIA Licensee**” means collectively, TransCanada Alaska Company, LLC and Foothills Pipe Lines Ltd.

“AGIA Project Plan Amendment 1B” means the project plan amendment under the AGIA License approved by the Alaska Commissioner of Natural Resources and the Alaska Commission of Revenue pursuant to AS 43.90.210 on December 12, 2013.

“Agreed Interest Rate” means interest compounded on a monthly basis, at the rate per annum equal to (a) the one (1) month term LIBOR rate applicable on the first Business Day prior to the due date of payment and thereafter on the first Business Day of each succeeding calendar month, plus (b) 10%. If the aforesaid rate is contrary to any applicable usury law, the rate of interest to be charged shall be the maximum rate permitted by such applicable law.

“AKLNG Development Costs” means all costs and expenses incurred under the CSA or any Project Agreement to which Transporter or any of its Affiliates is a Party, which shall include:

- (a) any contract cancellation penalties and continued funding obligations under such agreements;
- (b) all costs payable pursuant to [REDACTED] of the Pre-FEED JVA or equivalent articles under the CSA or other Project Agreements.

AKLNG Development Costs shall not include any costs or expenses for which Transporter or its Affiliates have received payment or reimbursement under the CSA or other Project Agreements.

“Alaska North Slope” means that part of the State that lies north of 68 degrees north latitude.

“Alaska LNG Project” means collectively, (i) the Midstream Facilities, and (ii) the LNG Plant.

“Alaska LNG Parties” means, collectively, as of the Effective Date, Transporter, the Producer Parties and AGDC and their respective Affiliates that have an equity or participation interest in the Alaska LNG Project.

“Annual Decommissioning Allowance” has the meaning specified in paragraph 5 of Part D of Schedule C.

“Audit Protocol” means the protocol for the review and audit of information by Shipper as set forth in Schedule E.

“Business Day” means a day, other than a Saturday, Sunday or holiday, on which federally chartered banks are open for commercial banking business (including dealings in foreign exchange and foreign currency deposits) in both Calgary, Alberta, Canada and Anchorage, Alaska.

“Buy-Back Notice Date” has the meaning specified in Schedule B.

“Carrying Cost Calculation” means the calculation of interest on a particular cost or expenditure forming part of the Development Costs, calculated at a rate of 7.1% per annum and compounded monthly and accruing daily. Such interest shall accrue, in respect of such cost or expenditure, from the later of (i) the FERC Pre-Filing Date, and (ii) the 15th day of the calendar month of the month such cost or expenditure was incurred, until the date of payment.

“Claims” means, in relation to any Person, any and all claims, actions, causes of action, accounts, liens, demands, lawsuits, suits, judgments, awards, adjudications, writs, orders, audits, proceedings, arbitrations, mediations, hearings, investigations or actions by any Governmental Authority, brought against or suffered, sustained or incurred by such Person, in each case whether fixed or contingent or foreseen or unforeseen, and whether based on contract, tort, statute or other legal or equitable theory of recovery.

“Confidentiality Agreement” means the Alaska LNG Project Confidentiality Agreement entered into by the State, Transporter, AGDC and TADI dated on or about the Effective Date, as such agreement may be amended from time to time.

“Consequential Loss” means, as to any Person, any damage, cost, expense, liability, or loss (including pass-through claims for indemnification or contribution owed to another Person under a contract, governmental requirement, or other obligation) of that Person that is caused (directly or indirectly) by any of the following arising out of, relating to, or connected with the PA or work carried out (or failed to be carried out) in relation to it: loss or deferment of income or profits; loss of use of any asset; loss of business or reputation; loss of business opportunity; loss of labor or management productivity; increases in wage, salary, or other cost of labor cost; or other indirect damages or losses, costs, expenses, or liabilities, whether or not similar to the foregoing; in addition, Consequential Loss includes any exemplary (whether statutory or common law), punitive, special, or treble or other multiple damages. Without limiting the generality of the foregoing, Consequential Losses include any:

- (a) losses arising as a result of hedges, swaps, derivatives, forwards, futures, options; and
- (b) loss of any contract of Shipper.

Notwithstanding any other provision of the foregoing definition, Consequential Losses shall not include:

- (i) any payment obligations to Transporter as set forth in the PA or FTSA (or any accelerations thereof as damages for a breach of contract), including (1) payment of the Termination Amount, or (2) payment of the Total Obligation under the PA or FTSA, as applicable; or
- (ii) to the extent direct contract damages that would otherwise meet the definition of Consequential Loss have been awarded to a non-Affiliate third party and are subject to allocation between or among the Parties to the Dispute.

“Conveyance Assets” has the meaning specified in the Transporter Conveyance Mechanics.

“Coordination Committee” has the meaning specified in Section 5.2(a).

“Credit Support Provider” has the meaning specified in Schedule D.

“Creditworthiness Requirements” means those requirements specified in Schedule D.

“Creditworthy” means, in respect of any Person, a Person that satisfies the requirements set forth in paragraph 1 or paragraph 2 of Schedule D at the relevant time.

“CSA” means the Concept Selection Agreement for ANS Gas Development dated March 29, 2012 between TADI and Affiliates of the Producer Parties, as amended from time to time.

“Default Event” means any one of the events of default specified in Sections 6.1 or 6.3.

“Delivery Point” means the point of custody transfer for the delivery of natural gas on a Midstream Facility, which shall be on the outlet side of the measurement station or at such other point as may be agreed upon between Transporter and Shipper.

“Development Costs” means all Prudent Costs incurred by Transporter and its Affiliates after December 31, 2013 in the development, design, financing, construction, acquisition and commissioning of the Midstream Facilities, which costs shall be comprised of only (i) the AKLNG Development Costs, and (ii) the Transporter Development Costs, deducting from the sum of (i) and (ii) the following amounts:

- (a) all AGIA payments received and retained by the AGIA Licensee relating to Transporter’s or its Affiliates’ share of development costs for activities authorized under the AGIA Project Plan Amendment 1B and carried out after December 31, 2013; and
- (b) all proceeds received by Transporter or its Affiliates from the State, any State Affiliate or State entity for use of the work or data created with the AKLNG Development Costs or the Transporter Development Costs.

“Development Cost Amount” has the meaning specified in Section 4.3(a).

“Discriminatory Change in Law” has the meaning specified in Section 7.4.

“Dispute” means a dispute, matter, controversy or claim between or among the Parties or their Affiliates arising out of or relating to the PA or FTSA (as applicable), including the validity, interpretation, construction or enforcement of this PA, or a Party’s (or a Party’s Affiliate’s) performance, privileges, rights or obligations under or with respect to the PA or FTSA (as applicable), including the Audit Protocol.

“Dispute Resolution Procedure” means, (i) for purposes of the PA, the procedure set forth in Section 7.7; and (ii) for purposes of the FTSA, the applicable dispute resolution procedure set forth in the FTSA, which is intended to be materially consistent with that described in Schedule B.

“Dollars” and the sign “\$” means US dollars.

“Downstream Activities” means all operations and activities undertaken with respect to the LNG Plant as part of the Alaska LNG Project.

“Effective Date” has the meaning specified in the preamble to the PA.

“Enabling Legislation” means Chapter 14 SLA 14 (also known as Senate Bill 138).

“End of ICT Purchase Price” means an amount equal to the greater of (a) \$1, and (b) the net book value determined as the difference between the GPIS Balance, less the Accumulated Depreciation amount as of the end of the ICT, plus (i) the book value of any physical materials and supplies, and (ii) any prepayments of amounts by Shipper that have not amortized prior to the end of the ICT, subject to adjustments reflecting reconciliations consistent with paragraph 6 of Part C of Schedule C.

“Entity” means any foreign or domestic general partnership, limited partnership, limited liability company, corporation, joint enterprise or venture, joint stock company, business or statutory trust, employee benefit plan, cooperative, association, or other legal entity.

“Expansion” has the meaning specified in Schedule B.

“Expansion Shipper” has the meaning specified in Schedule B.

“Expiry Date” has the meaning specified in Section 4.1.

“FEED” means a front-end engineering and basic engineering design study, which the Parties anticipate to include the following (with the detailed work plan and deliverables of FEED being developed during Pre-FEED):

- (a) Sufficiently detailed basic engineering packages for the components of the Alaska LNG Project and a contracting strategy to enable contractor bidding for the Engineering, Procurement and Construction (“EPC”) contracts;
- (b) A resourcing, commissioning and start-up plan;
- (c) The finalization of those Key Project Agreements (to be entered into after the FEED Agreement) required to implement the Alaska LNG Project;
- (d) A technical and commercial definition of the Alaska LNG Project;
- (e) A detailed update of the Alaska LNG Project economics, financing and commercial assumptions, including an updated estimate of capital costs sufficient for a final investment decision;
- (f) A final assessment of environmental, social and health impacts of the Alaska LNG Project;
- (g) Long-lead procurement activities;
- (h) Other activities necessary to enable a final investment decision to be taken by the Alaska LNG Parties such as but not limited to financing, permitting and registration; and
- (i) The bidding and internal selection of EPC contractors, as applicable.

“FEED Agreement” means the agreement under which FEED would be undertaken for the Alaska LNG Project.

“FEED Decision” [REDACTED] as defined in the Pre-FEED JVA.

“FERC” means the Federal Energy Regulatory Commission and any successor thereof.

“FERC Pre-Filing Date” means the date of FERC approval of Alaska LNG Project’s request to initiate the pre-filing process.

“FID” means the final investment decision by some or all of the Alaska LNG Parties to proceed to construct the Alaska LNG Project.

“Financial Security” has the meaning specified in Schedule D.

“FTSA”, means one or more transportation services agreements entered into by Transporter and Shipper (or their permitted assigns) for the Pipelines and the GTP, containing terms and conditions substantially consistent with the FTSA Terms.

“FTSA Decision Date” means December 31, 2015 or such later date as the Parties may agree.

“FTSA Legislation” means legislation to be enacted by the Alaska Legislature that has become effective as provided under AS 01.10.070, that authorizes Shipper to enter into the FTSA and to the extent applicable to fund, subject to appropriation, the State’s direct and contingent payment obligations for the Termination Amount under the FTSA.

“FTSA Terms” has the meaning specified in Section 2.2(a).

“Gas Pipeline” means the Alaska LNG Project component consisting of a main natural gas pipeline from the outlet flange of the GTP on the Alaska North Slope to the inlet flange of the LNG Plant, which may have five (5) or more off-take points along the pipeline for deliveries of gas within the State. The term “Gas Pipeline” refers to the main gas pipeline and does not include any gas pipelines downstream of any off-take point between the GTP and the LNG Plant.

“Gas Treatment Plant” or **“GTP”** means the Alaska LNG Project component consisting of facilities and related activities to receive natural gas from the PBU Gas Transmission Line, the PTU Gas Transmission Line, and/or other facilities, treat the natural gas to pipeline quality specifications, dispose of or deliver by-products, deliver liquid products for further transportation, and deliver treated natural gas for transportation through the Gas Pipeline.

“Governmental Authority” means:

- (a) any domestic or foreign federal, provincial, state, territorial, county, regional district, borough, city, municipal or other government or any agency, board, bureau, commission, court, department, or other instrumentality of any such government acting in a governmental capacity; or
- (b) any Person having the authority under any applicable governmental requirement to assess and collect taxes for its own account;

in each case having jurisdiction or authority in regard to the applicable Person or thing.

“Governmental Requirement” means any applicable obligation, limitation or requirement that applies to the Midstream Facilities or the Parties:

- (a) under any law, including the common law and any statute, code, ordinance, order, rule, regulation, judgment, decree, injunction, writ, edict, award, authorization or other requirement of any Governmental Authority;
- (b) included in any issued Regulatory Approval; or
- (c) resulting from binding arbitration or mediation with a Governmental Authority.

“Gross Negligence” means any act or failure to act (whether sole, joint or concurrent) by Senior Supervisory Personnel of Transporter which was a reckless disregard of or wanton indifference to, harmful consequences such Person knew, or should have known, that such act or failure to act would have on the safety or property of another Person.

“HOA” has the meaning specified in Recital A.

“HOA Parties” has the meaning specified in Recital A.

“ICT” has the meaning specified in Schedule B.

“ISD” means the commercial in-service date of the Alaska LNG Project.

“Initial System” means the Midstream Facilities as initially constructed and placed in service as of ISD.

“Insolvency Event” means, in relation to any Person, the occurrence of one or more of the following:

- (a) an order is made or an effective resolution passed for the winding-up, liquidation or dissolution of the Person;
- (b) the Person institutes proceedings for its winding up, liquidation or dissolution, or takes action to become a voluntary bankrupt, or consents to the filing of a bankruptcy proceeding against it, or files a proposal, a notice of intention to make a proposal, a petition or answer or consent seeking reorganization (including under any Insolvency Law), readjustment, arrangement, composition or similar relief under any Insolvency Law or consents to the filing of any such petition, or consents to the appointment of a receiver, liquidator, trustee or assignee in bankruptcy or insolvency of all or a substantial part of the property of the Party or makes an assignment for the benefit of creditors, or admits in writing its inability to pay its debts generally as they come due, or commits any other act of bankruptcy, or suspends or threatens to suspend transaction of its usual business, or any action is taken by the Person in furtherance of any of the aforesaid;
- (c) a court having jurisdiction enters a decree or order adjudging the Person a bankrupt or insolvent, or approving as properly filed a petition seeking reorganization, readjustment, arrangement, composition or similar relief under any Insolvency Law, or a decree or order of a court having jurisdiction for the appointment of a receiver, liquidator, trustee or assignee in bankruptcy or insolvency of all or a substantial part of the undertaking or property of the Person, or for the winding up, dissolution or liquidation of its affairs, is entered and the decree, order or petition is not contested and the effect of it stayed, or any material part of the property of the Person is sequestered or attached and is not returned to the possession of the Person or released from such attachment within twenty (20) days thereafter;
- (d) any proceedings, voluntary or involuntary, are commenced, or an order or petition is issued, respecting the Person pursuant to any Insolvency Law;
- (e) the Person causes or institutes any proceeding for its dissolution or termination; or
- (f) the Person is generally not paying its debts as they become due or makes a general assignment for the benefit of creditors.

“Insolvency Law” means any Governmental Requirement respecting bankruptcy, insolvency, fraudulent preferences or other matters affecting the rights of creditors generally.

“Integrated Matters” means, collectively, those Alaska LNG Project activities related to both (i) the Downstream Activities, and (ii) the Midstream Activities, as contemplated by [REDACTED] of the Pre-FEED JVA.

“Key Project Agreements” means, collectively, the HOA, the Pre-FEED JVA, the FEED Agreement, the Project Equity Participation Agreement and those other material Project Agreements relating to the development and operation of the Midstream Facilities or the Alaska LNG Project as a whole.

“Liabilities” or **“Liability”** means any and all liabilities and obligations, whether under common law, in equity, under any Governmental Requirement or otherwise, whether tortious, contractual, vicarious, statutory or otherwise, whether absolute or contingent and whether based on fault, strict liability or otherwise.

“LIBOR” means, for any calendar month (one of the twelve (12) calendar months of the calendar year commencing on the first day of each calendar month, in accordance with the Gregorian Calendar, and the term “Monthly” shall be construed accordingly, the percentage rate per annum, compounded on a

monthly basis, equal to the average of the annual yield rates applicable to one-month dollar deposits which rate is shown on the display referred to as the "LIBOR Page" (or any display substituted therefor) of Reuter Monitor Money Rates Service (or its successor) as at approximately 10:00 a.m. (New York time) on the first Business Day of that month.

"**Linefill Gas**" has the meaning specified in Schedule B.

"**Losses**" means, in relation to a matter, any and all losses, damages, costs, disbursements, out-of-pocket expenses, charges, indebtedness, obligations, assessments, fines, penalties, fees and expenses of every kind, nature or description incurred or sustained by a Person, including court costs, costs incurred or sustained in connection with any Claims (including Professional Fees and reasonable costs of investigating and defending Claims) arising from such matter, regardless of whether such Claims are sustained, together with any interest which may be imposed in connection therewith.

"**LNG**" means any hydrocarbon or mixture of hydrocarbons consisting predominantly of methane in a liquid state at or below its boiling point at a pressure of approximately one (1) atmosphere.

"**LNG Plant**" means the Alaska LNG Project component consisting of an LNG plant facility, including the structures, equipment, underlying land rights and all other associated systems, for pre-processing and liquefaction of natural gas, and storage and off-loading of liquefied natural gas, including terminal facilities and auxiliary marine vessels.

"**Maintenance Capital Additions**" means, collectively, facility additions required to maintain the reliable capacity of the Midstream Facilities or to extend the useful life of the facilities, for which costs have not been expensed as Annual Fixed O&M Expenses as described in Schedule C, part D, paragraph 6.

"**Midstream Activities**" means all operations and activities undertaken with respect to the Midstream Facilities as part of the Alaska LNG Project.

"**Midstream Facilities**" means, collectively: (i) the PBU Gas Transmission Line, (ii) the PTU Gas Transmission Line, (iii) the Gas Pipeline, and (iv) the Gas Treatment Plant, and "**Midstream Facility**" means any one of them.

"**Moody's**" means Moody's Investors Service, Inc. or its successor.

"**MOU**" has the meaning specified in Recital C.

"**NGA**" means the Natural Gas Act, 15 U.S.C. § 717b, *et seq.*

"**Negotiated Rate**" means the negotiated rate for the provision of the Services, calculated in accordance with the Negotiated Rate Principles.

"**Negotiated Rate Principles**" means the Negotiated Rate principles set forth in Schedule C.

"**Nominee**" has the meaning specified in Section 5.2(b).

"**Notice**" has the meaning specified in Section 7.5(a).

"**Other Shipper**" has the meaning specified in Schedule B.

"**PA**" means the agreement to which this Schedule A forms a part, together with all Schedules attached to such agreement, and any extension, renewal or amendment thereof agreed to in writing by the Parties.

“Partnership Asset Conveyance” means an election by Shipper pursuant to the Transporter Conveyance Mechanics.

“Partnership Interest Conveyance” means an election by Shipper pursuant to the Transporter Conveyance Mechanics.

“Party” means Shipper or Transporter individually, and **“Parties”** means Shipper and Transporter collectively.

“PBU Gas Transmission Line” means the Alaska LNG Project component consisting of a natural gas transmission line from the outlet flange of the Prudhoe Bay Unit Central Gas Facility to the inlet flange of the GTP, including the structures, equipment, underlying land rights and all other associated systems.

“Pre-FEED” means pre-front-end engineering and design work and activities on the approved concept in preparation for FEED for the Alaska LNG Project, including technical and execution studies and optimization and FEED/EPC invitation to tender development including sufficient design detail and environmental field work to support FERC applications and filings.

“Pre-FEED JVA” means the Alaska LNG Project Pre-FEED Venture Agreement to be executed, after Enabling Legislation becomes effective, by the Producer Parties, Transporter and AGDC on terms acceptable to the parties thereto, as may be amended from time to time.

“Person” means any natural person, Entity, estate, labour union, or Governmental Authority.

“Pipelines” means, collectively, the PTU Gas Transmission Line, the PBU Gas Transmission Line and the Gas Pipeline, and **“Pipeline”** means any one of them.

“Point Thomson Unit” means the oil and gas leases and described land located on the North Slope of Alaska as may exist from time to time from which oil, gas and associated substances are developed and produced on a unitized basis under the terms of the Unit Agreement for the Development and Operation of the Point Thomson Unit with the State of Alaska, dated March 1, 1977 and the Unit Operating Agreement Point Thomson Unit Area by and between the Working Interest Owners of the Point Thomson Unit, dated March 1, 1977, each as amended from time to time.

“Pre-Construction Regulatory Approvals” means, collectively, those Regulatory Approvals that are, in the opinion of Transporter, material and customarily required by prudent pipeline operators prior to the commencement of on-site construction or pre-construction activities.

“Prior Capital Contribution” means the Transporter’s Affiliates share of costs incurred on the Alaska portion of the AGIA Project from December 5, 2008 to the effective date of the Pre-FEED JVA that have not otherwise been included as Development Costs, less a credit equal to the AGIA reimbursement received and retained by the Transporter or its Affiliates that were associated with such costs. The maximum amount of Prior Capital Contribution shall be determined as agreed by the Parties prior to the FTSA Decision Date and shall not exceed \$70 million.

“Producer Parties” means ExxonMobil LNG LLC, BP Alaska LNG LLC and ConocoPhillips Alaska LNG Company, and their respective upstream Affiliates operating in Alaska, and such parties’ successors in interest in accordance with the agreements governing the Alaska LNG Project.

“Professional Fees” means reasonable: (i) fees and disbursements of legal counsel on a solicitor and his own client basis; and (ii) fees and disbursements of any other professional advisors and consultants, including expert witnesses, and such other reasonable out-of-pocket expenses as are incurred in connection with such professional advisors and consultants.

“Project Agreements” means, collectively, those final agreements among any or all of the Alaska LNG Parties, the State and Shipper to (i) give effect to the HOA, and (ii) develop, construct, own or operate the Alaska LNG Project, including the HOA, the Pre-FEED JVA, the FEED Agreement and the Project Equity Participation Agreement.

“Project Equity Participation Agreement” means the agreement or agreements including some or all of the Producer Parties, Transporter and AGDC under which the ownership structure of the Alaska LNG Project and the holding of participating equity interests (including the Shipper Percentage) are established.

“Project Information” has the meaning specified in Section 5.1(a).

“Prudent Costs” means those incurred costs that could reasonably be expected to be incurred by a qualified, experienced, responsible and financially sound developer of facilities in the nature of the Midstream Facilities, acting reasonably, prudently, fairly and in good faith. Prudent Costs shall include those incurred costs deemed to be prudently incurred pursuant to Section 5.3(c) or the Audit Protocol.

“Prudhoe Bay Unit” means the oil and gas leases and described land located on the North Slope of Alaska as may exist from time to time from which oil, gas and associated substances are developed and produced under the terms of the Unit Agreement Prudhoe Bay Unit with the State of Alaska, dated April 1, 1977 and the Unit Operating Agreement Prudhoe Bay Unit by and between the Working Interest Owners of the Prudhoe Bay Unit, dated April 1, 1977, each as amended from time to time.

“PTU Gas Transmission Line” means the Alaska LNG Project components consisting of a natural gas transmission line from the outlet flange of the Point Thomson Unit production facility to the inlet flange of the GTP, including the structures, equipment, underlying land rights and all other associated systems.

“Rate Base” has the meaning as specified in Schedule C.

“Receipt Point” means the point of custody transfer for the receipt of natural gas into a Midstream Facility, which shall be on the inlet side of the measurement station or at such other point as may be agreed between Transporter and Shipper.

“Regulatory Approvals” means collectively, such applications, accreditations, authorizations, approvals, declarations, qualifications, notifications, consents, permits, franchises, certificates, licenses, waivers, implementing orders, or exemptions, or registrations or filings, and any necessary amendments or supplements thereto, of any Governmental Authority, that Transporter or its Affiliate, in its sole discretion, determines are necessary for, and are on terms satisfactory to, Transporter or its Affiliate for the construction, ownership and operation of the Midstream Facilities and to provide the Services.

“Related Parties” means Affiliates and any respective representatives, successors, assigns, officers, directors, employees, shareholders, members, agents, contractors, consultants and advisors of a Person or Persons.

“Remaining Useful Life of the Midstream Facilities” means, at any time, the estimated length of time remaining before the Midstream Facilities will need to be decommissioned, taking into account the condition, operating environment, service level, capacity utilization, technical obsolescence and functional obsolescence of such facilities, as well as the remaining useful life of the Midstream Facilities determined pursuant to the Key Project Agreements, as such time is (i) determined by an independent qualified expert appointed as agreed by the Parties, or (ii) otherwise agreed to by the Parties.

“**Renewal Date**” has the meaning specified in Schedule B.

“**Required Accounting Practice**” means the usual and customary accounting practices of Transporter or its Affiliates consistently applied in businesses similar to that conducted by Transporter.

“**Revised Transporter Estimate**” has the meaning specified in Section 5.3(b)(ii).

“**S&P**” means Standard & Poor’s Financial Services LLC or its successor.

“**Senior Executive**” means any individual who has the authority to negotiate and bind the Party to a settlement of the Dispute for that Party. For purposes of the State, the Commissioner of the Department of Natural Resources is the Senior Executive.

“**Senior Supervisory Personnel**” means any individual who functions for the Party or one of its Affiliates at a management level equivalent or superior to any individual functioning as such Party’s senior manager who has direct responsibility for, and directs all operations of such Party in relation to the Midstream Facilities, but excluding all individuals functioning at a level below this position.

“**Services**” has the meaning specified in Schedule B.

“**Shipper**” has the meaning specified in the preamble to the PA.

“**Shipper Condition**” has the meaning specified in Section 3.1.

“**Shipper Decision Date**” has the meaning specified in Section 5.3(a)(ii).

“**Shipper Percentage**” has the meaning specified in Recital B.

“**Shipper WP&B Notice**” has the meaning specified in Section 5.3(a)(ii).

“**State**” means the State of Alaska. As of the Effective Date, the Shipper is the State.

“**State Gas Share**” means, collectively, the State’s share of royalty in kind gas and gas production tax as gas provided by the Producer Parties and received by the State from the Producer Parties’ natural gas resources on the North Slope of Alaska, should the State elect to receive its royalty in kind and production tax as gas.

“**State Shipper**” means Shipper, where Shipper meets the following criteria:

- (a) is the State;
- (b) holds (pursuant to this PA or the FTSA) at least 50% of the Transporter Capacity of the Gas Pipeline and the GTP, and
- (c) it or its Affiliate is not otherwise in default under this PA, the FTSA or any other agreement in relation to the Alaska LNG Project between Transporter or its Affiliates and Shipper or its Affiliates.

“**TADI**” means TransCanada Alaska Development Inc., a Delaware corporation.

“**Tax**” means all income, profits, capital gains, franchise, use, ad valorem, property, excise, payroll, stamp, documentary, real property transfer or gain, gross receipts, goods and services, harmonized sales, pipeline transportation, user, value added, sales, registration, transfer, withholding, or other tax, fee, assessment, or charge any Governmental Authority imposes, including any interest, penalty, or additional amount it also may impose on the tax, fee, assessment, or charge.

“**TC MOU Parties**” has the meaning specified in Recital C.

“**Term**” has the meaning specified in Schedule B.

“**Termination Amount**” has the meaning specified in Section 4.3(b) for purposes of the PA, and for purposes of the FTSA Terms and the FTSA, as specified in provisions comparable to Section 4.3(b).

“**Termination Amount Objection**” has the meaning specified in Section 4.3(c)(ii).

“**Termination Amount Notice**” has the meaning specified in Section 4.3(c)(i).

“**Termination Date**” means the earlier to occur of (i) the Expiry Date, and (ii) the date on which the PA terminates under Section 4.2.

“**Total Obligation**” means: (i) for the period prior to ISD, an amount equal to the Shipper Percentage of the total development and capital costs of the Midstream Facilities, including AFUDC; and (ii) from ISD and for the balance of the Term, an amount equal to all payment obligations of Shipper under the FTSA for the remaining Term.

“**Transmission Lines**” means the Alaska LNG Project components consisting of the PBU Gas Transmission Line and the PTU Gas Transmission Line.

“**TransCanada**” means TransCanada PipeLines Limited, a federal Canadian corporation.

“**TransCanada Costs**” means those salaries, wages, employee benefits and overhead for the employees and internal contractors of Transporter or its Affiliates to the extent engaged in the development, design, financing, construction and commissioning of the Midstream Facilities.

“**Transporter**” has the meaning specified in the preamble to the PA.

“**Transporter Authorized Amount**” has the meaning specified in Section 5.3(b)(i), as such Transporter Authorized Amount may be increased pursuant to Section 5.3(b).

“**Transporter Capacity**” means Transporter’s share of total capacity available in each Midstream Facility as part of the Initial System, as established and reflected in the relevant Key Project Agreements to which Transporter is a party (including any Key Project Agreements addressing gas balancing and related capacity issues).

“**Transporter Condition**” has the meaning specified in Section 3.2.

“**Transporter Conveyance Mechanics**” means those provisions outlined in Schedule F.

“**Transporter Development Costs**” means, without duplication of any AKLNG Development Costs, all costs and expenses (including TransCanada Costs) incurred by Transporter through:

- (a) Transporter’s role as sponsor or equity participant in the Alaska LNG Project and all associated costs and expenses not otherwise considered AKLNG Development Costs (including costs incurred for regulatory strategy and Regulatory Approvals, securing financing or acquiring lands or rights-of-way for the Alaska LNG Project);
- (b) development of the PA and FTSA and all other related agreements in respect of the Services;

Confidential and Proprietary pursuant to AS 38.05.020(b)(12), a provision of SB 138 (2014).

- (c) development of all other agreements between Transporter and the State and their respective Affiliates in respect of the Alaska LNG Project (including governance or equity option agreements);
- (d) participation in the development of the Pre-FEED JVA, FEED Agreement, and the Project Agreements to which Transporter or its Affiliates is a party, which are not otherwise described in paragraphs (a), (b) or (c) of this definition;
- (e) development of, participation in, and prosecution of, the Regulatory Approvals described in and contemplated by Section 2.2;
- (f) carrying out of administration and reporting obligations to and with Shipper pursuant to the PA, FTSA and all other agreements between Transporter and Shipper and their respective Affiliates;
- (g) governmental relations in respect of the Alaska LNG Project, including presentations to, and discussions with, the State and the Alaska Legislature as requested by Shipper or the State;
- (h) business development activities in respect of the Midstream Facilities or the Services, including shipper (other than Shipper) solicitation and other engagement activities (for greater certainty, any costs associated with such business development activities in respect of an Incremental Expansion (as described in Part 20 of Schedule B) shall be allocated to such Incremental Expansion upon the in-service date of such Incremental Expansion);
- (i) cooperation and coordination with AGDC regarding the Alaska LNG Project;
- (j) establishment and administration of Transporter and the Services, including the costs of the general partner of Transporter in administering Transporter's affairs; and
- (k) the administration or termination of AGIA or the AGIA License.

For purposes of calculating the Development Cost Amount pursuant to Section 4.3(a) on expiration or termination of the PA, the Transporter Development Costs shall not exceed the Transporter Authorized Amount then in effect.

“Wilful Misconduct” means any act or failure to act (whether sole, joint or concurrent) by Senior Supervisory Personnel of Transporter, which was voluntary and was intended to cause harmful consequences such Person knew would have on the safety or property of another Person, provided that Wilful Misconduct does not include any act or failure to act insofar as it: (i) constituted Gross Negligence or mere ordinary negligence; or (ii) was done or omitted in accordance with the express instructions or approval of the other Party.

“WP&B” means, in relation to the AKLNG Development Costs, a work program and budget pursuant to the Key Project Agreements whereby Transporter or its Affiliates incur AKLNG Development Costs.

“WP&B Decision Date” has the meaning specified in Section 5.3(a)(i).

“WP&B Notice” has the meaning specified in Section 5.3(a)(i).

Section 2 – Certain Rules of Interpretation

In the PA:

- (a) **Article/Section References:** References to “Article” or “Section” mean the specified Article or Section of the PA, and the word “Schedule” refers to schedules to the PA, unless the PA specifies otherwise.
- (b) **“Herein”:** The PA uses the words “herein,” “hereof,” and “hereunder” and words of similar import to refer to the PA as a whole and not to any provision of the PA.
- (c) **Number and Gender:** Unless the context otherwise requires, words importing the singular include the plural and vice versa and words importing gender include all genders.
- (d) **Uses of Certain Words:** The word “including” (and, with correlative meaning, the word “include”) means including, without limiting the generality of any description preceding that word. The words “shall” and “will” are used interchangeably in the mandatory and imperative sense. The word “may” means is authorized or permitted to, while “may not” means is not authorized or permitted to. The word “knowledge” (and, with correlative meaning, the word “known”) means actual knowledge of a fact, rather than constructive knowledge of a fact.
- (e) **Generally Accepted Meanings:** Words, phrases, or expressions that are not defined in the PA but that have a generally accepted meaning in the practice of measurement and metering in the international businesses of production, transportation, distribution, and sale of gas have that meaning in the PA.
- (f) **Time Periods:** The word “day” means one of Monday through Sunday of each week including legal holidays. Unless otherwise specified, time periods within or following which any payment is to be made or act is to be done shall be calculated by excluding the day on which the period commences and including the day on which the period ends and by extending the period to the next Business Day following if the last day of the period is not a Business Day.
- (g) **Statutory references:** A reference to a statute includes all regulations made pursuant to such statute and, unless otherwise specified, the provisions of any statute or regulation which amends, supplements or supersedes any such statute or any such regulation.
- (h) **Governmental references:** A reference to a governmental official, agency, board, bureau, commission, department, or other instrumentality thereof continues to apply regardless of any changes in name or title, and applies to the successor official, agency, board, bureau, commission, department, or other instrumentality thereof to which the referenced responsibilities or functions may be transferred. Reference to a government official includes the official’s designee.
- (i) **No Strict Construction:** The language used in this PA is the language chosen by the Parties to express their mutual intent, and no rule of strict construction shall be applied against any Party.
- (j) **Derivative Terms:** Where a term is defined herein, a capitalized derivative of such term shall have a corresponding meaning unless the context otherwise requires.
- (k) **Headings:** Headings of Articles and Sections are inserted for convenience of reference only and shall not affect the construction or interpretation of the PA.

Confidential and Proprietary pursuant to AS 38.05.020(b)(12), a provision of SB 138 (2014).

- (l) **Numerical Conflicts:** In the event of a conflict between a written numerical reference and its corresponding parenthetical numeric reference, the written numerical reference shall govern.
- (m) **Consent:** Whenever a provision of the PA requires an approval or consent and such approval or consent is not delivered within the applicable time limit, then, unless otherwise specified, the Party whose consent or approval is required shall be conclusively deemed to have withheld its approval or consent.
- (n) **Currency:** Unless otherwise specified, all references to money amounts are to the lawful currency of United States of America.
- (o) **Time:** Time is of the essence in the performance of the Parties' respective obligations.

SCHEDULE B
FTSA Term Sheet

All of Schedule B is commercially sensitive for TransCanada and has been redacted on the basis that the State of Alaska intends to issue a Notice of Termination to TransCanada Alaska Midstream LP once an appropriation to pay TransCanada has been approved. In such case there will be no FTSA and so this Schedule B is not relevant.

SCHEDULE C
Negotiated Rate Principles

All of Schedule C is commercially sensitive for TransCanada and has been redacted on the basis that the State of Alaska intends to issue a Notice of Termination to TransCanada Alaska Midstream LP once an appropriation to pay TransCanada has been approved. In such case there will be no FTSA and so this Schedule C is not relevant.

SCHEDULE D
Creditworthiness Requirements

All of Schedule D is commercially sensitive for TransCanada and has been redacted on the basis that the State of Alaska intends to issue a Notice of Termination to TransCanada Alaska Midstream LP once an appropriation to pay TransCanada has been approved. In such case there will be no FTSA and so this Schedule D is not relevant.

Confidential and Proprietary pursuant to AS 38.05.020(b)(12), a provision of SB 138 (2014).

SCHEDULE E
Books & Records and Audit Protocol

All of Schedule E is commercially sensitive for TransCanada and accordingly has been redacted.

SCHEDULE F
Transporter Conveyance Mechanics

Upon the occurrence of an event giving rise to these Transporter Conveyance Mechanics, the following mechanics shall apply:

- (a) Shipper shall provide Notice to Transporter of its election of either a “Partnership Interest Conveyance” or a “Partnership Asset Conveyance” in the manner outlined in paragraphs (b) and (c) below. For a termination of the PA or the FTSA as described in paragraph (d)(ii) below, such Notice shall be delivered concurrently with payment of the Termination Amount. For a transfer as described in paragraph (d)(i) below, such Notice shall be delivered on such date as is agreed by the Parties in the FTSA.
- (b) If Shipper has elected a Partnership Interest Conveyance, Transporter shall cause an assignment of the Partnership Interests of the TransCanada Limited Partner and General Partner (as such terms are defined in the limited partnership agreement of Transporter) to Shipper or its designee Affiliate, and the general partner of Transporter shall provide written notice to its limited partners of the occurrence of such event (a “**Termination Conveyance Notice**”). The Termination Conveyance Notice shall identify:
 - (i) the event which gives rise to these Transporter Conveyance Mechanics and the provision of the PA or FTSA which grants such conveyance right;
 - (ii) the partner which is obligated to make the transfer and the partner (or its Affiliate designee) that has the right to receive the transfer of a partnership interest in Transporter (the “**Partnership Interest**”); and
 - (iii) the price for the Partnership Interest to be transferred, which is determined in accordance with paragraph (d) below.
- (c) If Shipper has elected a Partnership Asset Conveyance, assign or transfer to Shipper (or its designee Affiliate) (which items are, collectively, the “**Conveyance Assets**”):
 - (i) all of its interest in either the Pre-FEED JVA or the FEED Agreement, whichever is then in force, in accordance with the provisions of such agreement;
 - (ii) any equity participation interest in the Alaska LNG Project and the Midstream Facilities pursuant to any Project Agreement then in force, in accordance with the provisions of such agreement; and
 - (iii) such other assets of Transporter as are used and useful in respect of the Midstream Facilities.
- (d) The transfer price for the Partnership Interest or the Conveyance Assets (as applicable) to be transferred shall be determined as follows:
 - (i) with respect to transfers resulting from the Buy-Back Right and the Put Option as set forth in FTSA Terms, the transfer price shall be equal to the End of ICT Purchase Price; and
 - (ii) with respect to transfers resulting from a termination of:
 - (A) the PA under Section 4.4, or

- (B) the FTSA prior to FID under the provisions of the FTSA giving effect to part 6 of Schedule B;

the transfer price shall be \$1.00.

- (e) In addition to payment of the transfer price as described in paragraph (d) above, Shipper (or its designee Affiliate) shall reimburse Transporter (in the case of a Partnership Asset Conveyance), or the transferring Entity of the Partnership Interest for all reasonable costs and expenses incurred by such Entity in giving effect to the transfer contemplated by these Transporter Conveyance Mechanics, including all legal fees and all costs and expenses associated with (i) complying with the requirements of any of the Key Project Agreements, including obtaining any required consents or approvals; and (ii) obtaining any Regulatory Approvals in respect of such transfer. Such costs and expenses may be audited by Shipper in accordance with the Audit Protocol for a period of 1 year following the closing date of the purchase and sale transaction.
- (f) For greater certainty, any such assignment shall be made to Shipper:
- (i) in the event of a Partnership Interest Conveyance, after the TransCanada Limited Partner (as defined in the limited partnership agreement of Transporter) has received its share of any distributions related to the Termination Amount, and
- (ii) promptly, and shall not be delayed until final resolution of any Dispute pursuant to Section 4.3(c) of the PA or comparable provision of the FTSA. Any amounts payable to Transporter in relation to the resolution of such Dispute shall result in a corresponding increase to the transfer price by way of post-closing adjustment.
- (g) The proceeds shall be payable by the Shipper or its Affiliate designee receiving the transfer of Partnership Interest from the transferring Partner or receiving the Conveyance Assets from the Transporter, as applicable.
- (h) In the event of a Partnership Interest Conveyance, the Termination Conveyance Notice shall contain such other terms and conditions as are necessary or appropriate in connection with the transactions contemplated therein, provided that none of such terms and conditions shall conflict in any way with the provisions of these Transporter Conveyance Mechanics, the PA, the FTSA or any Key Project Agreements to which Transporter is a party.
- (i) The applicable purchase and sale agreement shall be prepared on terms customarily included in similar transactions and agreed upon by the Persons involved such transaction. Any such assignment shall be made on an "as is, where is" basis, without representation or warranty of any kind by the relevant assigning Entity, subject only to a reasonable representation and warranty by such assigning Entity as to its title or right to transfer such items free and clear of any liens and encumbrances other than those liens and encumbrances as would typically be allowed in respect of comparable transferred interests.
- (j) The completion of the purchase and sale transaction pursuant to this Schedule F shall take place at Houston, Texas on the date no later than the number of days specified below after (1) the Termination Conveyance Notice (in the case of a Partnership Interest Conveyance), or (2) payment of the Termination Amount :
- (i) 120 days for a conveyance in respect of those provisions of the FTSA corresponding to parts 4 or 5 Schedule B; or

(ii) 30 days for a conveyance in respect of a notice delivered under Section 4.4;

provided, however, that if any Regulatory Approval or waiting period is required in connection with any such transfer, then such period shall be extended by the number of days necessary to satisfy such regulatory requirement. If such day is not a Business Day, the closing shall occur at the same time and place on the next succeeding Business Day.

(k) For greater certainty, any assignment made pursuant to these Transporter Conveyance Mechanics shall be subject to (i) any restrictions contained in the Key Project Agreements and (ii) those matters outlined in Section 2.2(c) of the PA (or equivalent provision of the FTSA).

SCHEDULE G

Illustrative FTSA Table of Contents

All of Schedule G has been redacted on the basis that the State of Alaska intends to issue a Notice of Termination to TransCanada Alaska Midstream LP once an appropriation to pay TransCanada has been approved. In such case there will be no FTSA and so this Schedule G is not relevant.



**STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU**

**Questions and Answers:
House Finance - 3 pm - October, 25 2015**

Representative Neuman:

What are the problems with TC? What are the issues? Are they good or bad?

Department of Natural Resources(DNR) Response:

As Deputy Commissioner mentioned during testimony, some of the issues the State has experienced with TransCanada center around some of the governance issues and access to information. However, the State would like to emphasize that TransCanada is a world-class pipeline company and the State has not found any fault with the technical expertise provided to the State.

If TC remains in the Alaska LNG Project, they could demand independent control over the midstream segment of the project going forward, which will likely lead to a misalignment of expectations and wants because TC answers to its shareholders versus the citizens of Alaska.

Without TC, access to information will still require AGDC to be the conduit between the Project and the State, but now AGDC will have access to all aspects of the project (including midstream). Furthermore, voting will be through AGDC but AGDC does answer to the State and its citizens in many ways and will therefore not be "independent" in the same way as TC would have been.

Representative Thompson:

Who is the state gas team? What role do they play? How do they interact with AGDC?

DNR Response:

The State Gas Team (SGT) consists of personnel from the Department of Natural Resources (DNR), and in particular personnel from the North Slope Gas Commercialization (NSG) component, the Department of Revenue (DOR) and Department of Law (DOL) and the Office of the Governor. The team provides the administration with in-house capacity for consistent support and well-informed advice throughout the negotiation and crafting of critical commercial agreements related to the Alaska LNG Project. The SGT also consists of subject matter experts within these agencies and external consultants.

The AKLNG state gas team is primarily responsible for:

- Negotiating critical commercial agreements for the Alaska LNG Project with the Producer parties (ExxonMobil, BP, and ConocoPhillips);
- Developing a plan to market and dispose of the State's share of project gas for in-state use and LNG exports;
- Evaluating, and if it's in the best interest of the State, modify existing lease structures to accommodate the State taking tax-as-gas and royalty in-kind;
- Negotiating Property Tax for the Payment in Lieu of Taxes (PILT) and Impact Payments during construction;
- Assuring the project allows for adequate expansion for new discovery and alternative gas supplies; and
- Assuring the pipeline is adequately designed to provide supply to meet in-state gas demand (demand is determined by the Alaska Gasline Development Corporation).

The State Gas Team coordinates with AGDC on a number of different levels:

- AGDC serves as the SGT's conduit for accessing AKLNG Project technical information developed by the Houston-based AKLNG Project Team
- SGT and AGDC conduct bi-weekly meetings to coordinate on aspects of providing AKLNG gas for in-state use
- SGT provides AGDC with technical information on Upstream gas supply to support the engineering analysis of the project's technical design basis

Representative Neuman:

Is there anything that lines out who the players are?

DNR Response:

Organization Chart provided on 10/26/15 (attached).

Representative Guttenberg:

Costs that incurred as project expenses, are they passed on to TC or does the state cover them? What is the timeline if we terminate before TC terminates? Or if they terminate first?

DNR Response:

Refer to "TC Right to Terminate and Effect of Termination" distributed on 10/26/15 (attached).

Representative Neuman:

We need a chart that lines this out. If the state terminates vs if TC terminates

DNR Response:

Refer to "TC Right to Terminate and Effect of Termination" distributed on 10/26/15 (attached).

Representative Neuman:

I would like to know where we are in negotiations and I would like it in writing.

DNR Response:

Active negotiations among the State, AGDC and the Producers (with the parties varying depending on the nature of the agreement) are currently underway on the following commercial agreements and issues. As these negotiations include proprietary and confidential terms and conditions, additional details on these agreements and issues will be provided as negotiations are completed.

- Fiscal agreement
- Governance agreement
- Gas supply/balancing agreement
- Expansion and Access terms
- Withdrawal agreement
- Gas Sales by Withdrawing Parties agreement
- Byproduct Handling Agreement/Terms (including treatment of CO₂)
- Lease Modifications/Conversions
- Joint Venture Marketing Agreement(s) and/or Producer offers to purchase RIK gas per SB 138
- Aspects of the System Use Agreement (including Capacity Release provisions for imbalance management)
- Agreement on pro rata obligation to provide for utility Domestic Gas needs on reasonable terms (e.g., no requirement for AGDC to make long-term take-or-pay commitments)

A number of commercial agreements necessary to inform the RIK/RIV decision cannot be finalized until the details of a gas balancing agreement have been resolved because there are key inter-dependencies. These include upstream and information sharing agreements, and aspects of governance and system use agreements, especially as they relate to capacity entitlement and capacity release.

Representative Gattis:

Will it take longer than 120 days to buy TC out?

DNR Response:

We do not anticipate that it will take longer than 120 days to buy out TransCanada. Furthermore, it is not the intent of DNR or TC to drag out the closing of the buyout. Both DNR and TC are willing to amend existing contractual arrangements to reasonably meet the needs of the parties.

Representative Gattis:

Are we currently auditing or will we have to back track?

DNR Response:

DOR has not begun auditing any of the expenditures but the process for audits of TC's development costs are contained in the Precedent Agreement Article 4.3(c). Article 4.3 of the Precedent Agreement outlines the requirements necessary in case of a termination. DOR is in the process of procuring services for that audit and working with TransCanada. From an accounting perspective, until we give a notice of termination or receive a termination notice, an audit would not begin. Once Notice is given, the State has 30 days to perform the audit process in accordance with the provisions established in the current PA

DOR Responses to additional auditing questions:

Is there time built into the PA's billing/payment process for the audit of numbers and does it trigger any delays to payment timing requirements?

Yes. The current PA sets out the auditing process and payment timing requirements. The State has not been provided the actual termination amount or any supporting documentation. This information will be provided when the Notice of Termination is submitted.

If we need to challenge TC's numbers, what is the process and, again, how does it affect payment timing?

Under the PA, TC's costs are challenged as part of the audit process. Any disputed amounts by the State are placed into an escrow account set up by the parties. Disputed amounts are determined through executive level dispute resolution process and paid within 30 days. Unresolved issues are tried in Alaska courts.

TransCanada's AKLNG Participation



Marty Rutherford
Deputy Commissioner, DNR
Deepa Poduval
Director, Black & Veatch



October 25, 2015

Executive Summary

Background

- In June 2014, the State of Alaska (SOA) and TransCanada Alaska Midstream LP (TransCanada) entered into a key agreement authorizing TransCanada to pay the upfront capital costs and hold the State's 25 percent share of ownership in the midstream components of the Alaska LNG (AKLNG) Project. These midstream components are the Gas Treatment Plant (GTP) and pipeline portions of the overall project.
- The agreement, called the Precedent Agreement (PA), was based on terms of a Memorandum of Understanding (MOU) between the State and TransCanada signed in December 2013. While the Alaska Legislature was not a party to the PA, it reviewed and debated the terms of the MOU during the 2014 legislative session.

Decision at hand

- The State is now faced with a December 31, 2015 deadline to make a decision on whether to take back TransCanada's share and have direct equity participation in the AKLNG midstream. To do so would require termination of the PA.
- Under the PA's terms, by December 31, 2015, the State is obligated to either enter into a Firm Transportation Services Agreement (FTSA) with TransCanada or TC will be able to terminate the PA. Alternatively, if agreeable to TransCanada, the State can negotiate to extend the date for entering into an FTSA beyond December 2015.

Recommendation

- The State administration recommends termination of the TransCanada relationship by December 2015 and replacing it with the State's direct participation in the AKLNG midstream.
- The State administration expects this path to allow the State to better manage the obligation the State has for AKLNG midstream costs whether or not the project proceeds, increase the overall economics of the project to the State, and allow the State to have more direct voting rights on key AKLNG issues in return for its investment.

BACKGROUND OF STATE'S PRECEDENT AGREEMENT WITH TRANSCANADA

Context for State's 2014 decision to enter into a Precedent Agreement (PA) with TransCanada (TC)

- **AGIA framework:**
 - TransCanada was the State's licensee under AGIA
 - AGIA work product could not be transferred to AKLNG until after resolution of AGIA abandonment issues (including cost of the work product)
 - AGIA also contained a treble damages provision
 - It was in this context that the prior Administration negotiated an MOU with TC in 2013, and the AGIA Termination Agreement in 2014, to exit AGIA, transition to AKLNG, and sign the PA with TC
- **Entering into the PA with TC**
 - Gave the State a clean off ramp from the TC relationship, now, which it did not have when it entered into the PA for all the reasons discussed above
 - Gave the State time during pre-FEED to begin to develop its in-house capabilities in order to fully consider the option of participating directly in midstream at appropriate off-ramps
 - TC's work on AGIA and APP allowed smooth transition into pre-FEED
 - Entering into the PA with TC for pre-FEED also gave the State time to assess its ability to finance its share of investment in AKLNG without TC

Key terms of the Precedent Agreement between State of Alaska & TransCanada



TC Owns the State's ~25% Entitlement to GTP + Pipeline
Funds up front midstream cash calls
Technical lead for pipeline during pre-FEED

State to Commit to 20-25 Year Transportation Agreement with
TC by Dec 2015 to Pay for Using GTP+Pipe



SOA Ultimately pays TC for all its Costs
(including a cost of capital of ~7%)

Both SOA and TC have Milestones & Off Ramps:
SOA Responsible for TC Costs, Regardless of Off Ramps



The Precedent Agreement has agreed upon off-ramps that allows the State to terminate before December 31, 2015

PROJECT STAGE:	PRE-FEED	FEED	FID	CONSTRUCTION
TIMELINE:	2014-2016	2016-2018		2019-2026
PERCENT SPEND:	~1%	~5-6%		~93-94%

OFF RAMPS:

Termination Dec. 31, 2015
 Pay TC Dev. Costs of ~\$70M²
 (Incl. TC Internal Costs³)
 SOA also responsible for remaining GTP and Pipeline Pre-Feed costs from Jan-June 2016 of ~\$61M⁴

Termination Dec. 31, 2018
 Pay TC Dev. Costs of ~\$490M
 (Incl. TC Internal Costs³)

¹ Assumes 25% State equity participation

² \$70M estimate incorporates a \$4M credit for an SOA payment to TC for AGIA reimbursement

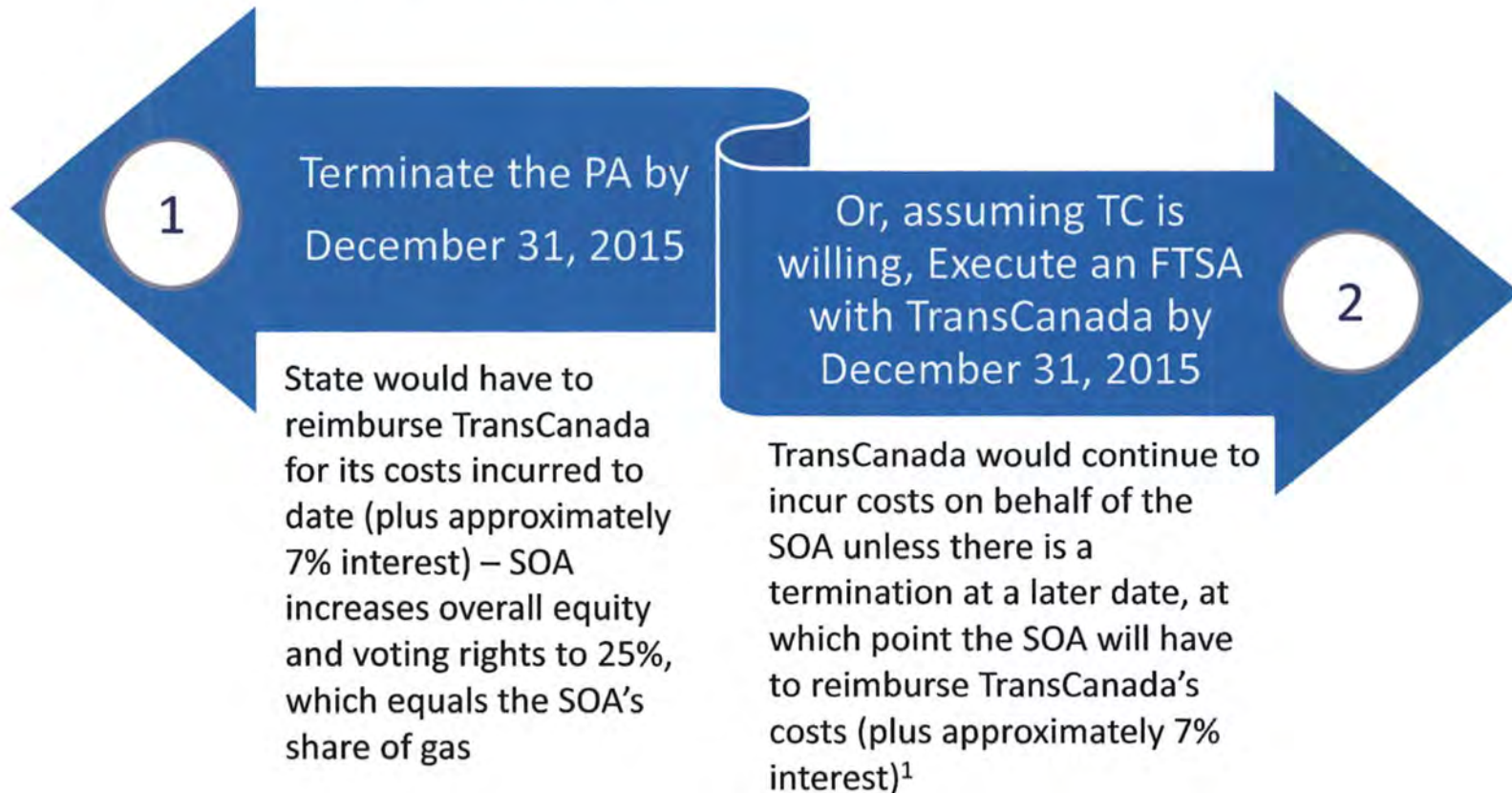
³ TC Internal costs include AFUDC and Internal Management Fees

⁴ Provided by AGDC based on current approved WP&B for AKLNG and includes an additional 30% contingency

**WHAT IS THE DECISION AT
HAND?**

The SOA is faced with the strategically important decision of whether to terminate the Precedent Agreement with TransCanada

The State has two main options:



¹ The State also has a third option, assuming TC is willing: exercise its option to acquire 40% of the equity of the TransCanada entity that will own the 25% of the AKLNG midstream. This option is not discussed in this primer but in general it has many of the same pros and cons associated with option 2 above.

The administration recommends Termination of the Precedent Agreement

Alignment

Currently, the SOA is estimated to receive 25% of the gas from Project; however, with TransCanada's equity participation in the midstream portion of the Project, the SOA only retains approximately 12.5% equity in the project

Voting Rights

Terminating the agreement and increasing the State's voting rights would allow the State to have a more direct say in the decision making process of the project

Economic Benefit

The SOA could realize up to \$400 million of additional annual net cash flows from the Project, based on DOR's expectations of State being able to finance cheaper than TC by financing the midstream portion of the Project directly

**WHY ARE EQUITY
ALIGNMENT & VOTING
RIGHTS IMPORTANT?**

State does not have direct voting rights for GTP or pipeline

		EM	BP	CP	SOA	Total	
UPSTREAM	Gas	32%	21%	22%	25%	100%	
	PBU/PTU						
MIDSTREAM/DOWNSTREAM		=	=	=	=	=	
	AKLNG Equity & Capacity	GTP	32%	21%	22%	25% <small>CURRENTLY HELD BY TC</small>	100%
		Pipeline	32%	21%	22%	25%	100%
		LNG	32%	21%	22%	25%	100%

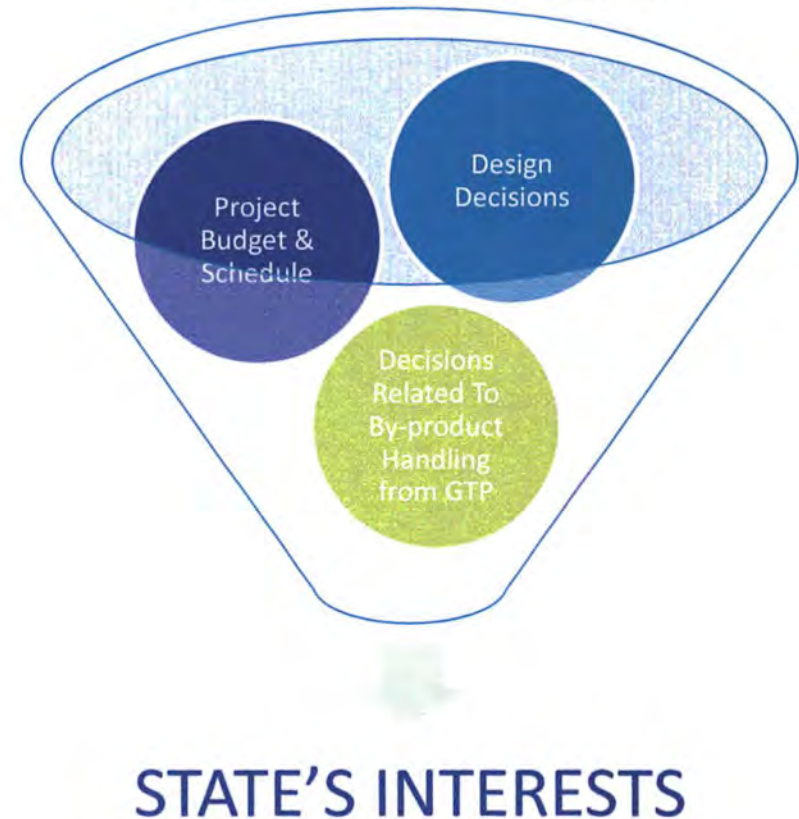
PRODUCER SHARE OF GAS IS EQUAL TO PRODUCER EQUITY SHARE IN AKLNG
SOA SHARE OF GAS IS NOT EQUAL TO SOA EQUITY SHARE IN AKLNG

Note: All ownership shares shown are approximate and State equity participation is based on production mix from PBU and PTU and the State's royalty share from each field; State equity participation is currently expected to equal 24-25%

Alignment through direct participation will facilitate State influence equivalent to its investment

- TC's decisions driven by shareholder value; not always the same as SOA interests
- Governance and voting rights issues for State's share of project are more complex with TC:
 - TC votes on GTP and pipeline issues and AGDC votes on LNG issues?
 - Share voting rights on issues that impact the whole project?
 - Who speaks for the State?

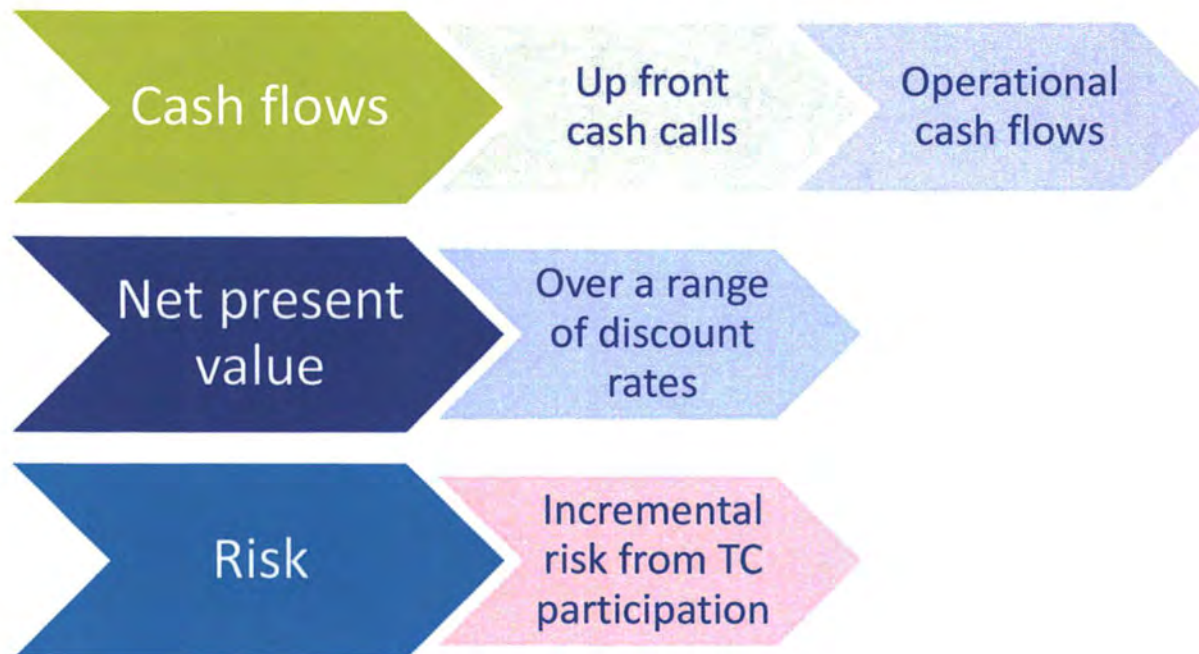
KEY AREAS WHERE ALIGNMENT IS CRITICAL TO STATE INCLUDE:



**WHAT IS THE ECONOMIC
IMPACT OF THE TC
DECISION FOR THE STATE?**

Criteria for evaluating economic impact of TC Participation on SOA

CRITERIA FOR SOA IMPACTS



What are the State's up front cash calls required in the project for the State if the agreement is terminated?

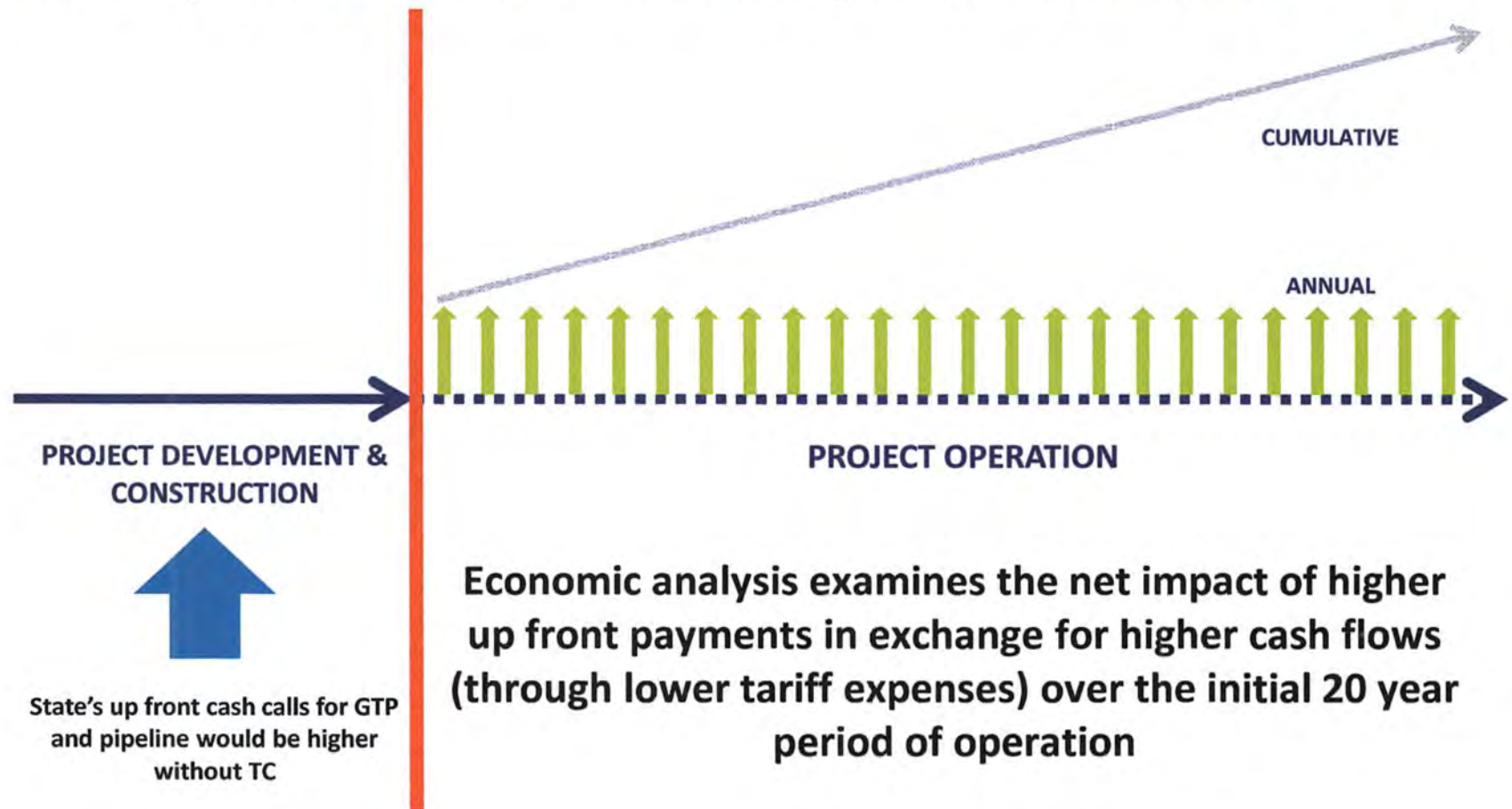
\$ Millions	SOA Current Up Front Cash Calls w/ TC	SOA Up Front Cash Calls w/o TC	Total
TC Termination Amount	-	~\$70 ¹	~\$70
AGDC Pre-FEED ²	~\$66	~\$61	~\$127
FEED	~\$365	~\$310	~\$675
Construction ³	~\$6,500 - \$7,900	~\$6,500 - \$7,800	~\$13,000 - \$15,700

¹ TC Termination Amount includes TC Internal Costs (AFUDC + Management Fees) and a credit of ~\$4M for SOA payment to TC for AGIA reimbursement

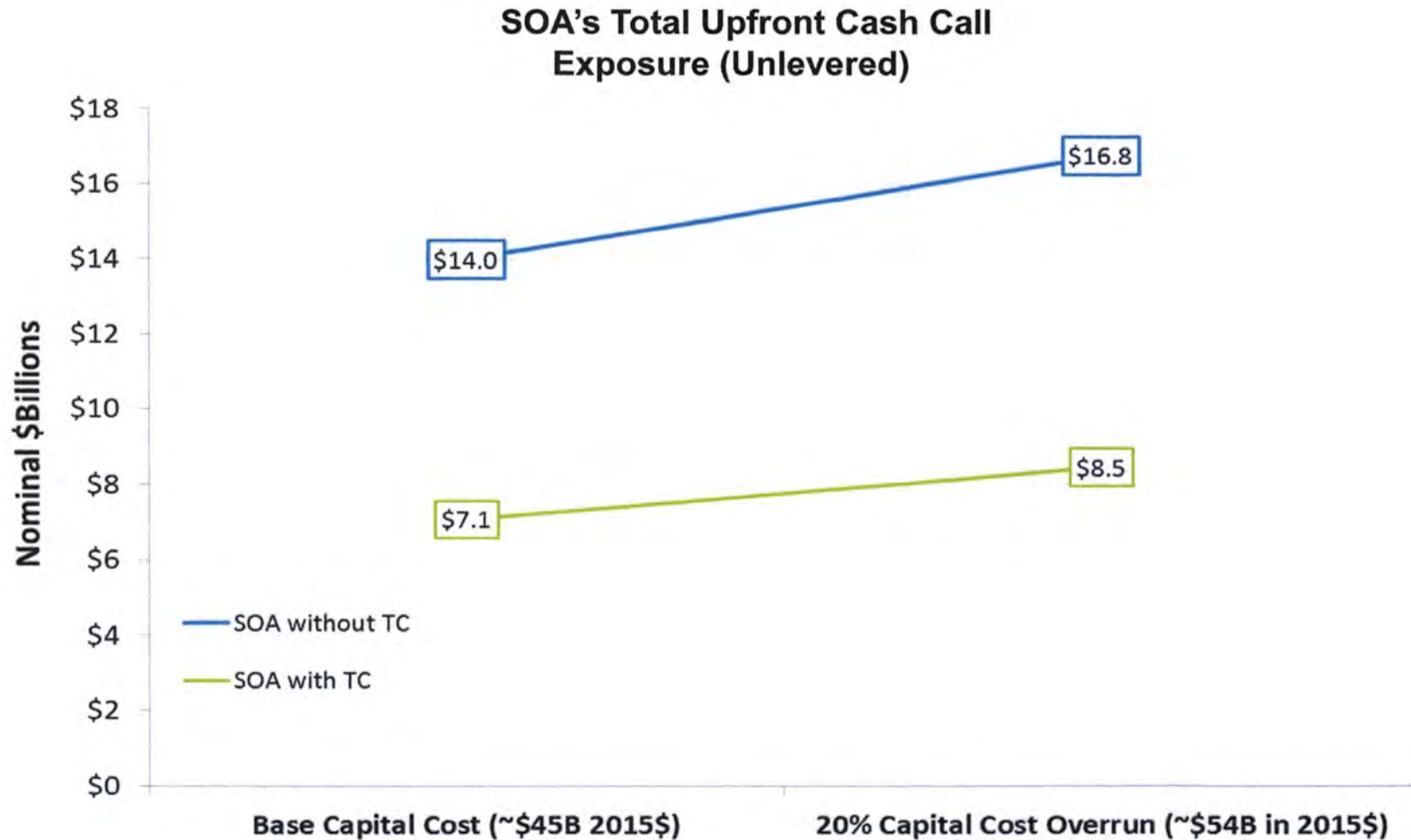
² Provided by AGDC based on current estimated WP&B for AKLNG. Includes prior AGDC pre-FEED appropriations.

³ Range of costs is based on current estimates to 20% cost overrun
 Note: Estimates do not include AGDC internal costs or agency fees

Economic impact to the State is driven by a trade-off between higher upfront investment and higher operational cash flows or lower up-front investment with lower operational cash flows

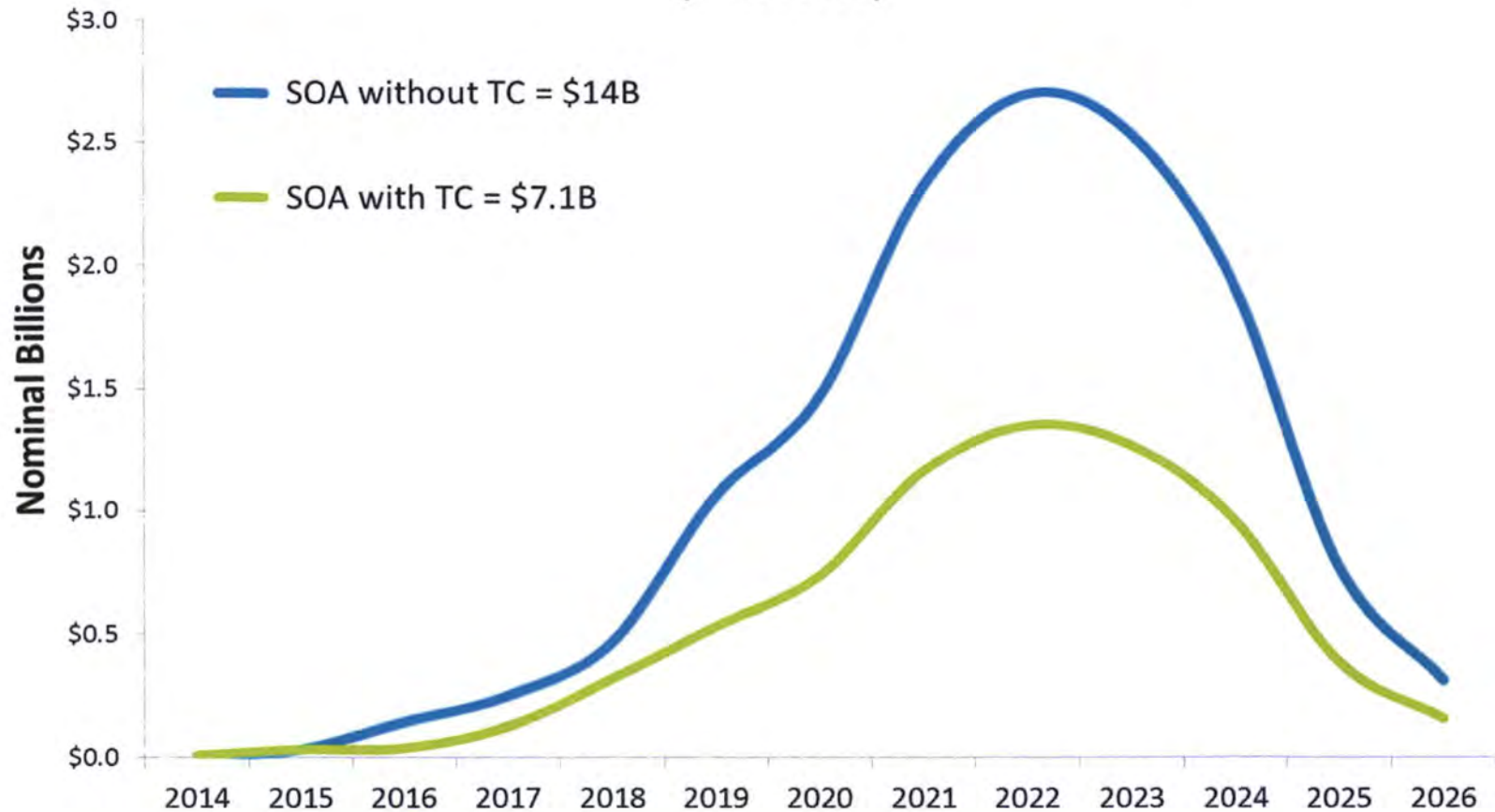


SOA's total upfront cash call exposure is \$6.9-8.3B higher without TC participation

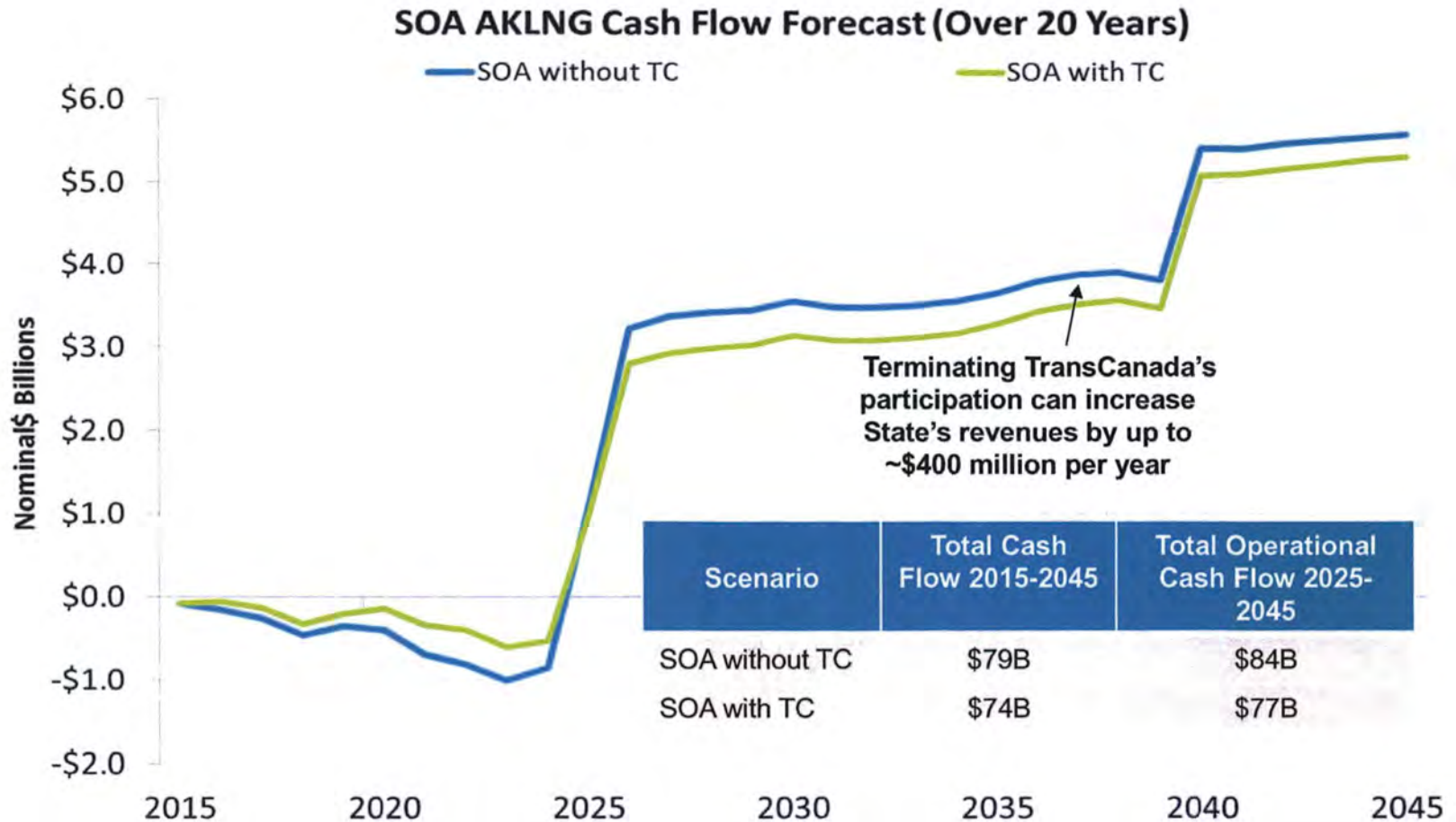


SOA's annual up front cash calls in the AKLNG project are expected to nearly double without TC

SOA's Annual Upfront Cash Call Exposure (Unlevered)



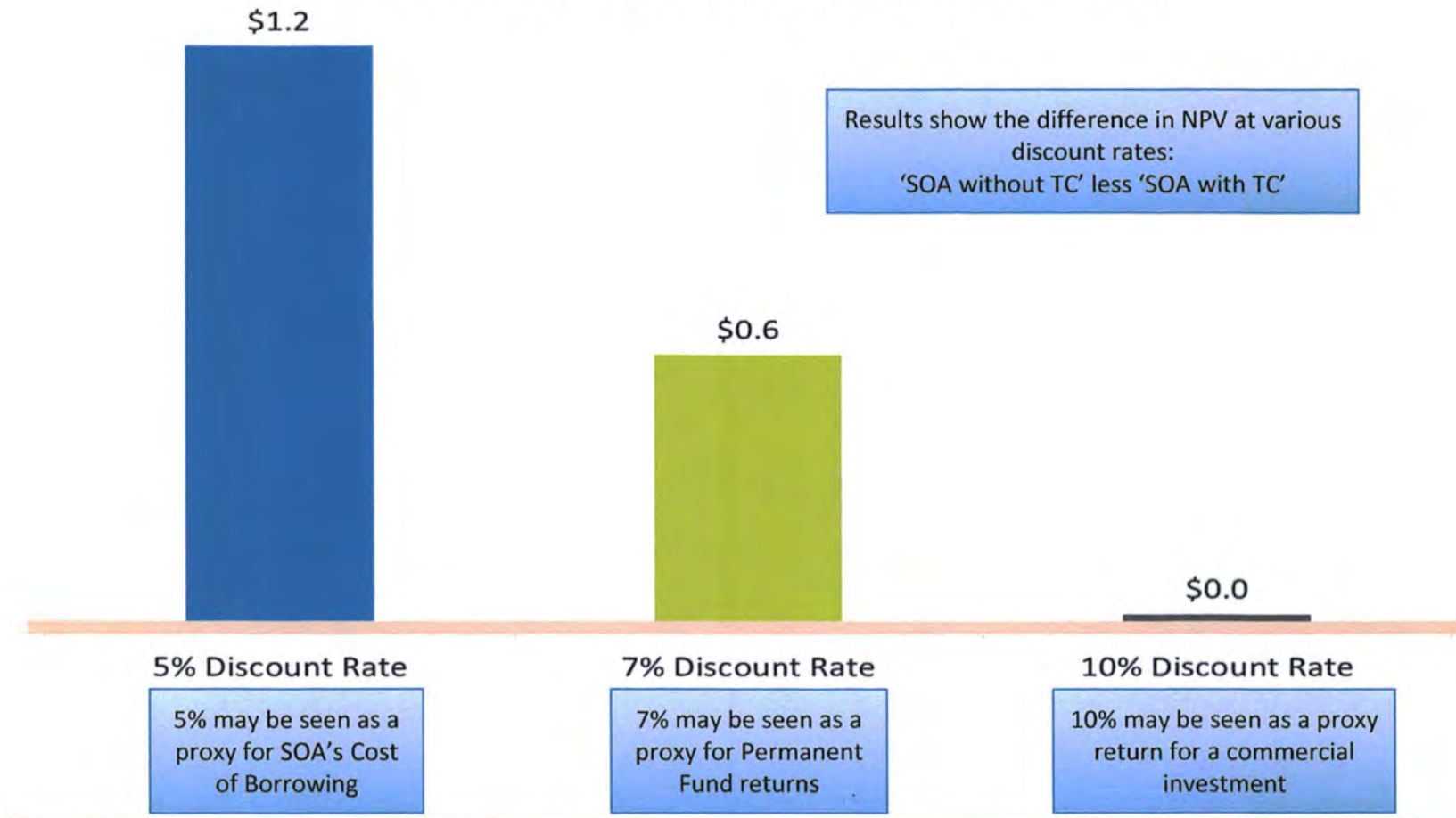
Once operational, SOA is expected to receive annual cash flows of up to ~\$400 million higher without TC¹



¹ Based on DOR's projection that the State can finance its share cheaper than TC

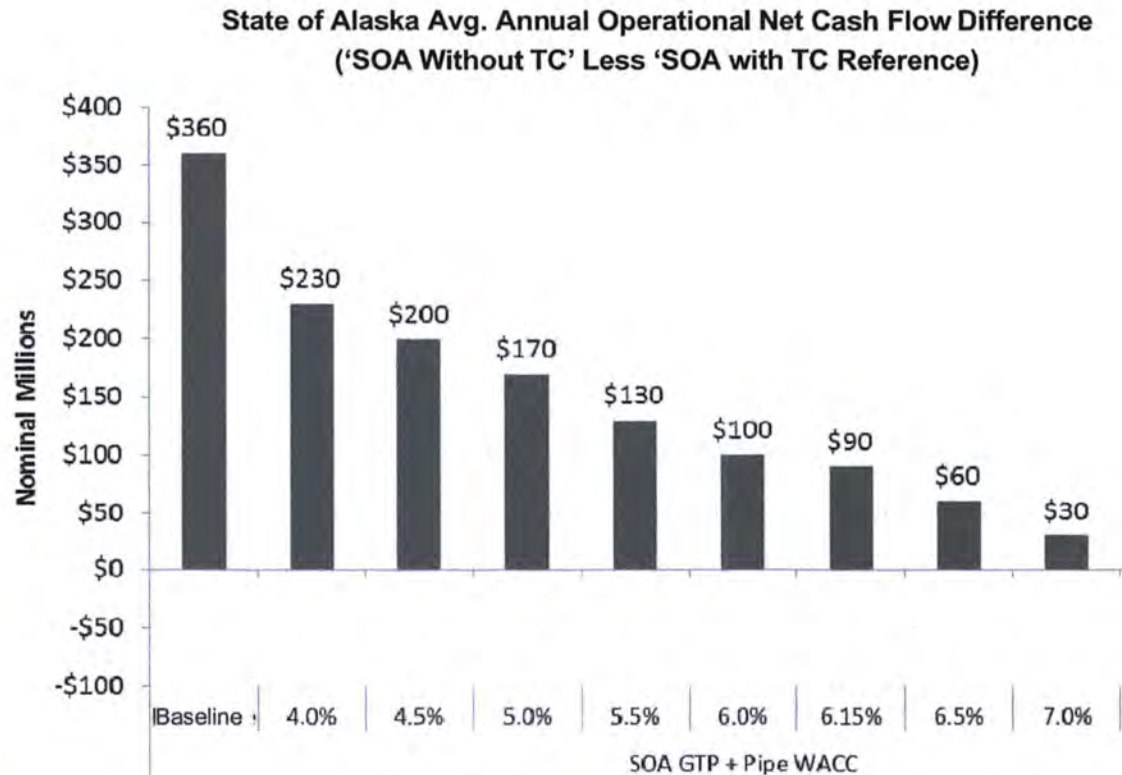
NPV increase to the State without TC can be between \$0-1.2B over 20 years

SOA NPV Increase Without TC (\$2015 Billions)



The economic benefit of replacing TC could vary based on the SOA's credit rating

- The State could potentially achieve up to **~\$400 million incremental annual cash flows**, based on the State's expected lower cost of capital
- The State's cost of capital would increase with any credit downgrades
- Even if the State's credit rating deteriorates and results in a higher cost of capital for the State, it is still expected that the State will achieve additional annual cash flows without TC



TIMING OF DECISION

Why terminate the agreement with TransCanada now?

Manage Financial Risk

- State owes TC its costs plus interests, regardless of project completion
- If project fails: Keeping TC in longer and terminating later means that State would need to make a bigger and more expensive payment later
- If project succeeds: State is expected to be able to finance cheaper than TC, potentially saving hundreds of millions a year

Avoid Back-in Rights

- Unlike the PA, the proposed FTSA is expected to include a commitment to give “back-in” rights for TransCanada, which states that within five years of exercising its termination option, if the State participates in a pipeline project substantially similar to the AKLNG project, the State would need to offer TransCanada an option to participate
- Terminating TC’s participation now would give the State a clean off-ramp without needing to offer any back-in rights

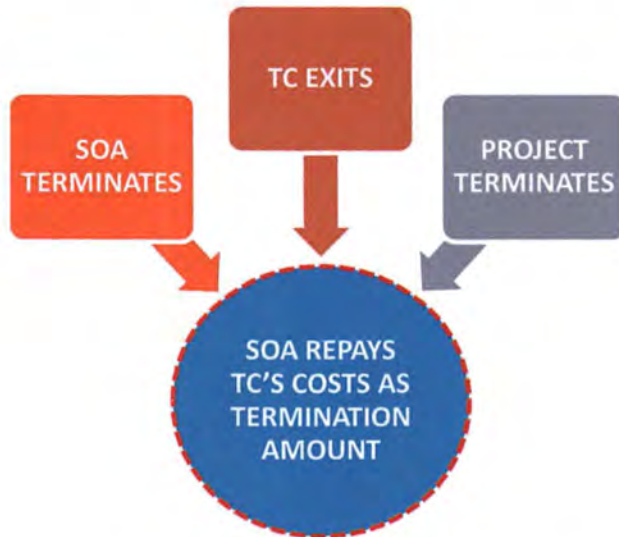
Influence Project Decisions

- As the Project progresses towards the end of the Pre-FEED phase, certain key decisions are slated to be made in the next six months
- Due to fundamental difference between the SOA’s, producers’ and TC’s decision criteria and the, increasing the SOA’s voting rights may allow the SOA to have a more direct say in the decision making process

Per prior agreements, SOA is always obligated to repay TC's costs¹



IF PROJECT DOES NOT MOVES FORWARD WITH TC



> Project development risk is borne by SOA

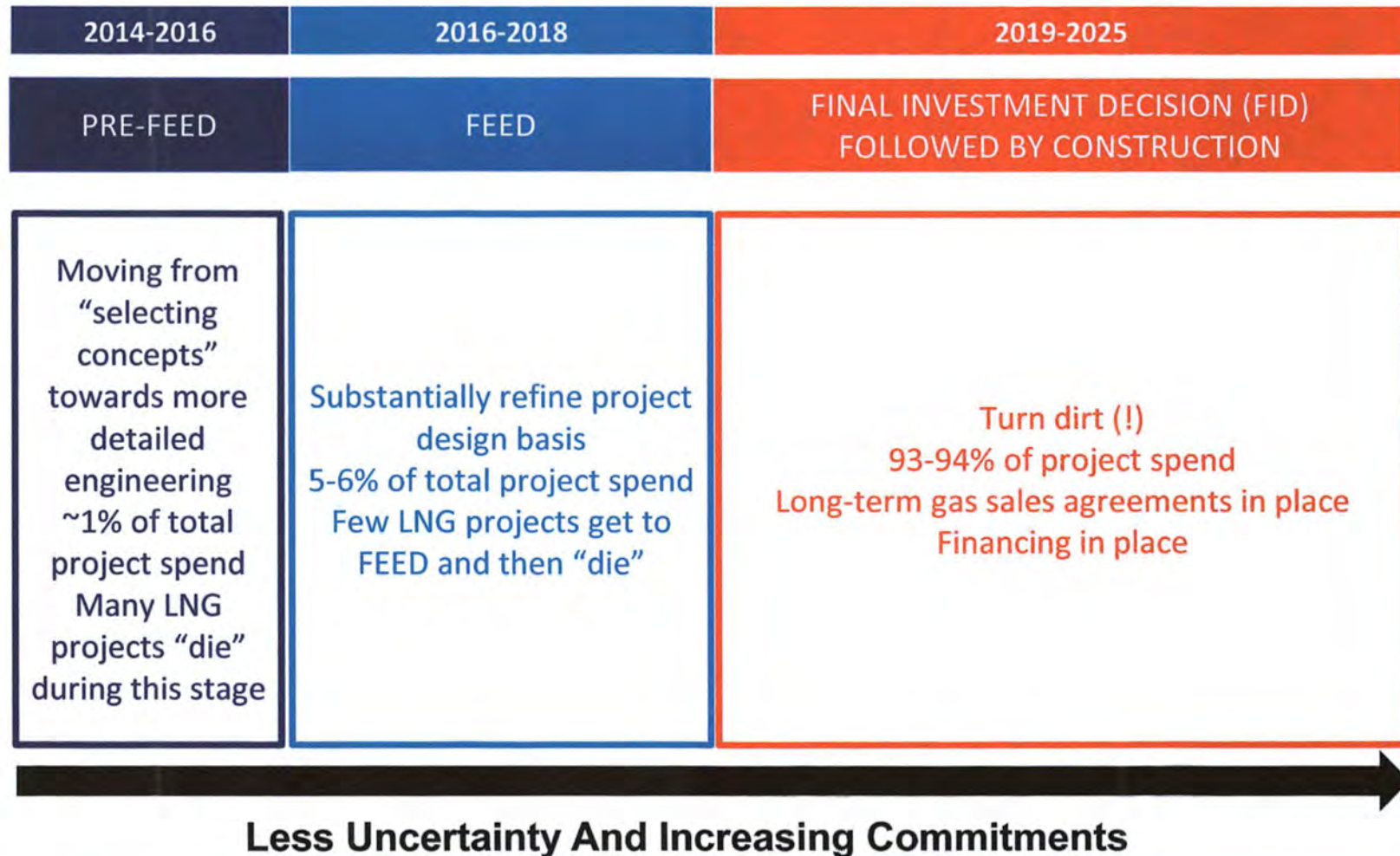
IF PROJECT MOVES FORWARD WITH TC



> SOA pays TC tariff regardless of price or volume risks

¹ TC costs to be repaid include its share of AKLNG work plan and budget, AFUDC, and internal management fees

Stakes get higher as Project proceeds through stage gates



Avoid Back-In Rights for TransCanada

- The proposed FTSA is expected to include a commitment to give “back-in” rights for TransCanada.
- The back-in right states that within five years of exercising its termination option, if the State participates in a pipeline project to commercialize North Slope gas that is substantially similar to the AKLNG project, the State would need to offer TransCanada an option to participate in the GTP and pipelines of that project under similar terms.
- Terminating TC’s participation now would give the State a clean off-ramp without needing to offer any back-in rights.

Influence Key Near-Term AKLNG Decisions

- There is a fundamental difference between the SOA's and the producers' (and potentially TransCanada's) primary decision criteria
 - Lowest cost vs. Most value for Alaskans
- Certain key decisions are slated to be made in the next six months
- By terminating the agreement with TransCanada, the SOA would gain voting rights equal to its gas share and have a more direct influence over key technical decisions related to the midstream such as:
 - By-product handling
 - Project budget
 - Schedule for the midstream portion
- In addition, terminating the PA with TransCanada is expected to facilitate simpler and more efficient resolution of voting rights in AKLNG governance agreements currently being negotiated

**WHAT ARE OPTIONS FOR THE STATE
TO FINANCE ITS SHARE OF
MIDSTREAM AKLNG COSTS
WITHOUT TRANSCANADA?**

What are the options for the State to finance its share of AKLNG Midstream without TransCanada?

- The State will have the following options to pay the TC Termination Amount and finance its share of the Project during the remainder of Pre-FEED, FEED and the construction period¹:
 - The Legislature could appropriate from existing State funds, e.g., the Constitutional Budget Reserve Fund (CBRF), Earnings Reserve Fund, etc.
 - The Legislature could authorize the issuance of State debt
 - The Legislature could authorize pursuit of project financing
 - The Legislature could authorize the pursuit of funding from other sources: LNG buyers and other potential equity investors

¹ These are the same funding options for the LNG Plant if TC remained in the Project

Will termination of the agreement affect the State's credit rating?

FirstSouthwest advises that a decision to terminate the TC's participation will not, in and of itself, result in a downgrade of the State's credit rating:

- No incremental commitments by the State
- As the State's overall costs related to the Project are projected to be reduced without TC (B&V estimates a reduction of up to \$400 million per year), the termination should be viewed by the credit ratings agencies as a net positive for the State
- With or without TC, the State should anticipate a reduction in the State's credit rating during the construction period (when no gas sale revenues are being generated)
- Credit rating should recover once gas sale revenues become established
- TC's exit, by itself, should not result in a credit downgrade during the construction period that is greater than any downgrade if TC remained in AKLNG. The State's credit could instead be improved by the lower costs to the State as a result of TC's exit

**HOW CAN THE STATE REPLACE
TRANSCANADA'S TECHNICAL ROLE
IN THE PROJECT?**

What is TC's technical role in the AKLNG Project?

- TC is experienced in northern pipelines and leads the pipeline technical work for AKLNG

- TC in its current role performs or has performed several functions including the following:
 - Holds State of Alaska's midstream equity in AKLNG as signatory to the JVA
 - Contributes pipeline SMEs that were seconded to the JVA PMT
 - Coordinated FERC NEPA Process

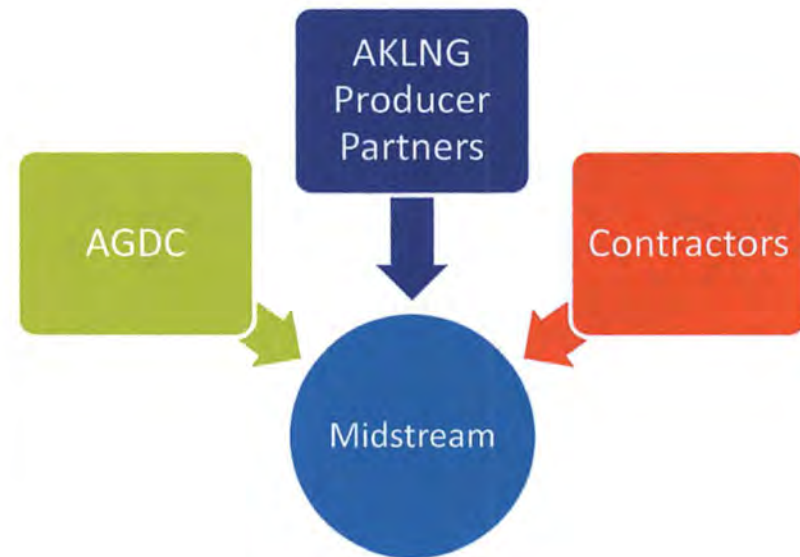
How will TransCanada's technical expertise be replaced?

- TransCanada is not anticipated to build the pipeline, that will be managed through the AKLNG Project Management Team (PMT) which leads and guides the AKLNG project
- PMT consists of Co-Venturer (CoV) employees seconded to project based on experience and skill sets
- PMT hires engineering and specialist contractors to advance design efforts
- Significant amount of work is done by contractors with oversight by PMT

How will TransCanada's technical expertise be replaced?

- AKLNG Project partners bring significant experience
- In addition, AGDC brings Alaska pipeline experience
 - Successfully completed Pre-FEED and FEED on ASAP
 - Key subject matter experts based in Alaska
 - AGDC has already taken over TC's role in coordinating NEPA process


The AKLNG Project partners have worldwide experience and resources to be able to step into the pipeline technical lead role played by TC



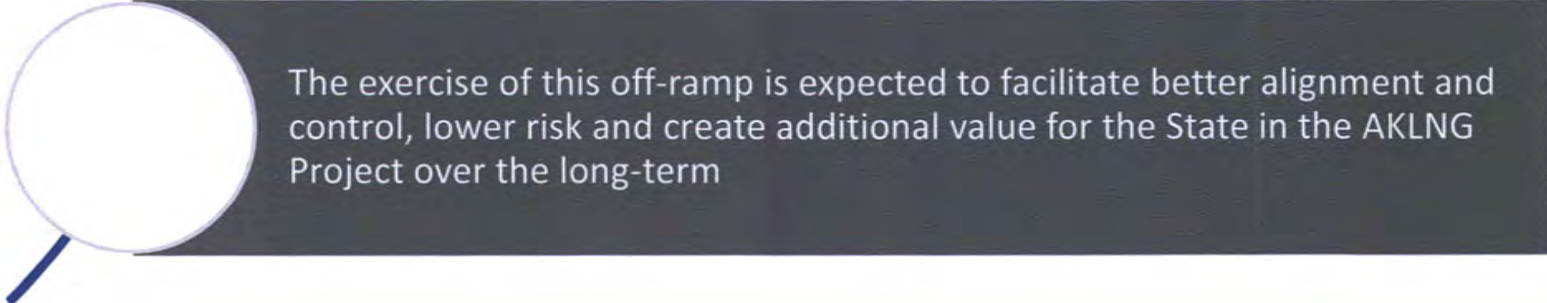
Conclusions & Recommendations



The current arrangement with TransCanada was designed to provide the State (and TransCanada) with several off-ramps as the AKLNG Project moved through its different development stages, including an important clean off-ramp for the State in December 2015



The State administration recommends termination of the TransCanada relationship by December 2015 and replacing it with the State's direct participation in the AKLNG midstream



The exercise of this off-ramp is expected to facilitate better alignment and control, lower risk and create additional value for the State in the AKLNG Project over the long-term

**BUILDING A
WORLD OF
DIFFERENCE**

30 September 2015

TRANSCANADA PARTICIPATION DECISION

IMPACT ON STATE OF ALASKA

PREPARED FOR THE STATE OF ALASKA



BLACK & VEATCH
Building a world of difference.

PRESENTATION OVERVIEW

- **Background & Description of TC Decision**
- **Overview of TC's current role and State's alternatives related to TC participation**
- **Some key factors for State to consider in TC participation decision**

SB138 FACILITATED ALIGNMENT OF GAS AND CAPACITY OWNERSHIP

UPSTREAM

		EM	BP	CP	SOA	Total
Gas	PBU/PTU	32%	21%	22%	25%	100%
	=	=	=	=	=	=
AKLNG Equity & Capacity	GTP	32%	21%	22%	25%	100%
	Pipeline	32%	21%	22%	25%	100%
	LNG	32%	21%	22%	25%	100%

CURRENTLY HELD BY TC

PRODUCER SHARE OF GAS IS EQUAL TO PRODUCER EQUITY SHARE IN AKLNG

SOA SHARE OF GAS IS NOT EQUAL TO SOA EQUITY SHARE IN AKLNG

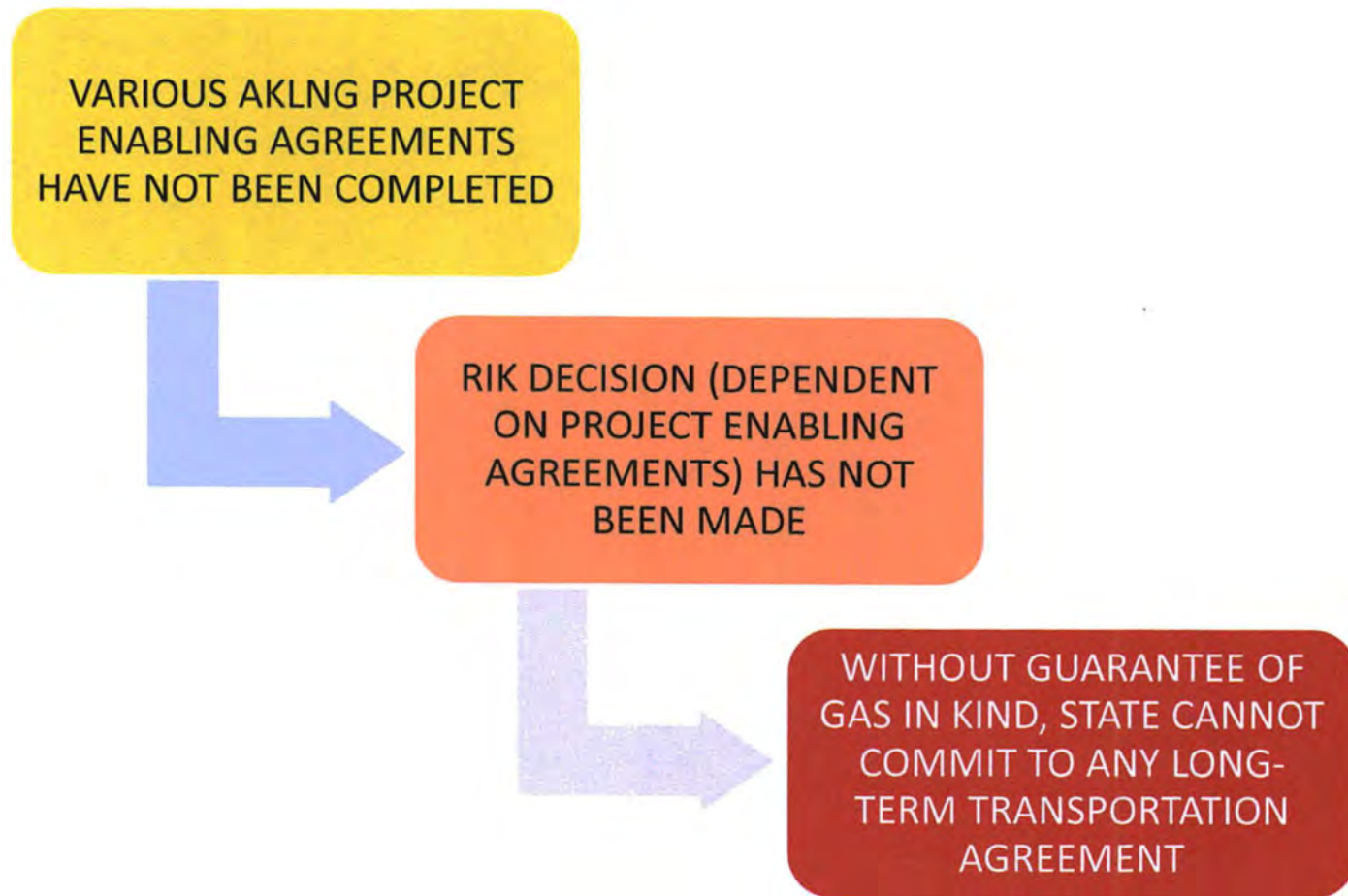
- All ownership shares shown are approximate
- State equity participation is based on production mix from PBU and PTU and the State's royalty share from each field; State equity participation is currently expected to equal 24-25%

TC DECISION NEEDED BY DEC 2015: SHOULD SOA ALIGN ITS GAS WITH ITS EQUITY?

	Gas	GTP	Pipeline	LNG Plant
SOA Aligned Equity (SOA Without TC)	SOA: ~ 25%	SOA : ~25%	SOA: ~25%	SOA: ~25%
FTSA With TC (SOA With TC) ¹	SOA: ~ 25%	TC: ~25%	TC: ~25%	SOA: ~25%

¹The State also has the option to purchase 40% of TC's equity in AKLNG, effectively owning 10% of the midstream (i.e. 40% of 25%). This presentation focuses on the two sideboard options of keeping or terminating TC. The intermediate equity purchase option is presented as an Appendix.

IT WOULD BE PREMATURE & RISKY FOR SOA TO COMMIT TO A LONG TERM FIRM TRANSPORTATION SERVICES AGREEMENT WITH TC BY DECEMBER 2015



Decision is whether to terminate TC relationship in Dec 2015 or delay decision and consider keeping TC in

DIRECT STATE PARTICIPATION IS ADMINISTRATION'S VIEW OF BEST PATH FORWARD

- **The State's direct investment in the AKLNG Project's midstream reflects more favorable value and risk-reward balance for the State compared to TC participation**
 - **Sovereign role** - Desire to have greater control and more direct SOA role in AKLNG
 - Improved project alignment
 - Direct voting rights and representation, including on key issues such as budgets, schedule and pipeline size
 - Ability to directly facilitate midstream expansion
 - **Commercial role** - Reap greater long term cash flows and participation for SOA during project operation by shouldering higher fiscal risk up front
 - Higher operational cash flows of ~\$400 million a year
 - Better overall investment value to State
 - Lower risk of State experiencing negative netbacks without TC – on-going costs paid by State will not need to include TC's return on equity - only financing cost and operating expenses

PRESENTATION OVERVIEW

- **Background & Description of TC Decision**
- **Overview of TC's current role and State's alternatives related to TC participation**
- **Some key factors for State to consider in TC participation decision**

HISTORICAL CONTEXT FOR STATE'S 2014 DECISION TO ENTER INTO PRECEDENT AGREEMENT (PA) WITH TC

- **AGIA framework:**
 - TC was the State's licensee under AGIA
 - AGIA work product could not be transferred to AKLNG until after resolution of AGIA abandonment issues (including cost of the work product)
 - AGIA also contained a treble damages provision
 - It was in this context that the prior Administration negotiated an MOU with TC in 2013, and the AGIA Termination Agreement in 2014, to exit AGIA, transition to AKLNG, and sign the PA with TC
- **Entering into the PA with TC gave the State time during pre-FEED to begin to develop its in-house capabilities in order to fully consider the option of participating directly in midstream at appropriate off-ramps**
 - TC's work on AGIA and APP allowed smooth transition into pre-FEED
- **Entering into the PA with TC for pre-FEED gave the State time to assess its ability to finance its share of investment in AKLNG without TC**
- **There was an expectation that project enabling agreements would be defined before Dec 2015 and enable SOA to evaluate TC role going forward**

THE AGIA TERMINATION AGREEMENT

- **Key provisions of the AGIA Termination Agreement include:**
 - TC and State terminated the AGIA License
 - TC waived any claim of treble damages under AGIA
 - TC agreed to provide State with right to use all AGIA work product of value to the AKLNG project, at no additional up front cost to the State
 - State agreed to complete the AGIA reimbursement process
- **Importantly, under the Agreement the State has a clean off-ramp with TC in 2015**
 - No AGIA treble damages liability
 - No ability of TC to delay project by withholding right to use AGIA work product
 - SOA must pay for TC's AKLNG pre-FEED development costs, with interest (but such costs are ultimately unavoidable)
 - No "back in" right for TC (unlike the FTSA)

STATE'S CURRENT ARRANGEMENT WITH TRANSCANADA



TC Owns the State's ~25% Entitlement to GTP+Pipe
Funds up front midstream cash calls
Technical lead for pipeline during pre-FEED

State to Commit to 20-25 Year Transportation Agreement with TC by Dec 2015 to Pay for Using GTP+Pipe



SOA Ultimately pays TC for all its Costs
(including a cost of capital of ~7%)

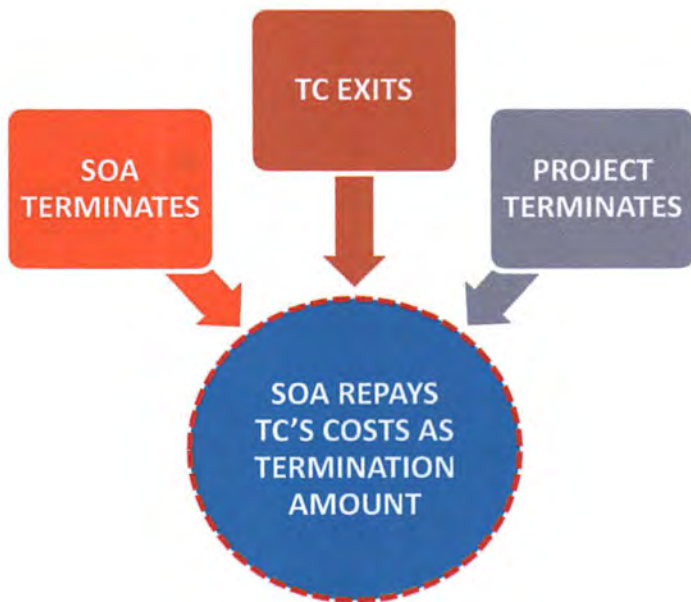
Both SOA and TC have Milestones & Off Ramps:
SOA Responsible for TC Costs, Regardless of Off Ramps



PER PRIOR AGREEMENTS, SOA IS ALWAYS OBLIGATED TO REPAY TC'S COSTS¹



IF PROJECT DOES NOT MOVES FORWARD WITH TC



> Project development risk is borne by SOA

IF PROJECT MOVES FORWARD WITH TC

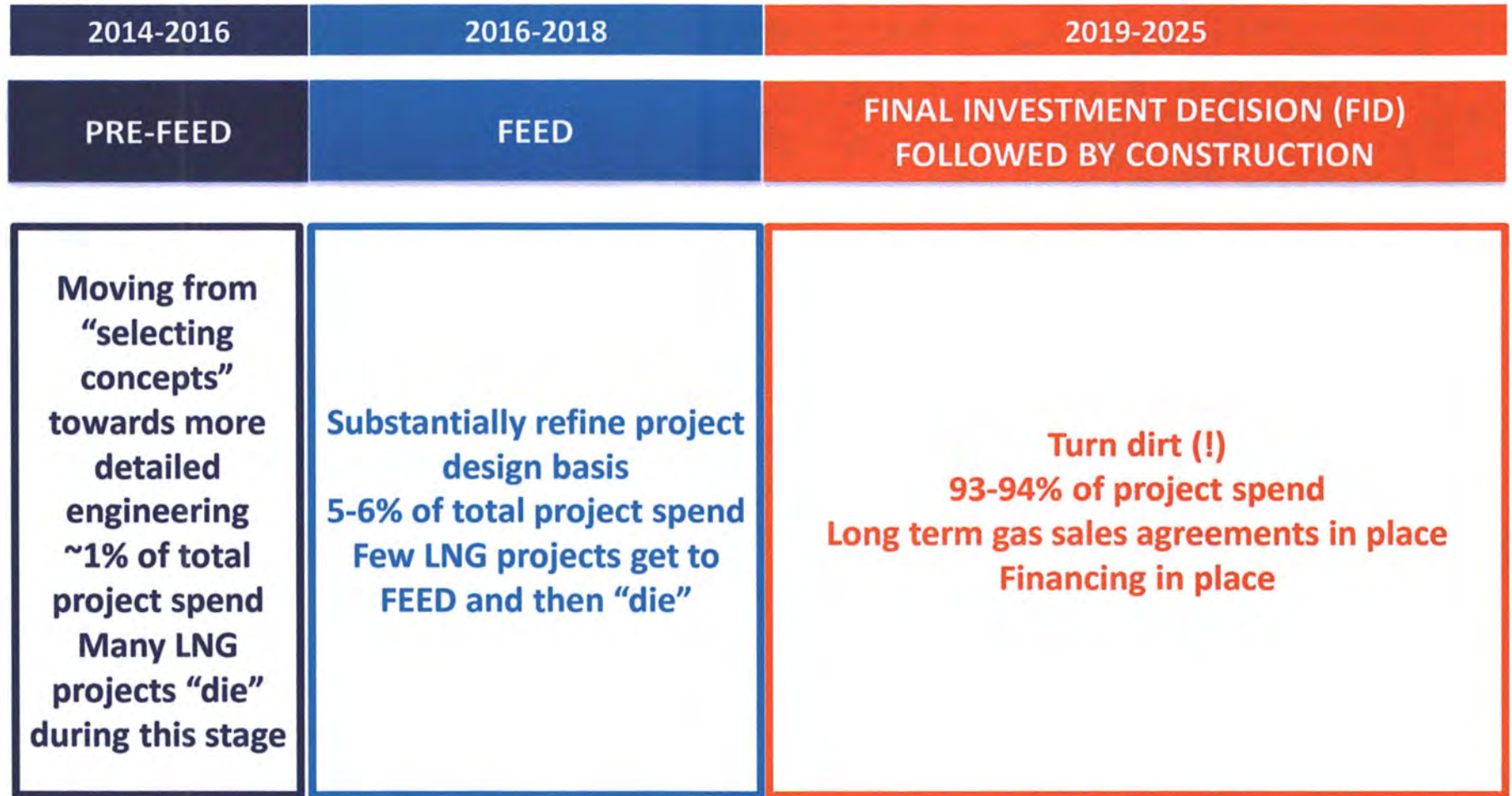


> SOA pays TC tariff regardless of price or volume risks

¹TC costs to be repaid include its share of AKLNG work plan and budget, AFUDC, and internal management fees



STAKES GET HIGHER AS PROJECT PROCEEDS THROUGH STAGE GATES



Less Uncertainty And Increasing Commitments



TIMING OF TC PARTICIPATION DECISION – PROJECT DEVELOPMENT



- **Project development risk is borne by SOA**
- **Unlike the agreements to date, the proposed FTSA contains a “back in” right for TC: no “clean” off ramp if SOA executes it by Dec 2015**
- **If SOA does not execute the proposed FTSA by Dec 2015, TC would have the right but not the obligation to terminate the PA and seek reimbursement of its costs**

TIMING OF TC PARTICIPATION DECISION – PROJECT FID/CONSTRUCTION

Final Investment Decision

CONSTRUCTION

OPERATIONS.....

At Final Investment Decision (FID), before construction (the biggest spend period) commences, the investment needed in the project can be financed and State should be able to directly finance its share of AKLNG costs in a less expensive way than through TC i.e., SOA would get lower tariffs and higher cash flows

=> If the State desires to participate directly in AKLNG midstream, there may not be a strategic reason to wait

\$\$ IMPLICATIONS OF TC PARTICIPATION DECISION AND POTENTIAL OFF RAMPS¹

PROJECT STAGE:	PRE-FEED	FEED	FID	CONSTRUCTION
TIMELINE:	2014-2016	2016-2018		2019-2026
Percent of Spend:	~1%	~5-6%		~93-94%

STATE INVESTMENT

SOA without TC:	~\$130M	~\$625M	~\$13.1B
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SOA with TC:	~\$65M	~\$315M	~\$6.5B
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OFF RAMPS:

<p>Termination Dec. 31, 2015 Pay TC Dev. Costs of ~\$70M² (Incl. TC Internal Costs³) SOA also responsible for remaining GTP and Pipeline Pre-Feed costs from Jan-June 2016 of ~\$38M⁴</p>	<p>Termination Dec. 31, 2018 Pay TC Dev. Costs of ~\$490M (Incl. TC Internal Costs³)</p>
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¹Assumes 25% State equity participation

²\$70M estimate incorporates a \$4M credit for an SOA payment to TC for AGIA reimbursement

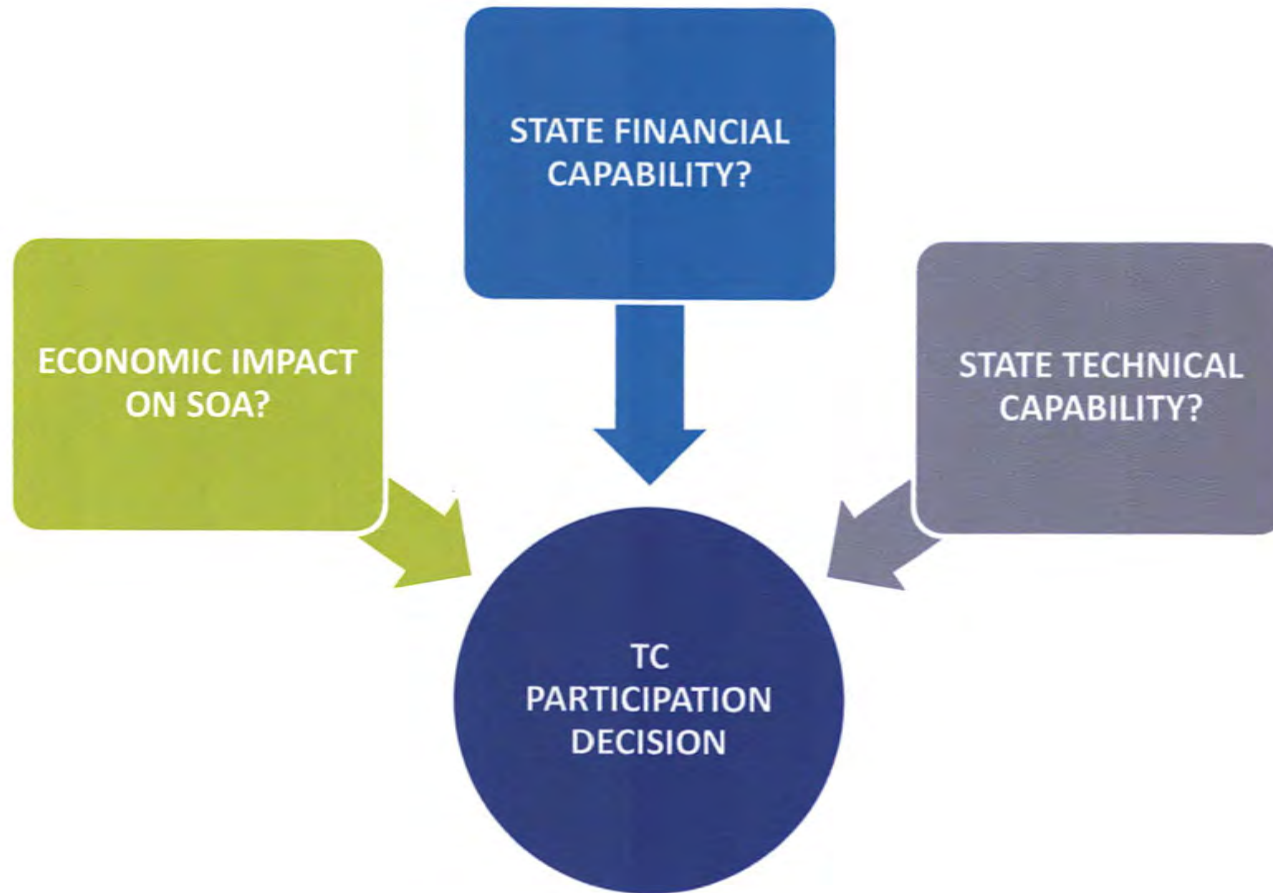
³TC Internal costs include AFUDC and Internal Management Fees

⁴ Provided by AGDC based on current approved WP&B for AKLNG and includes an additional 30% contingency

PRESENTATION OVERVIEW

- **Background & Description of TC Decision**
- **Overview of TC's current role and State's alternatives related to TC participation**
- **Some key factors to consider for State's TC participation decision**

SOME KEY FACTORS TO CONSIDER FOR STATE'S TC PARTICIPATION DECISION



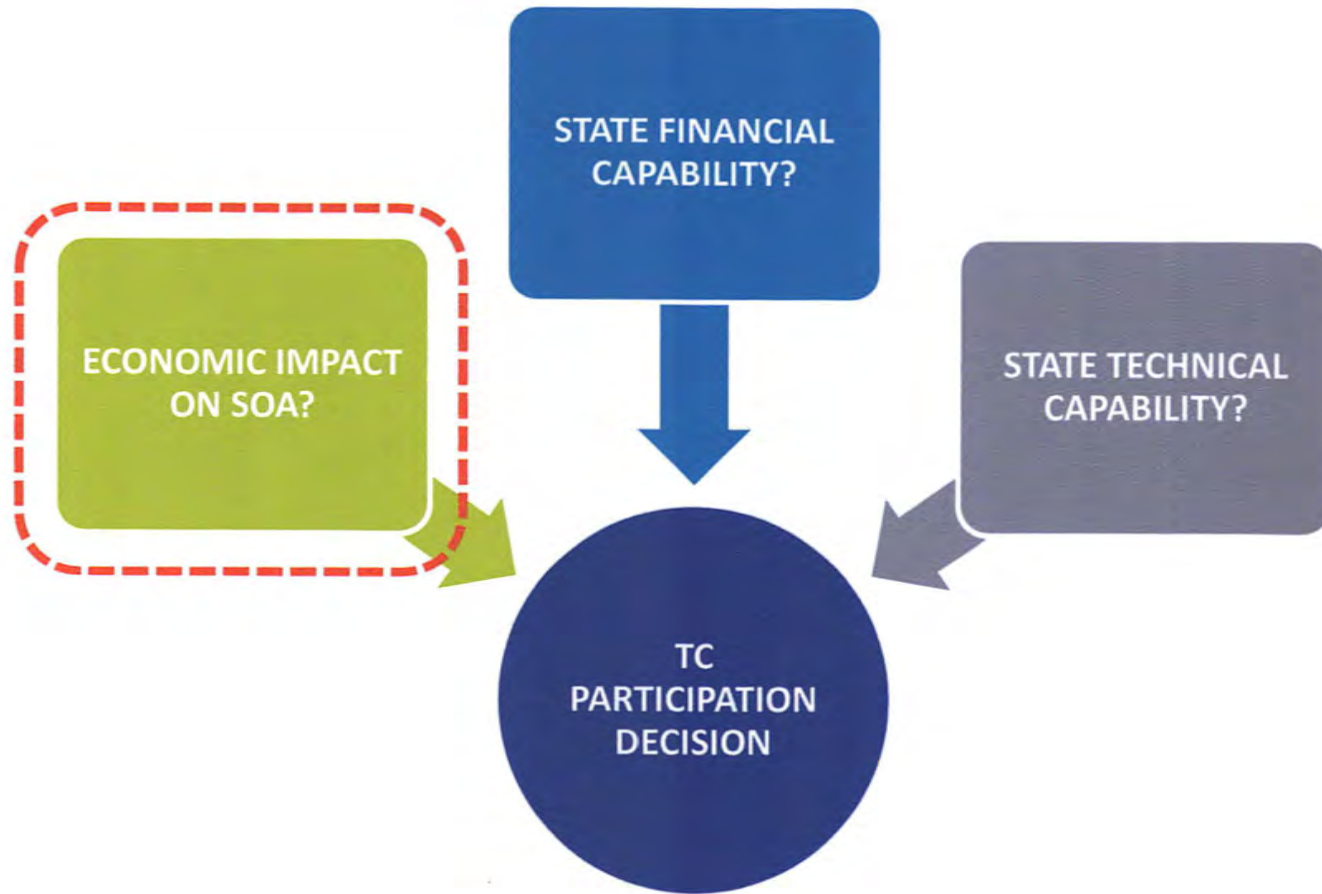
SOME KEY FACTORS TO CONSIDER FOR STATE'S TC PARTICIPATION DECISION

- **What is the economic impact to SOA with and without TC participation?**
 - Near-term cash calls required from State
 - Long-term cash flows to the State
 - Risk exposure for State

- **Does the State have the financial ability to invest directly in the AKLNG midstream segment (i.e., without TC participation)?**
 - SOA financing of TC termination, remaining pre-FEED, FEED and construction costs

- **Does the State have the technical ability to participate directly in the AKLNG midstream segment?**
 - TC is currently the technical lead for pipeline segment; can this role be continued by the State or another project partner?

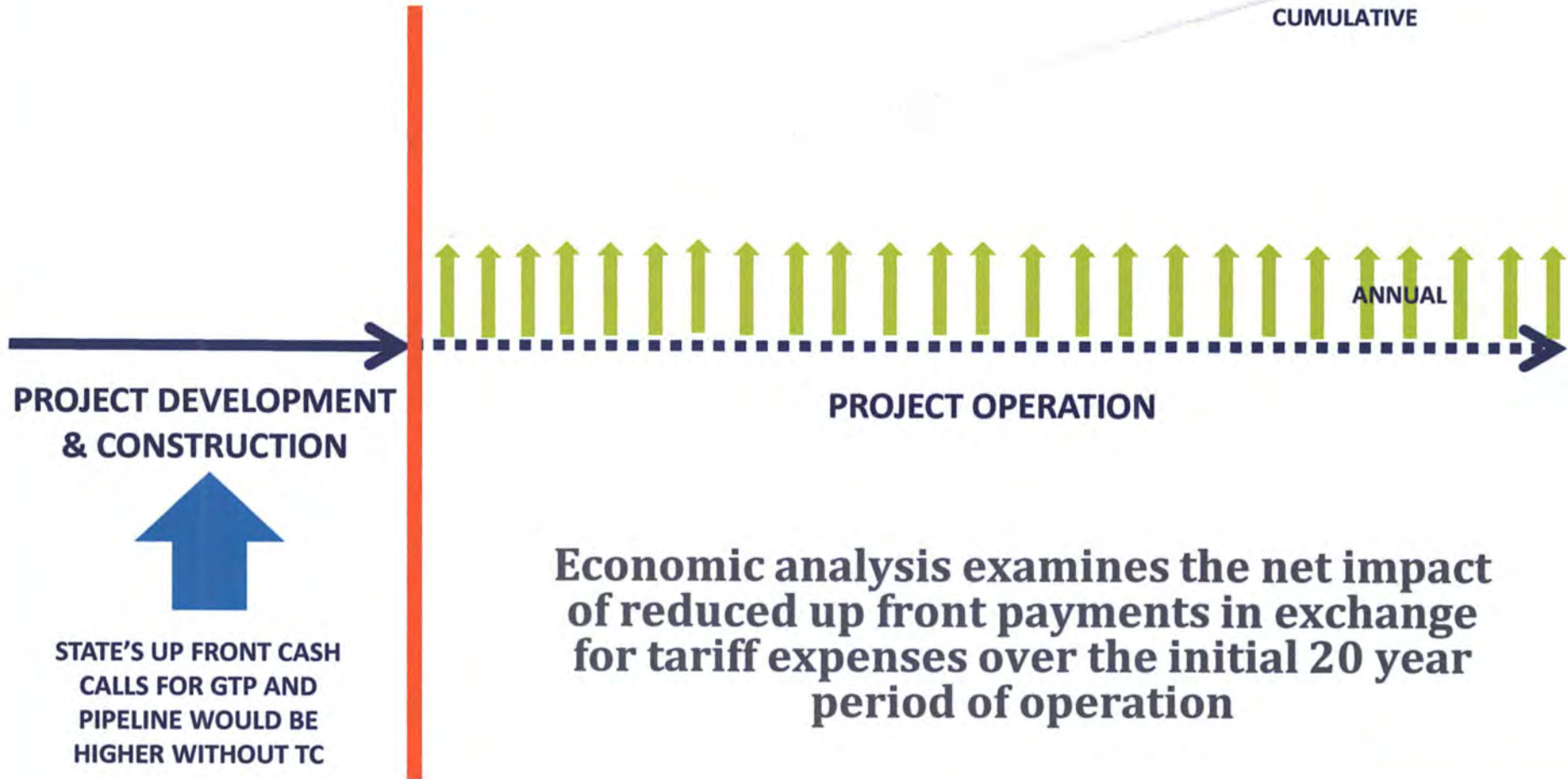
SOME KEY FACTORS TO CONSIDER FOR STATE'S TC PARTICIPATION DECISION



TRANSCANADA IN OR OUT – ECONOMIC IMPACT



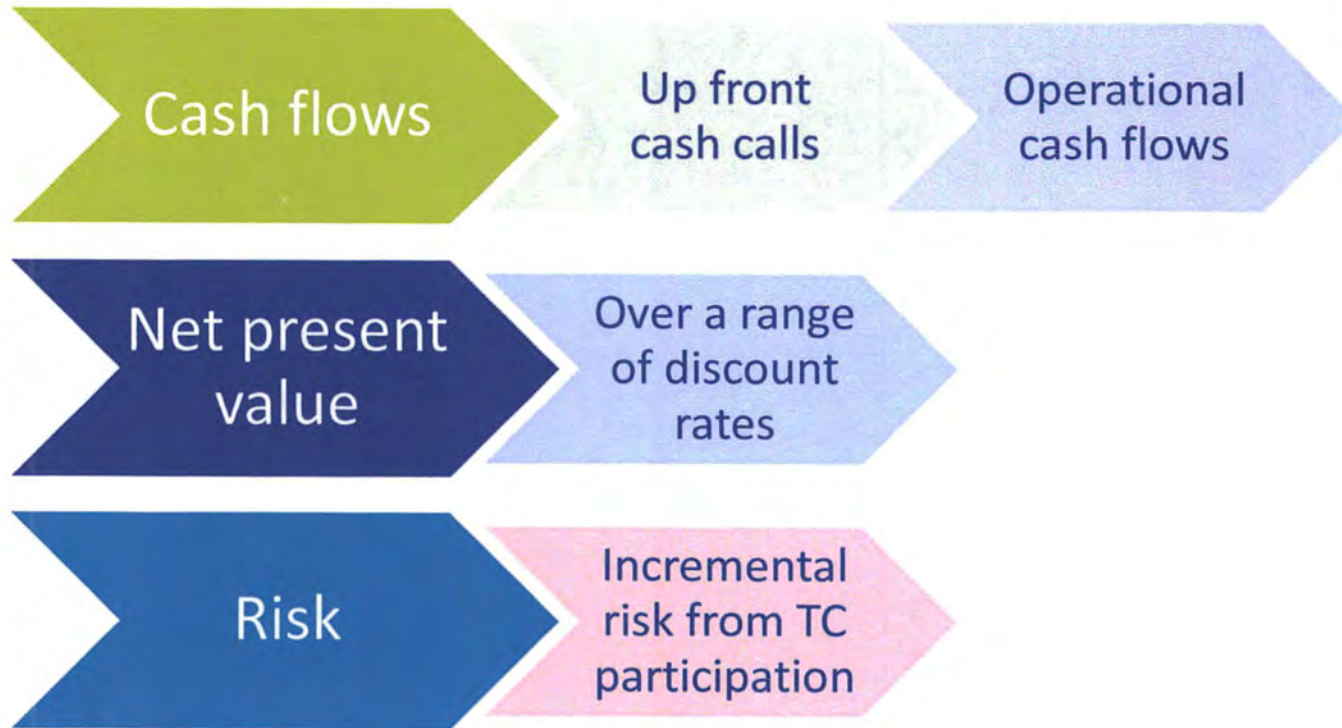
ONCE THE PROJECT IS OPERATIONAL, STATE WOULD ACHIEVE HIGHER ONGOING CASH FLOWS WITHOUT TC



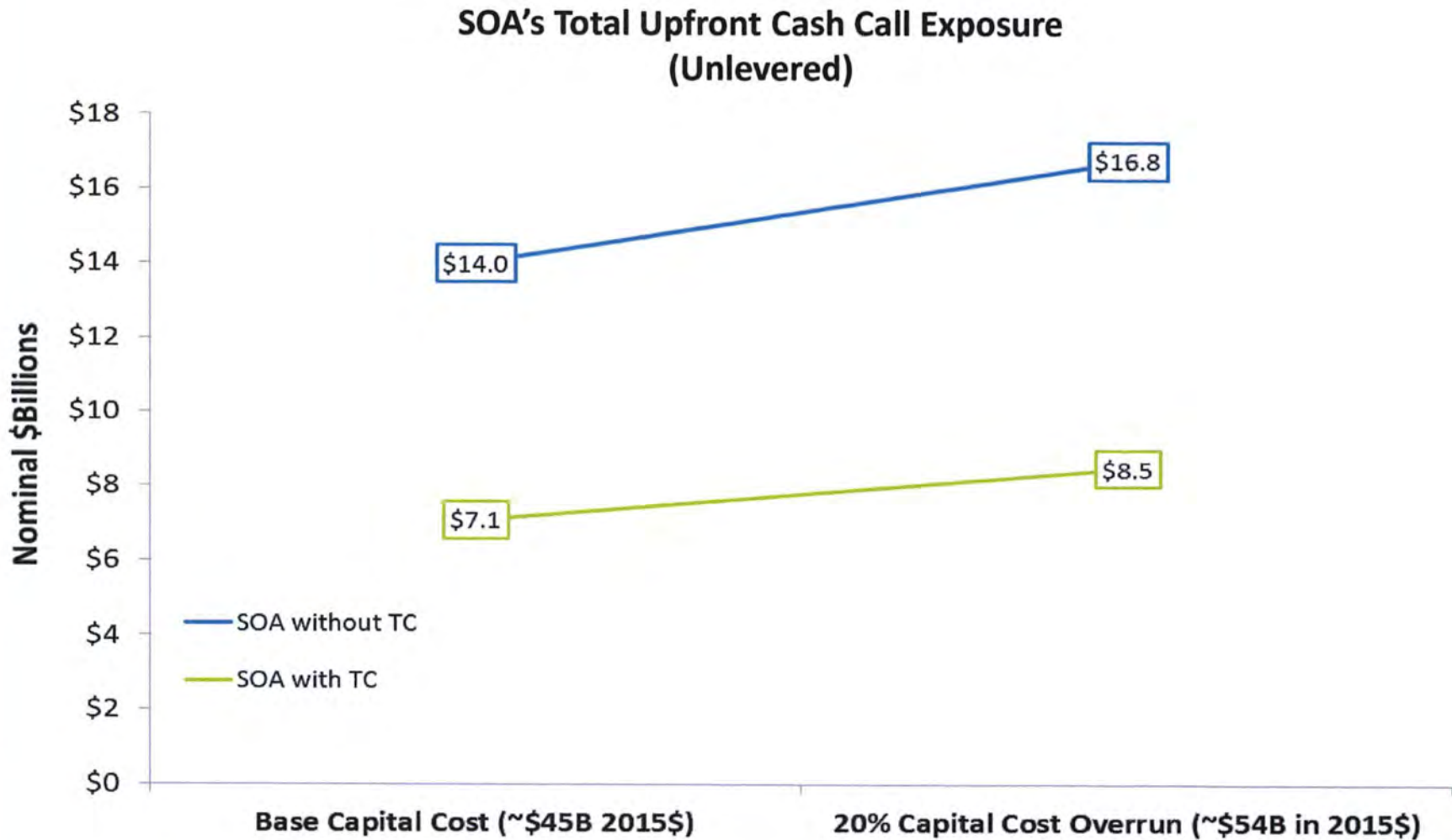
CRITERIA FOR EVALUATING ECONOMIC IMPACT OF TC PARTICIPATION ON SOA



CRITERIA FOR SOA IMPACTS



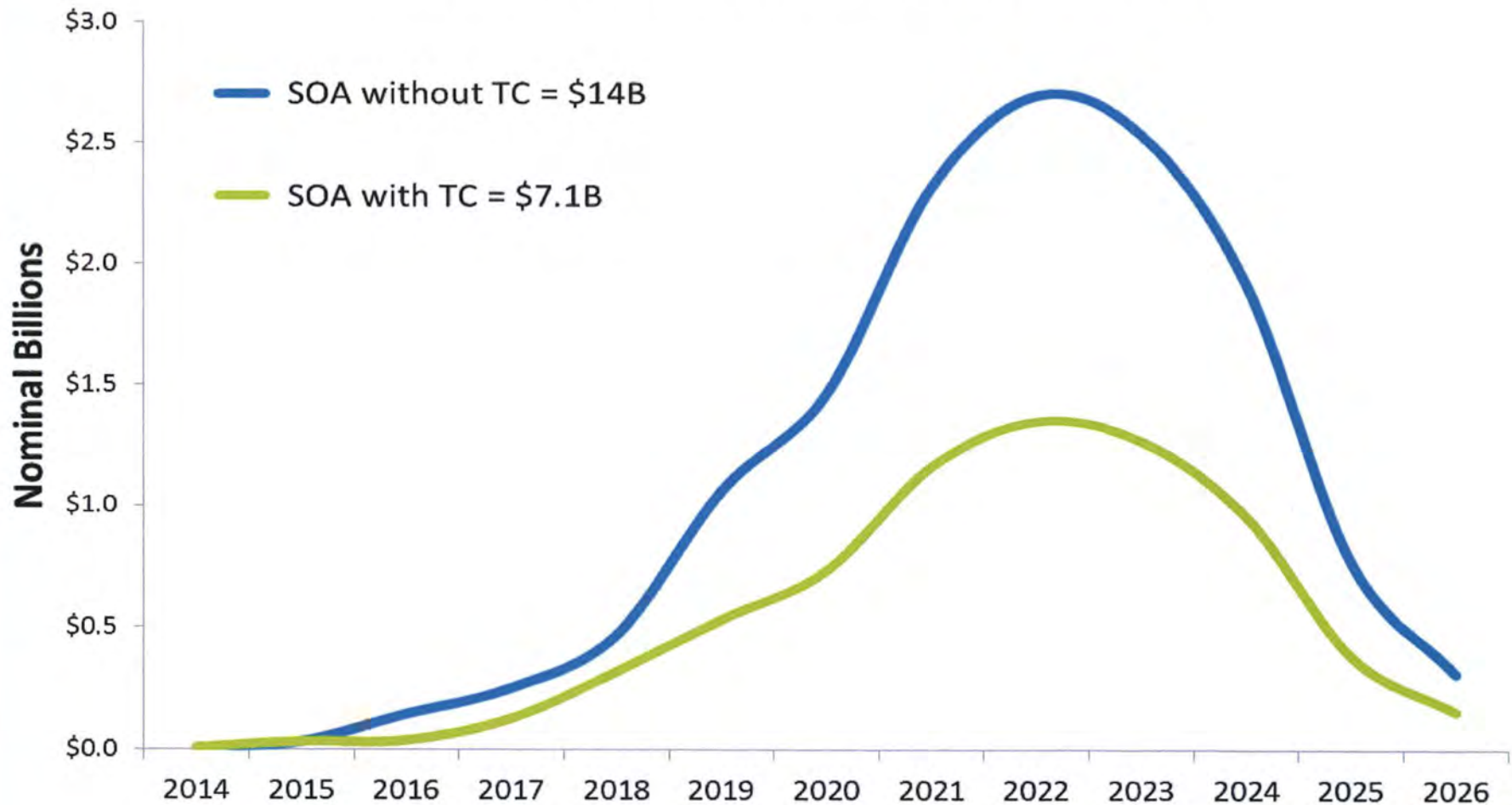
SOA'S TOTAL UPFRONT CASH CALL EXPOSURE IS \$6.9-8.3B HIGHER WITHOUT TC PARTICIPATION



SOA'S ANNUAL UP FRONT CASH CALLS IN THE AKLNG PROJECT ARE EXPECTED TO NEARLY DOUBLE WITHOUT TC



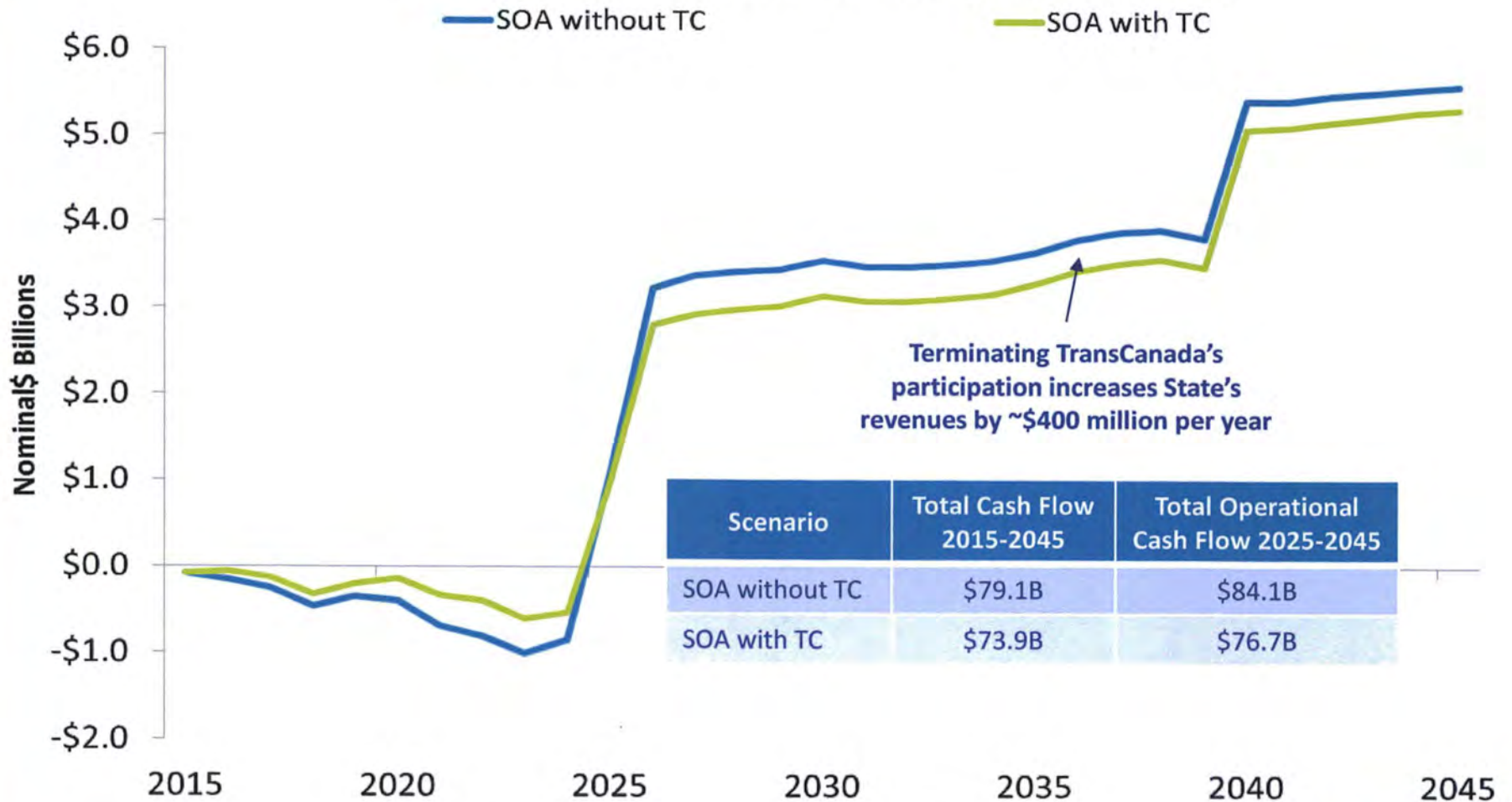
SOA's Annual Upfront Cash Call Exposure (Unlevered)



ONCE OPERATIONAL, SOA IS EXPECTED TO RECEIVE ANNUAL CASH FLOWS OF ~\$400 MILLION HIGHER WITHOUT TC



SOA AKLNG Cash Flow Forecast (Over 20 Years)



NPV INCREASE TO THE STATE WITHOUT TC CAN BE BETWEEN \$0-1.2B OVER 20 YEARS

ECONOMIC IMPACT?



SOA NPV Increase Without TC (\$2015 Billions)



TC INVOLVEMENT AND THE RISK OF NEGATIVE NETBACK FOR THE STATE

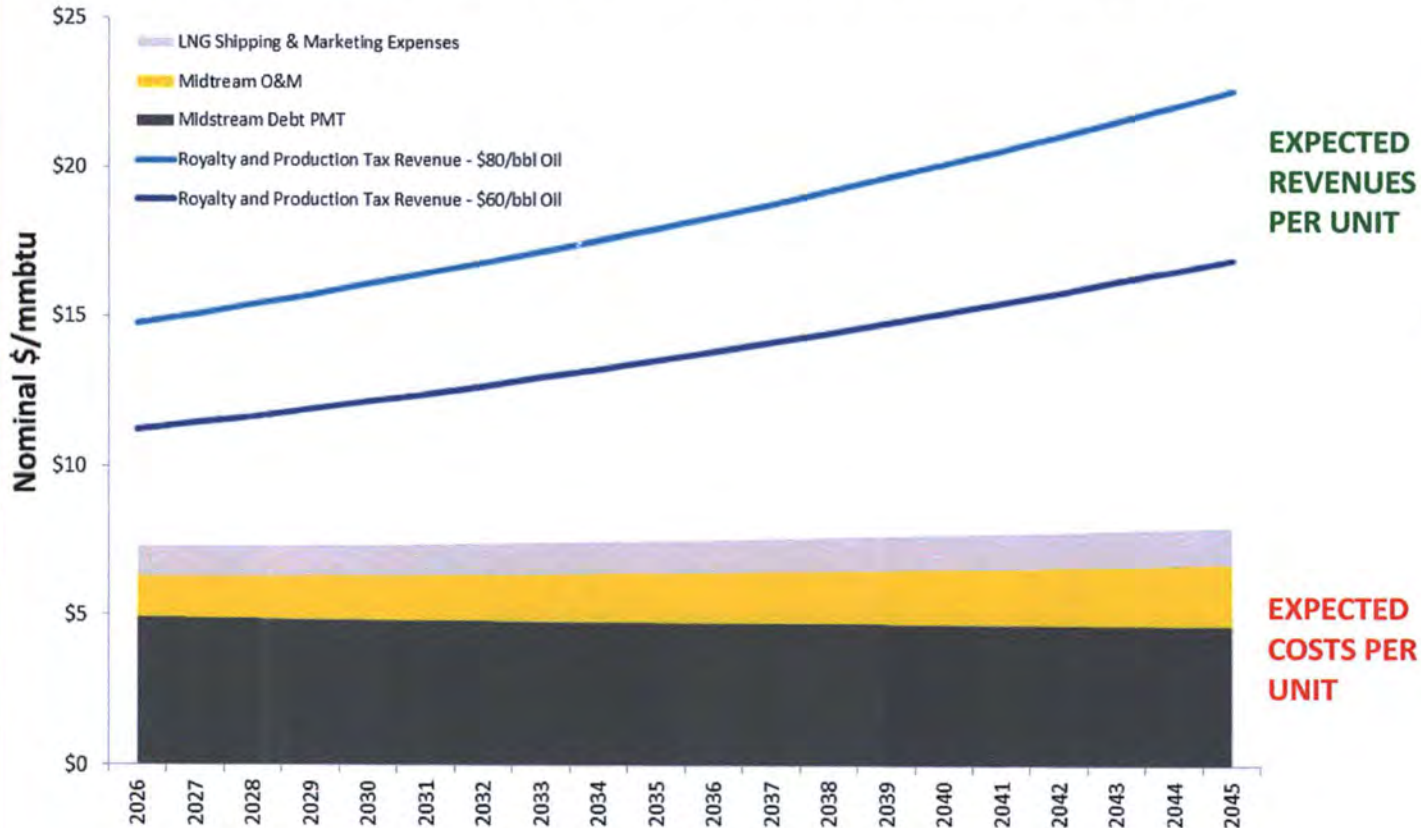


- With an RIK election, the State could be exposed to negative netback if the revenue from its sale of RIK + TAG gas/LNG volumes is insufficient to cover its cost obligations as a shipper
- The State's midstream cost obligations as a shipper are directly affected by midstream ownership (State Midstream Company, TransCanada)
 - Many of the cost obligations would be the same regardless of who owns the midstream assets. These include any upstream expenses, midstream O&M costs, marketing costs, and LNG liquefaction and shipping costs
 - Differences in the obligations arise from factors including how the project is financed, income tax, property tax, and return on equity
- Note: During the sale of RIK and TAG gas and LNG , market pricing mechanisms such as price collars may be available to help manage the State's negative netback risk. The risk management available and associated costs to the State from such mechanisms will be evaluated during the marketing process and are not considered here. This analysis simply looks at the level of negative netback risk for the State that will need to be managed, with and without TC.

STATE'S MIDSTREAM COST OBLIGATIONS WITHOUT TC ARE EXPECTED TO BE ~\$7.30/MMBTU



SOA Expected Revenues & Midstream Costs Per Unit of Gas (Without TC)



- State's midstream cost obligations are expected to be ~\$7.30/MMBtu
- Equivalent to Oil prices in today's dollars at ~\$33/bbl (assuming 13.5% Slope and \$1/MMBtu price adder)
- Oil/LNG prices & gas production are key risks in meeting midstream payment obligations

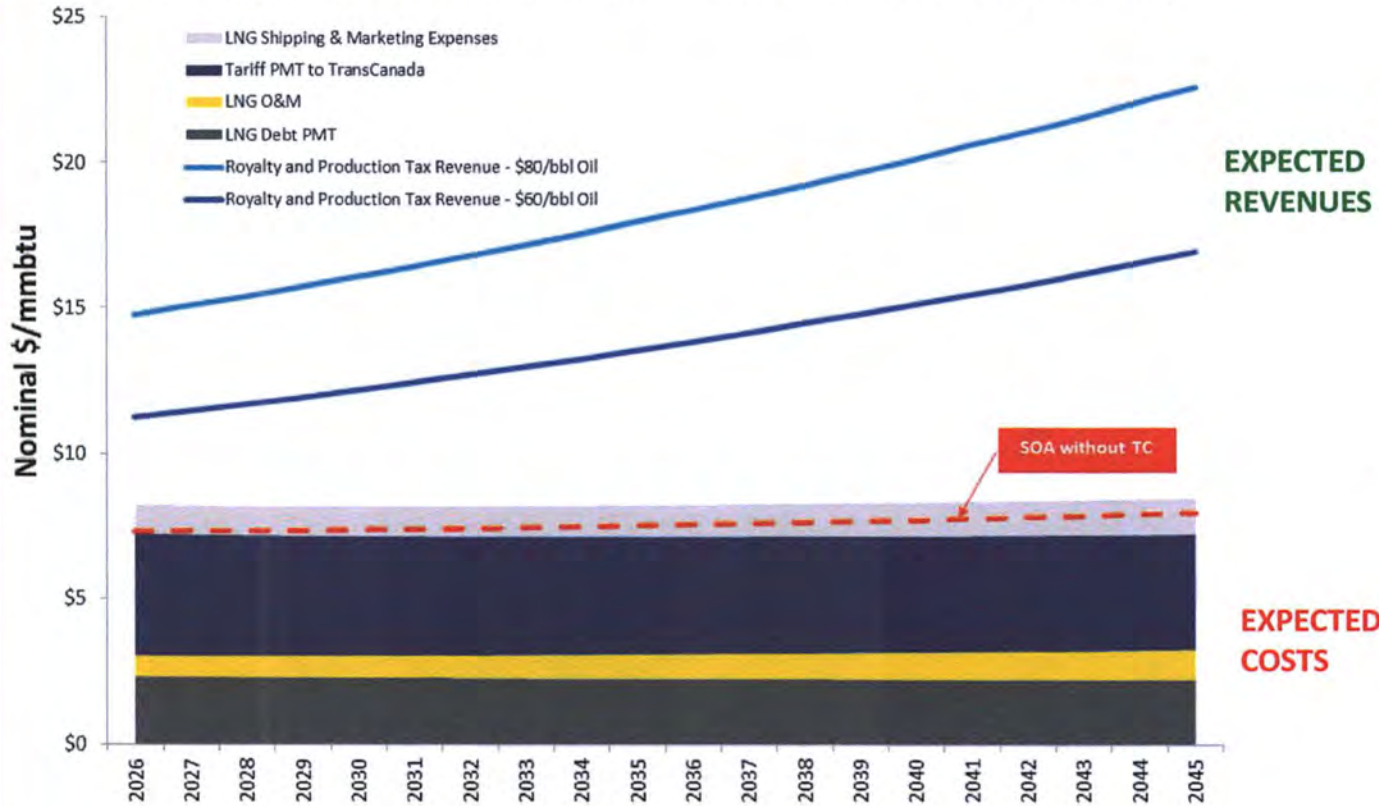
How does TC Involvement in the project impact the State's ability to meet midstream obligations and not have negative netbacks?



WITH TC, THE STATE'S MIDSTREAM COST OBLIGATIONS ARE EXPECTED TO INCREASE TO ~\$8.20/MMBTU



SOA Expected Revenues & Midstream Costs Per Unit of Gas (With TC)



- State's midstream cost obligations are expected to be ~\$8.20/MMBtu with TC compared to ~\$7.30/MMBtu without TC
- Equivalent to Oil prices in today's dollars at ~\$38/bbl compared to ~33/bbl. (assuming 13.5% Slope and \$1/MMBtu price adder)

What is driving the ~\$0.90/MMBtu (in 2026\$) or \$5/bbl (in 2015\$) difference with TC's involvement?

MIDSTREAM COST OBLIGATION DIFFERENCES



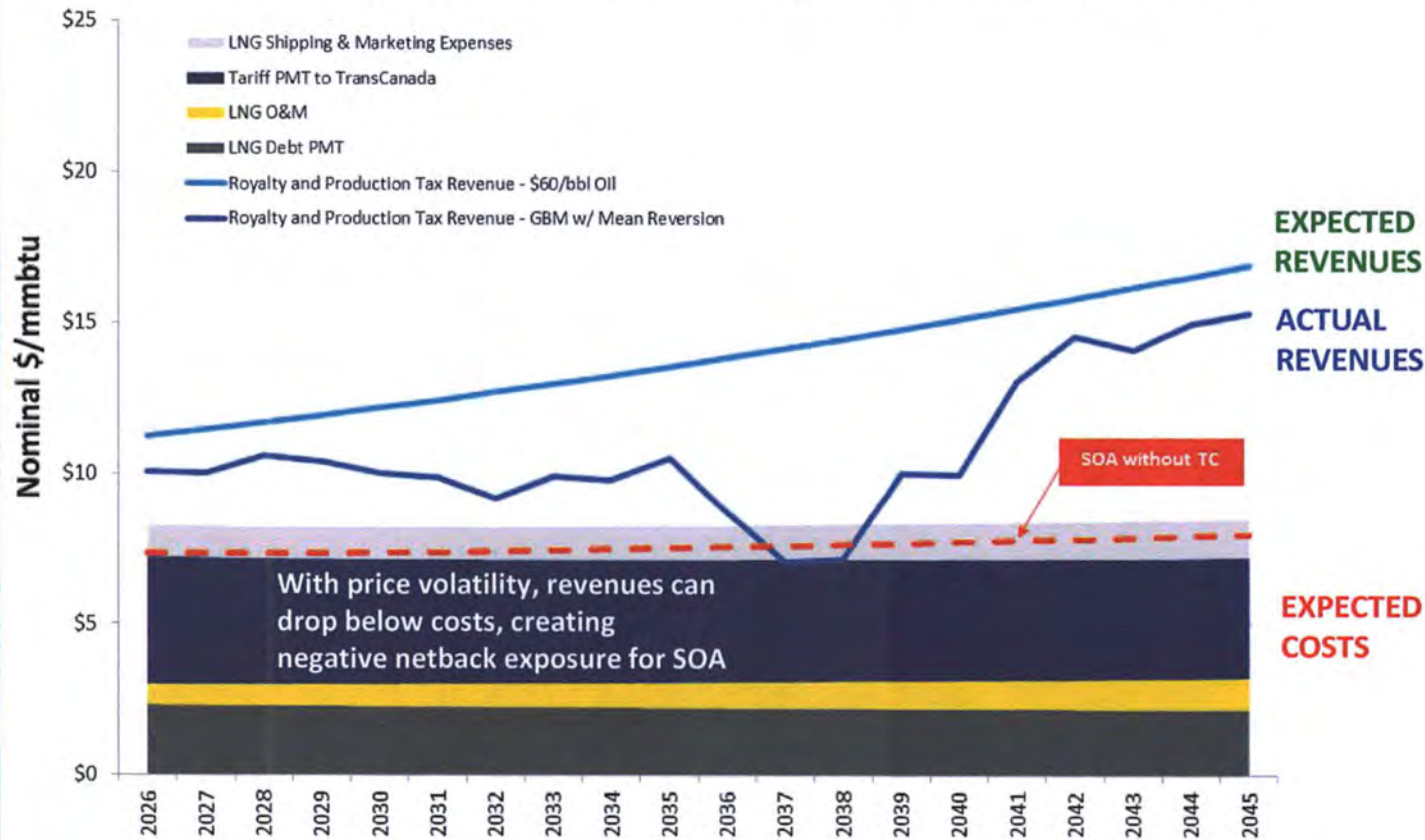
State Midstream Obligation	SOA Without TC	SOA With TC
Midstream O&M	No Difference	
LNG Shipping & Marketing	No Difference	
Weighted Cost of Capital (Return on equity & Cost of debt)	SOA is expected to have lower cost of capital than with TC	SOA pays TC's weighted cost of capital of 7.1% during construction & 6.75% during operations
Property Taxes	SOA Does Not Pay	SOA Tariff includes TC Property Tax Obligation
Income Taxes	SOA Does Not Pay	SOA Tariff includes TC's Payment of Income Taxes

Additional cost elements make SOA's midstream obligations higher with TC

STATE'S NEGATIVE NETBACK RISK INCREASES WITH TC: EXAMPLE

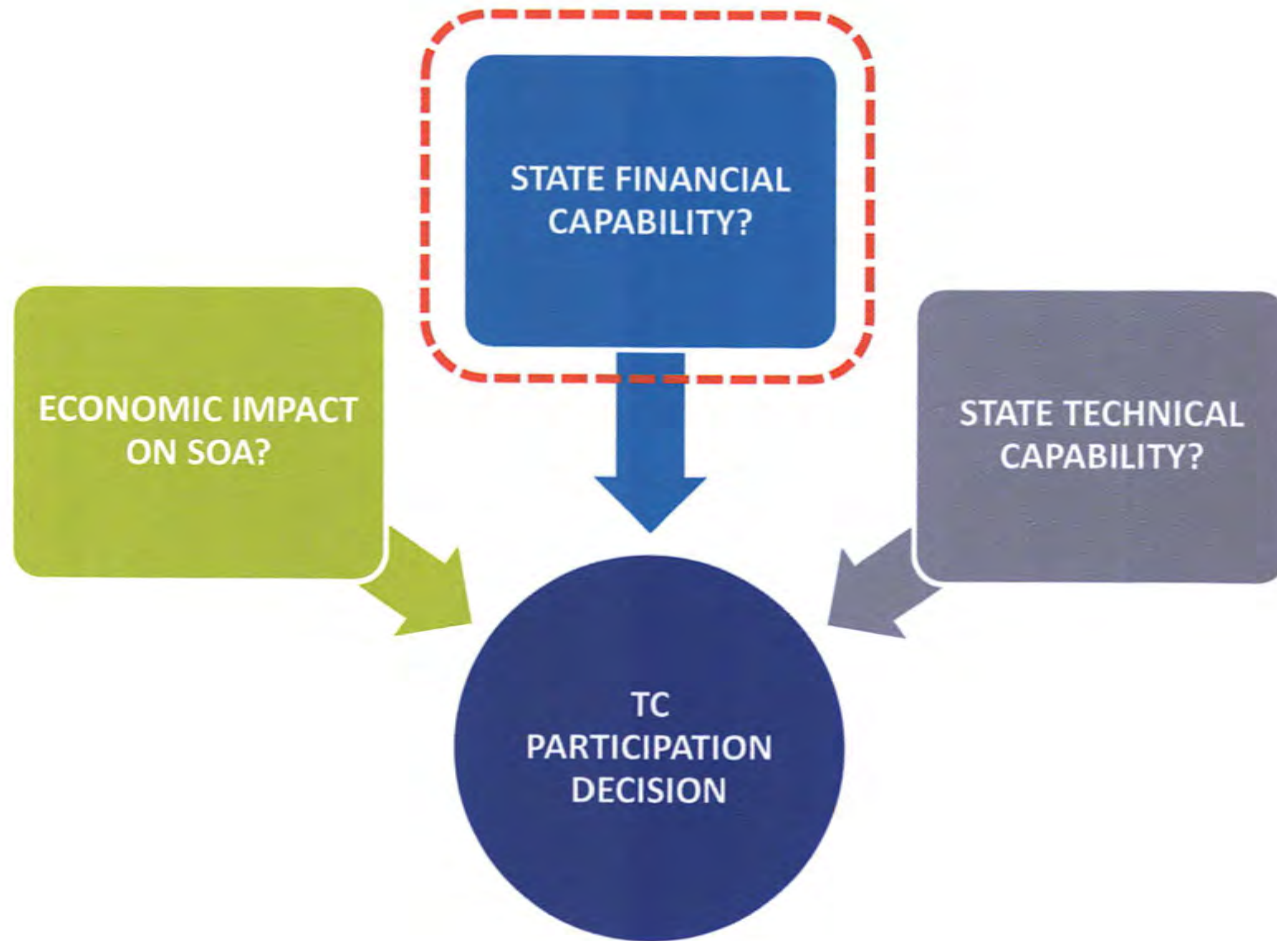


SOA Expected Revenues & Midstream Costs Per Unit of Gas (With TC)



- With TC, the cost level that the State's revenues need to cover are about \$1/MMBtu higher than without TC
- This is expected to increase the likelihood and magnitude of negative netback—i.e., potential draws on the General Fund - that the State could experience during low price events

SOME KEY FACTORS TO CONSIDER FOR STATE'S TC PARTICIPATION DECISION



WHAT ARE THE FINANCIAL IMPLICATIONS TO SOA OF TC PARTICIPATION?



- **Two financial costs of terminating TC relationship:**

- Immediate transition costs of terminating TC involvement
- Subsequent direct investment in AKLNG midstream

- **Two financial benefits of terminating TC relationship:**

- Immediate relief from funding TC administrative costs¹
- Eliminate accrual of TC financing costs (~7% interest)

¹ There may be corresponding increases to AGDC administrative costs associated with the Midstream.

SOA'S UPFRONT CASH CALLS WITHOUT TC INCREASE BY ~\$108M FOR PRE-FEED AND ~\$310M FOR FEED



Nominal \$M	Midstream ¹
TC Termination Amount	~\$70 ²
AGDC Pre-FEED	~\$38 ³
FEED	~\$310
Construction ⁴	~\$6,500 - \$7,800

} Pre-FEED

¹ Midstream includes PBU & PTU Transmission Lines, Gas Treatment Plant, and Mainline
² TC Termination Amount includes TC Internal Costs (AFUDC + Management Fees) and a credit of ~\$4M for SOA payment to TC for AGIA reimbursement
³ Provided by AGDC based on current approved WP&B for AKLNG and includes an additional 30% contingency
⁴ Range of costs is based on current estimates to 20% cost overrun

WITHOUT TC, SOA'S TOTAL UPFRONT CASH CALLS WOULD BE ~\$173M FOR PRE-FEED & ~\$625M FOR FEED



Nominal \$M	Midstream ¹	LNG	Total	
TC Termination Amount	~\$70 ²	-	~\$70	} Pre-FEED
AGDC Pre-FEED	~\$38 ³	~\$65	~\$103	
FEED	~\$310	~\$315	~\$625	
Construction ⁴	~\$6,500 - \$7,800	~\$6,500 - \$7,900	~\$13,100 - \$15,700	

¹ Midstream includes PBU & PTU Transmission Lines, Gas Treatment Plant, and Mainline

² TC Termination Amount includes TC Internal Costs (AFUDC + Management Fees) and a credit of ~\$4M for SOA payment to TC for AGIA reimbursement

³ Provided by AGDC based on current approved WP&B for AKLNG and includes an additional 30% contingency

⁴ Range of costs is based on current estimates to 20% cost overrun

SOA'S COST OF CAPITAL IS EXPECTED TO BE LOWER THAN TC'S

DOR analyzes the TransCanada agreement as a non-GO State debt borrowing that may be called on demand by TransCanada with an interest cost significantly higher than the State could achieve through a market-rate State debt borrowing

- TC's "deemed" weighted cost of capital per contract is
 - Development & Construction:
 - 70/30 Debt/equity ratio¹
 - 4.05% Cost of Debt/ 11.05% Return on Equity²
 - Weighted average cost of capital = **6.15%**²
 - Operation:
 - 75/25 Debt/equity ratio
 - 4.05% Cost of Debt/ 11.05% Return on Equity²
 - Weighted average cost of capital = **5.80%**²
- SOA's cost of financing its midstream share directly is expected to be lower than through TC

¹Ratio applies through the second anniversary of the in-service date

²TC deemed cost of capital changes with variations in the yield of 30-year Treasuries. The cost of capital figures shown are based on the Treasuries yield as of September 25, 2015

STATE'S ABILITY TO FUND TERMINATION AMOUNT FOR TC



- **The costs for the TC termination amount through pre-FEED to date will need to be funded through legislative appropriation**
- **Legislature has a number of viable readily implemented funding options available to it for the TransCanada reimbursement of Developments Costs.**
 - The Legislature could appropriate funds from the CBRF or authorize a short or intermediate term borrowing with non-GO State debt (moral obligation or certificates of participation)
 - The Legislature could also do a combination of the two, with initial funding from the CBRF to be reimbursed by a non-GO State debt issuance or proceeds from financing provided by future equity partners and/or LNG buyers
 - Note that given the relatively small size of the TransCanada reimbursement, the State could consider both bank financing and municipal market bonding
 - First Southwest believes that a State borrowing could be feasible and would result in materially lower interest costs to the State than under the TransCanada agreement
 - Interest payments on any State borrowing would be funded by annual appropriation, with the anticipation that principal repayment would be rolled into a future long term financing if the Project reaches FID

STATE'S ABILITY TO FINANCE ITS SHARE OF AKLNG COSTS – PRE-FEED



- **AGDC's remaining midstream Pre-FEED JVA costs will need to be funded through legislative appropriations**
- **The funding could be done in the same way as the current AGDC Downstream Pre-FEED JVA costs are funded**
- **Alternatively, the same funding program identified for the TransCanada reimbursement of Development Costs could be utilized**
 - The Legislature could appropriate funds from the CBRF or authorize a short or intermediate term borrowing with non-GO State debt or a combination of the two

STATE'S ABILITY TO FINANCE ITS SHARE OF AKLNG COSTS – FEED



- The AGDC Downstream and Midstream FEED costs will need to be funded through legislative appropriations
- It is anticipated that the SOA total share of FEED amount could approach \$625 million, an increase of \$310 million without TC
- For the AGDC Downstream and Midstream FEED costs, the Legislature would have the same options available to fund such costs as outlined in the funding program identified for the TransCanada reimbursement
- In addition, given the additional time available before the FEED funding decision is ripe, the Legislature could consider proposing a GO debt offering which would require a voter referendum approval
 - The State would have the option to issue annual tranches of debt to meet the annual appropriation requirements or a single tranche to fund the total FEED period costs.
 - Interest payments could be funded by annual appropriation, with the anticipation that principal repayment would be rolled in a future long term financing.

STATE'S ABILITY TO FINANCE ITS SHARE OF AKLNG COSTS – FEED (CONT.)



- The state may also be able to obtain financing from future equity investors and/or LNG buyers
- Under the existing agreements with TC, the State has to support its obligations under the PA and FTSA with the full faith and credit of the State of Alaska or provide other credit support acceptable to TC
 - The State is expected to obtain less expensive borrowing on its own in the debt market
- Given that the State's financial consultants, First Southwest and Lazard, advise that the State would have the ability to access the bank debt and municipal bond market for funds to replace the TransCanada debt, DOR is comfortable the State can readily fund AGDC's share of costs through FEED at a lower overall cost to the State

STATE'S ABILITY TO FINANCE ITS SHARE OF AKLNG COSTS – CONSTRUCTION

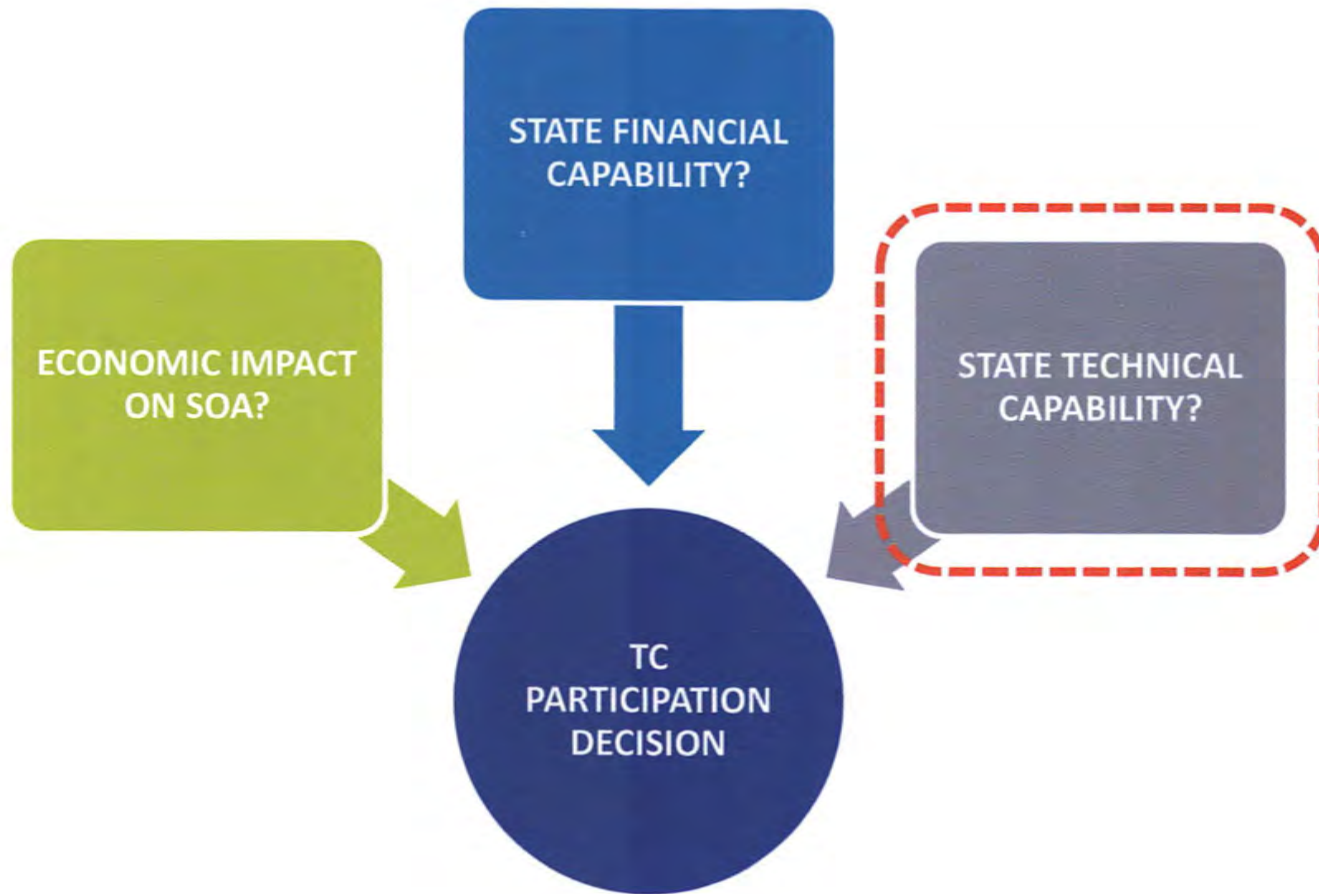


- The AGDC Downstream and Midstream post-FID construction costs will need to be funded through legislative appropriations
- It is anticipated that this amount could approach \$13.1-15.7 billion
- The Legislature would have the same options as for FEED costs to fund construction costs
- Given the magnitude of the expenditures, the borrowing plan would look more to the municipal bond market than to bank borrowing
- It is anticipated that at the time of placement of the Project into operation, the State would re-finance outstanding debt with long term municipal bond market borrowing or a Permanent Fund investment or a combination of both
- SOA/AGDC would not have the option to access project financing under our understanding of the current Constitution's limitations against pledging State royalties and tax revenues.
 - A Constitutional Amendment would be required specifically to allow a pledge of RIK/TAG revenues to enable an SOA/AGDC borrowing for the AKLNG Project

PROVIDED TO BLACK & VEATCH BY DEPARTMENT OF REVENUE



SOME KEY FACTORS TO CONSIDER FOR STATE'S TC PARTICIPATION DECISION



CAN THE STATE PROCEED WITHOUT TC – TECHNICAL ABILITY?



- **TC is highly experienced in northern pipelines and leads the pipeline technical work for AKLNG**
- **TC in its current role performs or has performed several functions including the following:**
 - Holds State of Alaska's midstream equity in AKLNG as signatory to the JVA
 - Is SOA's midstream participant in JVA Governance and decision making
 - Provided the majority of the pipeline SMEs that were seconded to the JVA PMT
 - Provided technical advice to the State of Alaska on midstream design, especially the 48 inch pipe position
 - Helpful assistance and input on negotiation of key agreements like Expansion
 - Coordinated FERC NEPA Process

MIDSTREAM CAPABILITIES WITHIN AKLNG



- **The end of the pre-FEED stage in the AKLNG Project's development is a natural transition point in activities**
- **Project delay is not expected if TC agreement is terminated in December 2015, as the pre-FEED work products near completion**
- **The AKLNG Project producer partners have worldwide experience and resources to be able to step into the pipeline technical lead role played by TC**
 - The #2 on the Pipeline Team is an EM employee with significant experience
 - The GTP, which is part of Midstream is already being managed by an EM secondee
 - Exxon designed and built TAPS and thus has Alaska-relevant experience on midstream
- **AKLNG may be able to hire pipeline employees currently seconded to the project by TC**

AGDC CAPABILITIES IN MIDSTREAM



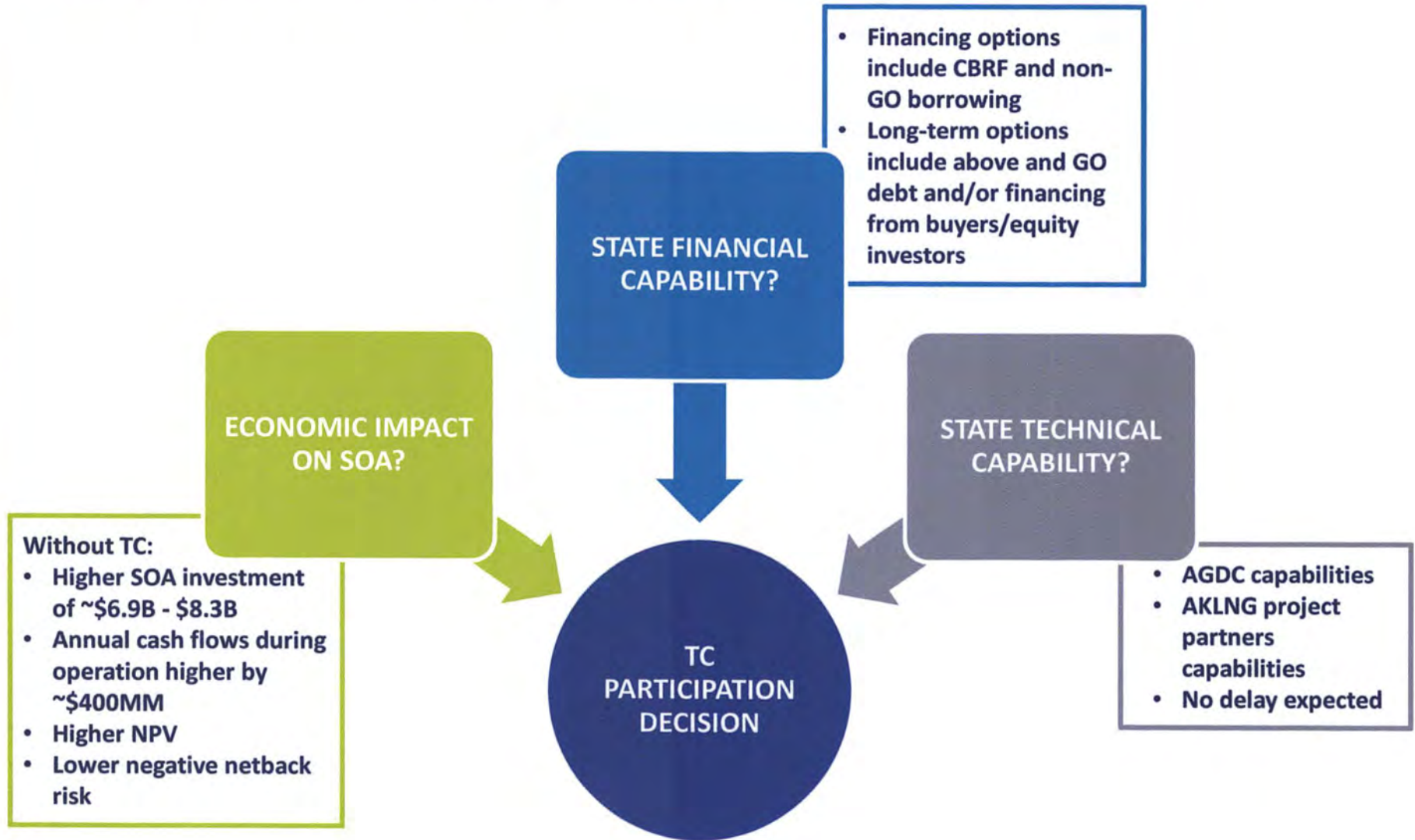
- **AGDC has completed Pre-FEED and FEED work on ASAP**
- **Practical knowledge/experience with the proposed RoW on ASAP – already have all the State lands RoW granted to them and expect the Federal portion to be granted as soon as the NEPA process is completed in mid 2016**
- **Experienced in the NEPA process although ASAP is under USACE and not FERC – AGDC has filed an EIS**
- **AGDC’s ERL person has taken over the permitting from the TC person who had led that effort**
- **Challenges/gaps –**
 - Limited current experience on the GTP - AGDC is expected to add staff/contractors to close this gap
 - Limited direct experience with 48” pipelines in northern conditions

OTHER CAPABILITIES – COMMERCIAL



- **Both the State Gas Team and AGDC have strong midstream regulatory and commercial skills to participate in regulatory processes as well as in commercial negotiations with Producers**
- **Negotiations with Producers on project expansion and third party access issues are being led by the State Gas Team and AGDC using legal resources and SMEs where appropriate for support**

SUMMARY OF 3 KEY FACTORS TO CONSIDER FOR STATE'S TC PARTICIPATION DECISION



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APPENDICES



HIGH LEVEL ASSUMPTIONS FOR ANALYSIS

Description	Assumption
Project In-Service	2025/2026
Analysis Period	First 20 years of operation
Pipeline Inlet (Tbtu/d)	3.2
Royalty	In Kind
Production Taxes (13% Gross)	Tax as Gas
AKLNG Project Capital Costs (2015\$)	~\$45B
SOA Equity	~24-25%
Long Term Flat Real Oil Prices (2015\$)	\$80/bbl
LNG Price (\$/MMBtu)	13.5%* Oil Price + \$1
Midstream CapEx Escalation (Short-term)	3.0%
Long Term Escalation	2.5%
Capital Structure	70% Debt/ 30% Equity
Cost of Debt	5%
ROE	12%

LIST OF ACRONYMS

Acronym	Definition	Acronym	Definition
AFUDC	Additional Funds Used During Construction	MMBTU	Million British Thermal Units
AGDC	Alaska Gasline Development Corporation	MOU	Memorandum of Understanding
AGIA	Alaska Gasline Inducement Act	NEPA	National Environmental Policy Act
AKLNG	Alaska Liquefied Natural Gas Project	non-GO	non-General Obligation
APP	Alaska Pipeline Project	NPV	Net Present Value
ASAP	Alaska Stand Alone Pipeline	O&M	Operations and Maintenance
BP	(Formerly British Petroleum)	PA	Precedent Agreement
CBRF	Constitutional Budget Reserve Fund	PBU	Prudhoe Bay Unit
CP	Conoco Phillips	PMT	Payment
DNR	Department of Natural Resources	pre-FEED	Pre-Front End Engineering & Design
DOR	Department of Revenue	PTU	Point Thomson Unit
EIS	Environmental Impact Statement	RIK	Royalty in Kind
EM	ExxonMobil	ROE	Return on Equity
ERL	Environmental, Regulatory & Land	RoW	Right of Way
FEED	Front End Engineering & Design	SME	Subject Matter Expert
FERC	Federal Energy Regulatory Commission	SOA	State of Alaska
FID	Final Investment Decision	TAG	Tax as Gas
FTSA	Firm Transportation Sales Agreement	TAPS	Trans-Alaska Pipeline System
GBM	Geometric Brownian Motion	TC	TransCanada
GTP	Gas Treatment Plant	USACE	United States Army Corps of Engineers
JVA	Joint Venture Agreement	WACC	Weighted Average Cost of Capital
LNG	Liquefied Natural Gas	WP&B	Work Plan and Budget

TC WITH 40% EQUITY OPTION

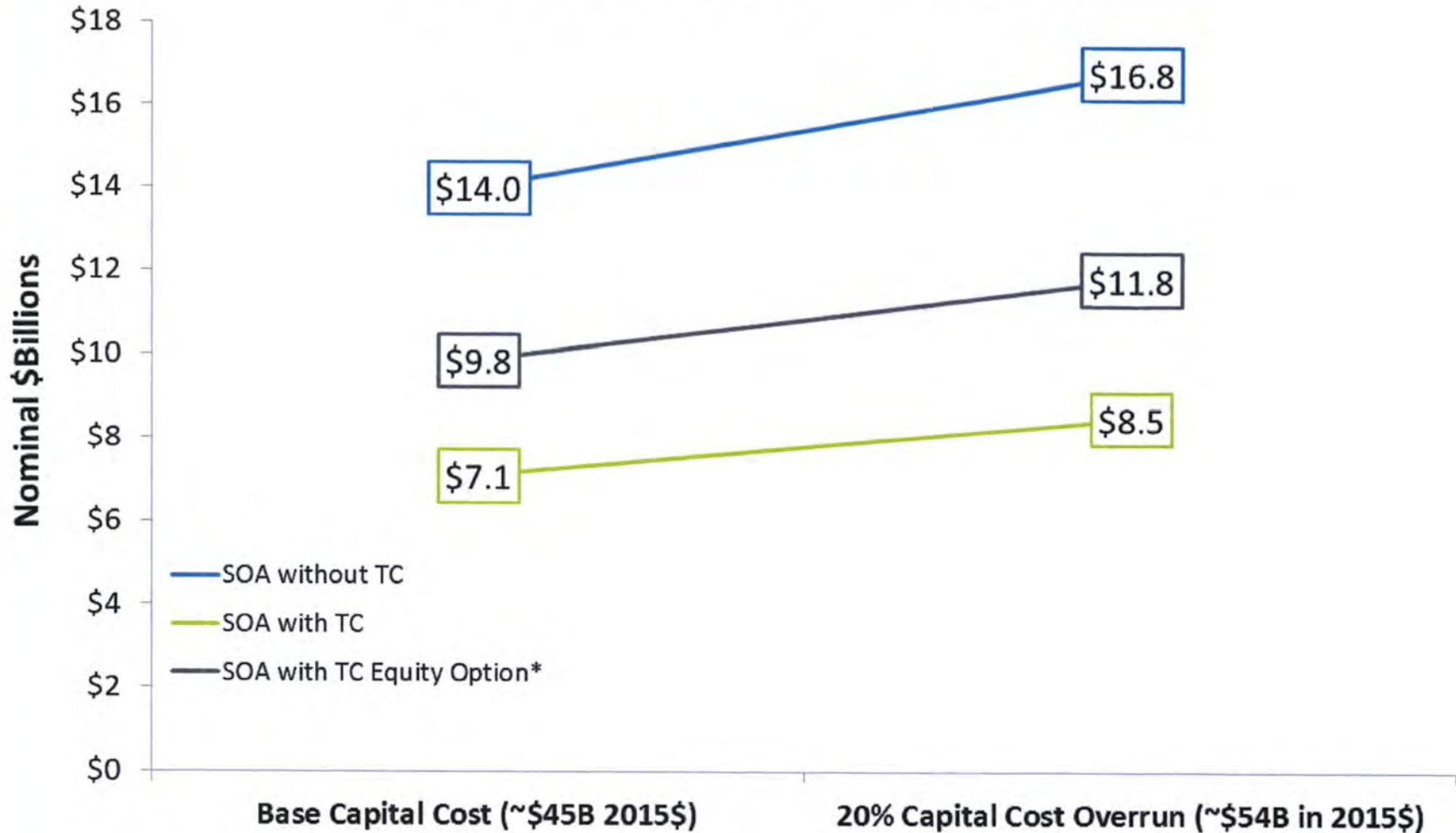
THE OPTION TO BUY BACK 40% EQUITY

- Current MOU/PA with TransCanada also gives the State an option to buy back 40% of its original 25% share in the pipeline and GTP from TC
- Under the currently contemplated structure, the 40% interest would equate to ~10% equity (i.e., 40% of 25%) in GTP and Pipeline project
- Option must be exercised by December 2015

	Gas	GTP	Pipeline	LNG Plant
SOA With TC 40% Equity Option	SOA: ~ 25%	TC: ~15%	TC: ~15%	SOA: ~25%
		SOA: ~10%	SOA: ~10%	

SOA UPFRONT CAPITAL COST EXPOSURE WITH TC EQUITY OPTION IS \$4.2-5.0B LOWER THAN WITHOUT TC

Impact of Project Capital Cost Risk On State's Upfront Investment (Unlevered)

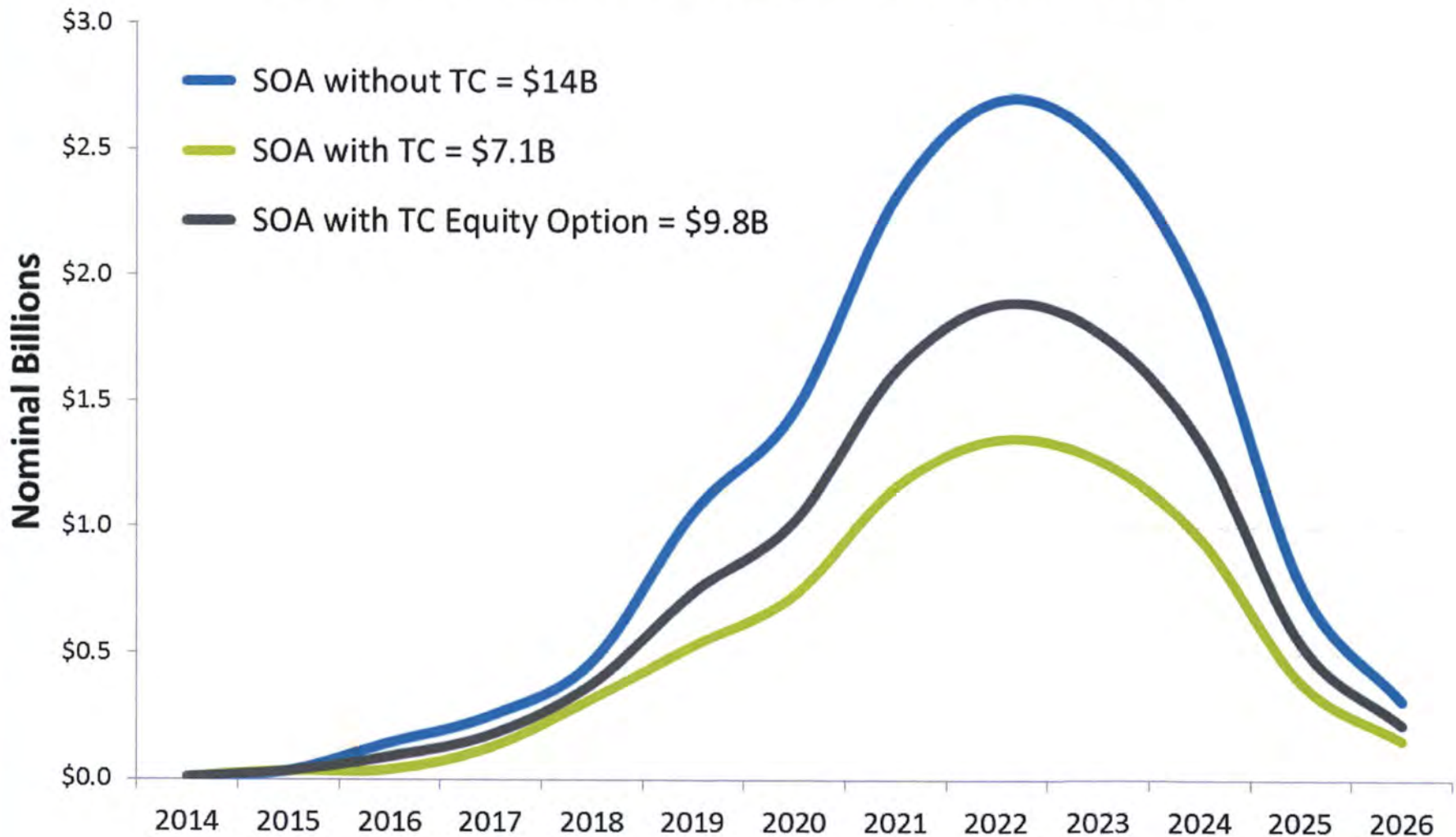


* Assumes State exercises 40% equity buy back with TransCanada at the beginning of FEED



SOA'S ANNUAL INVESTMENT IN THE AKLNG PROJECT WITH TC EQUITY OPTION

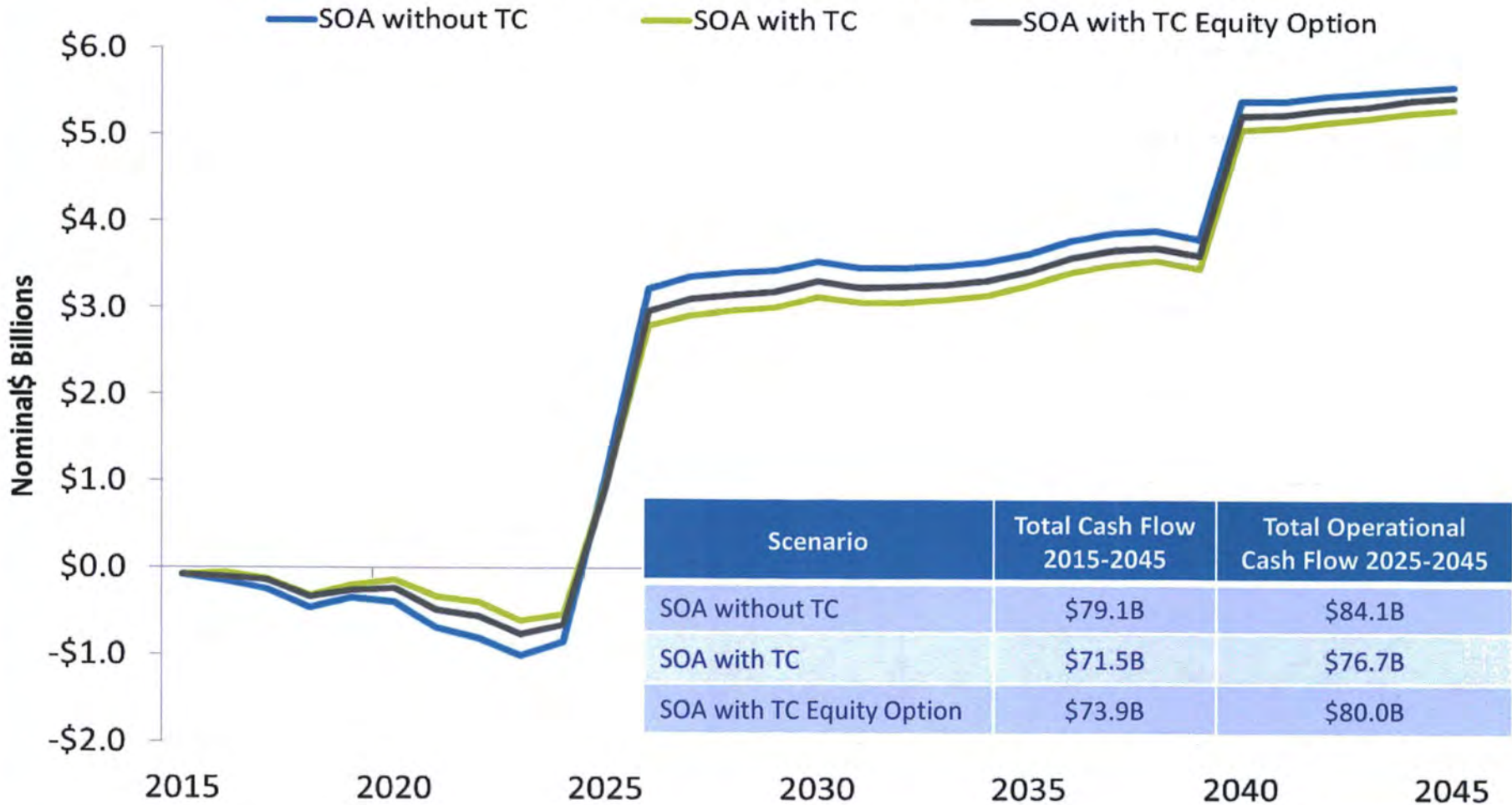
State of Alaska Investment Requirements (Unlevered)



* Assumes Capital Cost escalation of 3%

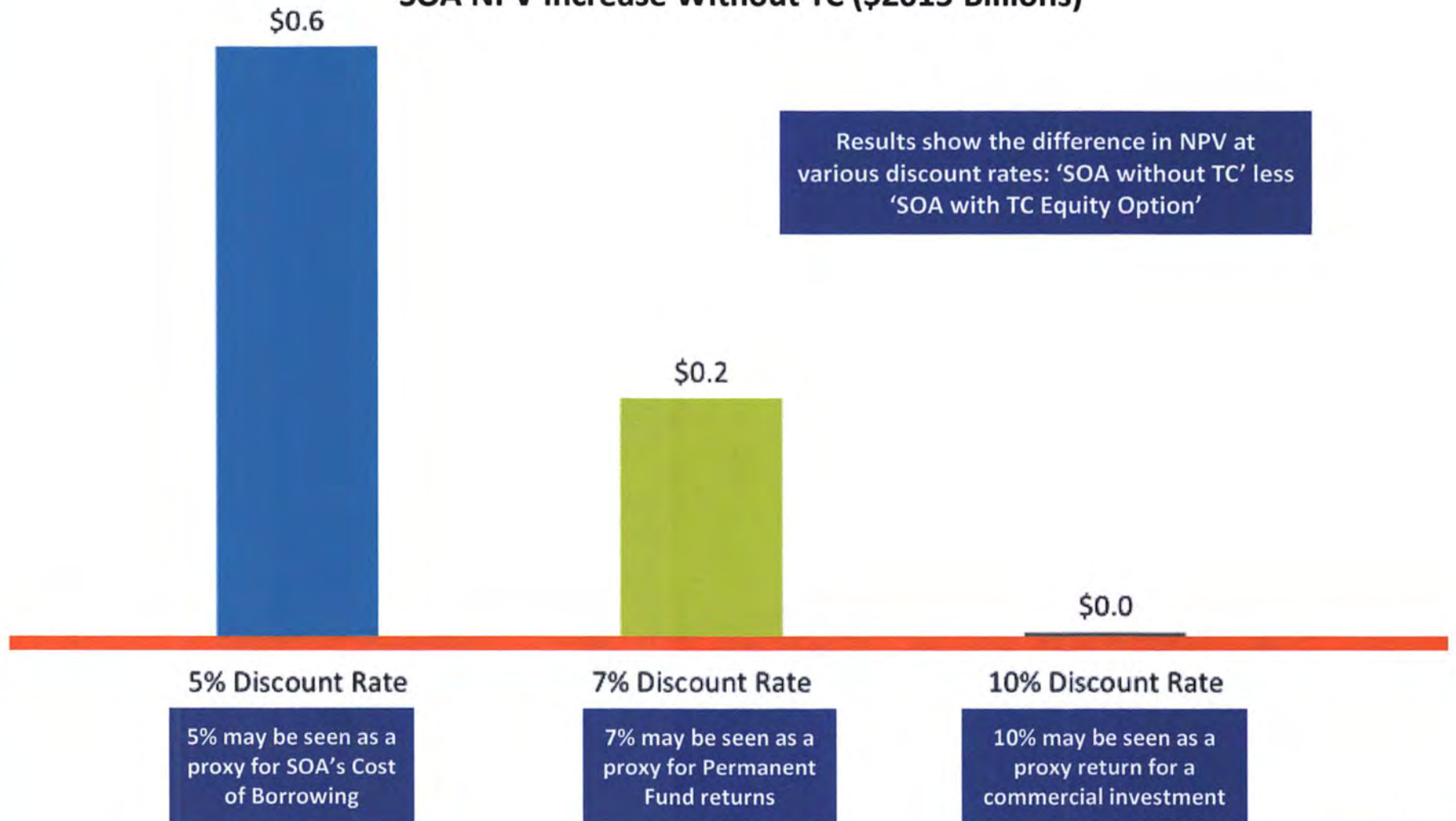
SOA WITH TC EQUITY OPTION WOULD RECEIVE ANNUAL CASH FLOWS OF ~\$220M LOWER THAN WITHOUT TC DURING OPERATIONS

SOA AKLNG Cash Flow Forecast (Over 20 Years)



NPV INCREASE TO THE STATE WITHOUT TC CAN BE BETWEEN \$0-0.6B OVER 20 YEARS WHEN COMPARED TO WITH TC EQUITY OPTION

SOA NPV Increase Without TC (\$2015 Billions)



* Assumes 25% State equity participation



TRANSCANADA'S PARTICIPATION IN AK LNG: KEY ISSUES

OCTOBER 2015

Contents

- 1 Executive summary
- 3 The current role of TransCanada in AK LNG
- 4 Background: 2014 legislative debate on TransCanada participation
- 7 Financial aspects of TransCanada's participation
- 15 Strategic aspects of TransCanada's participation

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EXECUTIVE SUMMARY

TransCanada (TC) notionally holds the state's equity stake in the pipeline and gas treatment plant (GTP) components of Alaska LNG (AK LNG), but from a risk perspective, its participation in the project more closely resembles a loan: TC will pay for expenses that would otherwise be borne by the state, and in return, the state will repay TC a tariff over time (codified through a Firm Transportation Services Agreement, or FTSA). The financial case for keeping or getting rid of TC is too close by itself to be persuasive, especially given all the uncertainties involved with a project at such an early development phase. In particular:

- It seems unlikely that banks and credit rating agencies will treat the state's FTSA with TC in a fundamentally different way than if the state were to borrow equivalent sums directly. Thus, it is not clear that TC will make it easier for the state to finance this project (see p. 11 in this report for more).
- While the state may be able to borrow the funds to support its AK LNG commitments at rate equal to or lower than that charged by TC, it is not clear that it can do so at substantially lower cost, given the current outlook for the state's finances, and the size of the capital requirement (pp. 8-9 for more).
- Neither is it clear that the tariff offered by TC is substantially more expensive than the rate at which the project could secure non-recourse funds from private borrowers; the TC tariff is likely to be more expensive, however, than funds offered by public lenders such as export credit agencies (pp. 9-11 for more).
- If one discounts future cash flows at a rate that correctly accounts for project risk, the difference between keeping TC in and going alone is minimal, especially if the state were to exercise its Equity Option (pp. 11-13 for more).
- The risk of receiving negative netback at the wellhead in a world of low gas prices is slightly higher under TC, but could be effectively mitigated if the state wished to continue the partnership (pp. 13-15 for more).

Given that the purely financial case for keeping or getting rid of TC is not, by itself, persuasive, other, non-financial questions carry particular weight:

- To what extent has TC delivered on the expectations of the state? The assumption, during the SB 138 discussions, was that the state and TC would be highly aligned in all midstream questions since they shared an interest in having as much gas as possible flow through the pipeline. To what extent have such expectations been borne by the facts? What is TC's position on questions such as whether to build a 42 or a 48 inch pipeline? Does TC have the same views as the state on the withdrawal agreements being negotiated? (pp. 15-17 for more).
- How would TC's departure impact the project? TC was selected because it brought considerable experience and expertise in the midstream component. To fully understand the implications of TC leaving, one needs to understand how the workflow will be impacted. How many TC employees are participating in project work and how will that work be affected by a termination event? (p. 17 for more).
- What kind of project structure does the State of Alaska wish to see for AK LNG? On one hand, the project is structured to align ownership of gas with ownership of infrastructure, and in that world, TC's role is less clear. On the other, the state is negotiating agreements that could see one or more producers leave the project, in which case, it would make sense to re-introduce partners such as TC that have an interest in constructing and owning infrastructure (p. 17 for more).

Finally, there is a broader question about the nature of the relationship between the state and TC. The agreement that governs the relationship has certain elements that keep most of the risks of equity ownership with the state, but hand TC broad decision-making powers and enable it to earn an equity rate of return on its participation. In part, this agreement reflected the negotiating strengths of the two sides at the time it was made, under the circumstances of the AGIA license. In the absence of such a constraint, however, now may be the right time to reconsider the balance of risk, reward and control in the partnership with TC.

THE CURRENT ROLE OF TRANSCANADA IN AK LNG

TransCanada's participation in AK LNG was codified in a **Memorandum of Understanding (MOU)** between the State of Alaska (SOA) and TransCanada (TC) in December 2013. The MOU was negotiated alongside a **Heads of Agreement (HOA)** between the State of Alaska (SOA), the three major North Slope producers, and TransCanada, setting out an overall strategic vision for AK LNG.

Heads of Agreement. Under the HOA, the state indicated its intention (subject to negotiations) to take its tax and royalty entitlements for gas production in kind, as gas rather than as cash, which would give the state a 20-25% share of the gas for the AK LNG project. Further, it would hold a corresponding 20-25% of the equity in the project. As an equity partner, it would be responsible for 20-25% of the costs of developing the \$45-\$65 billion project. Under the basic framework of the HOA, gas and infrastructure ownership would thus be aligned.

Memorandum of Understanding. The MOU then proposed assigning the state's 20-25% infrastructure ownership in the gas treatment plant (GTP) and pipeline to TransCanada (TC), while retaining the state's full share in the liquefaction component of the project. Under this arrangement, TC would fully fund the state's development costs for the GTP and pipeline, and be reimbursed with interest for doing so. Should the project proceed, that reimbursement would occur through a tariff on the transportation of the state's share of the gas, which covers the costs of building the infrastructure and transporting the gas plus a return. If the project did not proceed, or if TC at some point left the project, TC would be reimbursed in full, with interest, by the state. While it would notionally hold infrastructure equity, TC's involvement is thus more like a loan; the core project risks would remain with the state, while TC would be a financier and provider of technical expertise and capability.

The MOU essentially provided a term sheet, outlining the basis on which subsequent agreements establishing this relationship with TC would be drawn up. Under the MOU, the state would also have an **Equity Option (EO)**, exercisable at the end of 2015, to **reclaim up to 40% of its original share** in the pipeline and GTP (10% of the total for each) from TC by repaying the corresponding share of TC's development expenses to date with interest.

		PRODUCERS			SOA OPTIONS UNDER HOA AND MOU		
		XOM	BP	COP	HOA	MOU	MOU+EO
	GAS SUPPLY	32%	21%	22%	25%	25%	25%
INFRASTRUCTURE	GTP	32%	21%	22%	25%	TC:25%	TC: 15%, SOA: 10%
	PIPELINE	32%	21%	22%	25%	TC:25%	TC: 15%, SOA: 10%
	LIQUEFACTION	32%	21%	22%	25%	25%	25%

In approving SB138, the legislature authorized the state to negotiate and enter into agreements with TransCanada and the producers of no more than two years duration. These agreements included a **Precedent Agreement (PA)** and **Equity Option Agreement (EOA)** that accompanied the AGIA Dissolution Agreement with TC, based on the terms negotiated in the MOU, and superseding that agreement. The PA and EOA currently govern the terms of the SOA's relationship with TC, but have not yet been made available to the legislature due to confidentiality restrictions.

BACKGROUND: 2014 LEGISLATIVE DEBATE ON TRANSCANADA PARTICIPATION

Original rationale for TransCanada (TC) participation. In the legislative review of the HOA, the MOU and SB 138 that occurred in the 2014 legislative session, the Parnell administration, which had negotiated that MOU, argued strongly that TC brought several advantages to AK LNG, including in particular that:

- TC had a **long history of working on an Alaskan gas pipeline**, most recently as the holder of the Alaska Gasline Inducement Act (AGIA) license. TC brought a wealth of experience, data, institutional knowledge and prior work that AK LNG could leverage. Moreover, TC was **one of the world's premier pipeline companies**, one of only a few having experience with northern pipelines, and its involvement would strengthen the project team in designing, constructing and operating the 800-mile pipeline from the North Slope to tidewater.
- TC was a company that made money by shipping gas. Thus, on the question of future pipeline expandability, **TC's core interests were aligned with the interests of the state**: the more gas that eventually flowed through the pipeline, the better it would be for TC. The state could rely on TC's interests and expertise to ensure that the pipeline would be structured and designed to be as expandable as possible, both technically and commercially. Indeed, the administration argued that they had benefited from TC's expertise at the negotiating table in securing expansion principles in the HOA, and in the various technical discussions on in-state gas options and off-take points.
- TC could make it **easier for the state to finance its share in AK LNG**. As a part owner in AK LNG, the state would be responsible for covering its share of the development costs, which would run into several billion dollars. By bringing TC into the project, the state would have to put upfront a smaller amount of capital; instead, the state would reimburse TC over time for its expenses in AK LNG, in the form of a tariff on SOA gas flowing through the pipeline and GTP.
- Excluding TC from AK LNG could have exposed the state to **liabilities related to the AGIA license**, which entitled TC to damages if the license was suspended, and also hindered the full transfer of AGIA work product to AK LNG until the AGIA license was satisfactorily wound up. In that context, continuing the relationship with TC avoided any potential disruptions and project slippage that could result from any adversarial ending of the AGIA license.

- The MOU provided **'off-ramps'** that meant the question of **TC's ultimate project participation could be revisited** when more project details had been established, and more analysis had been performed.

In presenting this argument, the Parnell administration acknowledged that TC's involvement came with certain costs. In particular, it was understood that the **weighted average cost of capital (WACC) required by TC** to effectively finance the state's share of the GTP and pipeline **might be higher than that required by other potential sources of finance**. Fundamentally, however, it was suggested that any such costs were limited in the context of the overall project, and would be outweighed by the benefits of TC's participation, in terms of capabilities and expertise, expansion-orientation, and continuity from AGIA to AK LNG.

Key concerns expressed during 2014 legislative session. At the same time, several parts of the relationship with TC came under significant scrutiny during the SB 138 conversation in the 2014 legislative session:

- There was concern at the observation that **TC took on limited risk** and that, as a result, in some regards the partnership appeared skewed in TC's favor, with TC earning an equity rate of return on the project without taking on the true risks of equity ownership. If the project failed, TC would be reimbursed for all its expenses to date; if the project's costs escalated, it would earn a higher tariff to compensate for higher costs; if there was a change in long-term interest rates before a Final Investment Decision (FID) was made, its rate of return on debt and equity would adjust accordingly (a provision which is natural for debt but harder to justify for equity). And if TC could not secure financing at terms acceptable to it, it could simply pull out and be reimbursed for its expenses.
- The MOU terms provided the state with **limited levers through which to influence TC's involvement in the project**. Under the MOU, TC would be the general partner of the Limited Partnership that would hold the state's interest in the GTP and the pipeline; in that capacity, TC would

"make all decisions on behalf of the Limited Partnership, provided that the Equity Option Agreement will provide that certain fundamental decisions (e.g. change to distribution policy, winding up of Limited Partnership, sale of significant interest of Limited Partnership in AK LNG) could not be made without the approval of the Optionee (before the option is exercised) or the Limited Partner (after the option is exercised)." (MOU, page 1)

In other words, the state retained certain veto rights but otherwise depended on TC to make decisions that served the state's interests, despite the fact that it was the state, rather than TC that bore the ultimate costs and risks.

- TC participated not just in the pipeline, where it had clear expertise, but also in the GTP, where the relevance of its expertise was less apparent.
- Finally, on the question of 'off-ramps' there was significant discomfort at an MOU clause stating that if the relationship were terminated, the state would have to

offer TC an opportunity to join any new project that was “substantially similar” to AK LNG for 5 years after the termination of the agreement. Legislative scrutiny and resulting negotiations and clarifications during the course of the session served to ensure that that clause would be included in an eventual FTSA, but not the PA that would govern the TC relationship until an FTSA could be signed in late 2015; as a result, **late 2015 would provide the one opportunity** for a clean break should the state wish to **terminate the relationship at that point**.

Centrality of late-2015 ‘off-ramp’. It was this final question of a solid, late-2015 off-ramp that ultimately, for many legislators, provided the necessary reassurance regarding the TC relationship to enable the passage of SB 138. This provision meant that through the course of 2014 and 2015, the state could acquire a more **thorough and detailed understanding of its own ability to finance the project**, and how the costs and benefits of these options compared to those of TC's participation.

Armed with that knowledge, in late 2015 the state could then decide whether to (a) continue the relationship with TC unchanged; (b) exercise its option to acquire 40% of TC's share of the project (10% of each of the GTP and the pipeline); or (c) take the ‘off-ramp’ and terminate the relationship with TC, reimbursing it for its expenses to date. The state would be able to **make this decision after having fully dissolved the AGIA license**, and no longer having the concern over AGIA damages, or the transfer of TC work product to AK LNG being part of the picture.

Options available: extend deadline or terminate. Late 2015 is now here. Ideally, in making further determinations on TC's involvement, under the timeline originally envisioned, the legislature would have had full details of all of the contracts to be signed with other partners, and details of the proposed financial structuring that went with these, including risks of different options, and their impacts on the state's bonding capacity and bond rating. Because of the delays created by difficult negotiations in other areas, however, many of these details will be difficult to present at the same time as the TC decision, since the December 2015 deadline for a decision on TC's ultimate participation still applies despite slippage in other areas.

Clearly, without other agreements in place, the state cannot agree to an FTSA with TC; until it finalizes gas supply agreements and makes a Royalty-In-Kind (RIK) determination, for instance, the state has no gas to ship through a pipeline. The choice that faces the state now is thus **whether to seek to extend the December 2015 deadline for finalizing an FTSA and exercising the Equity Option, or whether the state should terminate its relationship with TC** by reimbursing it its costs incurred to date, with interest.

Financial and strategic costs and benefits. The question of TC's involvement has always been one of evaluating the **potential financial costs** of TC's involvement in the project (in terms of its weighted average cost of capital, compared to the potential borrowing costs of the state) in **comparison to the financial and non-financial benefits TC's involvement might bring**. For that

reason, the remainder of this report will be devoted to an analysis first of the financial, then of the strategic costs and benefits to TC's participation in AK LNG.

FINANCIAL ASPECTS OF TRANSCANADA'S PARTICIPATION

The cost of the implicit 'financing' provided by TransCanada is set by the MOU on a basis common to most regulated infrastructure like pipelines - that of a capital base consisting of the capital cost of the infrastructure, depreciated over time, with a tariff composed of an agreed return on that capital, plus depreciation recovery, operating costs and taxes. Under the MOU, TC's return on their capital deployed in funding the design and construction of their share of the pipeline and GTP is calculated through an agreed capital structure, and a set cost of debt and equity.

Under the MOU, the capitalization structure agreed to is one of 70% debt and 30% equity during development and construction, revised to 75% debt and 25% equity one year after the in-service-date of AK LNG, and remaining in that proportion for the duration of the 25 year contract term. **The base rate set for the return on equity is 12%, while the cost of debt is set at 5%.** Both numbers are subject to a 'rate tracker differential', which tracks the difference between the yield on 30-year US Treasuries between the time of the original signing of the MOU in December 2013, and the time at which a final investment decision (FID) for AK LNG is made. The ultimate capital costs would then be fixed, on the basis of this tracker, at FID.

Ignoring for the moment the effect of the rate tracker, given this capital structure and these returns on debt and equity, the **weighted average cost of capital (WACC) during design and construction would be 7.1% during design and construction, falling to 6.75%** after the first year of operations.

Since the 30 year Treasury yield has fallen by 95 basis points (i.e. 0.95%) since the MOU was signed in December 2013, if one were to imagine it were possible to take FID in mid-October 2015, the resulting costs of capital would be reduced accordingly, to around **6.15% during construction, and 5.8% during operation.** Of course the 30 year Treasury yield will continue to move between now and FID, and in general the likelihood of substantial upward movement must be seen as substantially greater than that of further declines over that time period.

Finally, if TC ceases to be a participant before the final debt and equity rates are set at FID, TC's reimbursement will be with interest (Allowance for Funds Used During Construction, or AFUDC under the terms of the MOU) fixed at the rate of 7.1%.

TransCanada cost of capital vs other US pipelines. A key question during the the 2014 legislative session was the reasonableness of the tariff negotiated with TC in comparison with rates charged by other pipelines in the United States. Analysis prepared by enalytica at that time demonstrated that compared to FERC-regulated pipelines, the TC MOU entailed a capital structure much more heavily weighted toward debt (the lower-cost form of capital), and with a weighted average cost of capital (WACC) near the very bottom for all FERC-reporting pipelines.

Ultimately, however, this comparison may not be the most relevant, or the most important comparison to draw, because of the allocation of risk under the MOU. In many aspects, although under the MOU and subsequent agreements, TC notionally holds the state's equity share in the AK LNG GTP and pipeline components, in reality the state continues to bear most of the true risks of equity ownership, with TC made whole with interest in almost all scenarios. In the amount of project risk that it takes on, ignoring for the moment any other benefits it may provide, **TC is more like a bank or a bond-holder than a true equity participant**, and in many ways it is more logical to compare the financing option that TC provides to that which the state might obtain either through debt financing on the state's balance sheet, or the non-recourse financing that might be available to a state project company.

TransCanada cost of capital vs state balance sheet debt. The state's likely cost of debt in a world in which AK LNG is sanctioned is very difficult to forecast with any degree of accuracy, even if one ignores broader changes that will occur between now and FID to the long-term risk-free interest rate (effectively synonymous with the US Treasury yield), which affect all of the state's financing options more or less equally (including TC, through the rate tracker differential). While the state currently maintains a triple-A credit rating and is able to access fixed-income capital markets at exceptionally low rates, this is a function of the relatively low debt burden the state currently maintains, and its exceptionally high level of savings.

Key factors that will impact the state's ability to raise a significant portion of the roughly \$15 billion needed to fund its share of AK LNG will include:

- the outlooks for the crude oil price and North Slope oil production in the 2020s;
- the trajectory of the state population and state spending in the intervening years;
- the duration of the current period of low oil prices;
- the state's success or otherwise in cutting spending and developing non-oil sources of revenue during the oil price downturn, and its corresponding rate of consumption of savings;
- the performance in the intervening time of the Permanent Fund, and the degree to which, explicitly or implicitly, it is seen to backstop relevant liabilities;
- the extent of the state's future dependence on AK LNG project revenues.

The state has dedicated, specialist advisors regarding its access to debt capital markets, and their advice should be relied on in gauging the state's likely cost of capital across a range of possible scenarios. At the time of writing, only some preliminary numbers from FirstSouthwest (prepared June 3, 2015 and marked 'for discussion purposes only') have been made available to the legislature in considering this question. Even these, however, are useful in considering the extent to which state financing may present advantages over the TC financing option.

The FirstSouthwest analysis provided assumes, reasonably, that if the state can limit debt service costs as a proportion of general fund revenue to 5%, it can maintain its current AAA credit rating, but that as this percentage rises, its rating falls, reaching a level of A2/A when debt service reaches 20% of general fund revenue. It posits a **4.49% rate on taxable bond issuance in 2017 at a AAA rating**, rising to **5.34% at the lowest A2/A rating** contemplated.

The analysis provided suggests that a **~\$15bn bond issuance** in 2017 (roughly the full amount needed to cover the state's anticipated construction costs for AK LNG, though it would not all need to be raised in 2017) **would take the state to the limit of fundraising that could be achieved at a A2/A rating**, implying a cost of debt around the 5.34% level, by FirstSouthwest's numbers. It should be noted that this analysis also relies on the DOR spring 2015 Revenue Sources Book projections for unrestricted general fund revenue, which assume that ANS crude returns to \$110/bbl by 2020, and rises from that point onward. While a world in which this does not occur would make debt raising more difficult and expensive still, such a world would also be one in which AK LNG would be less likely to reach FID.

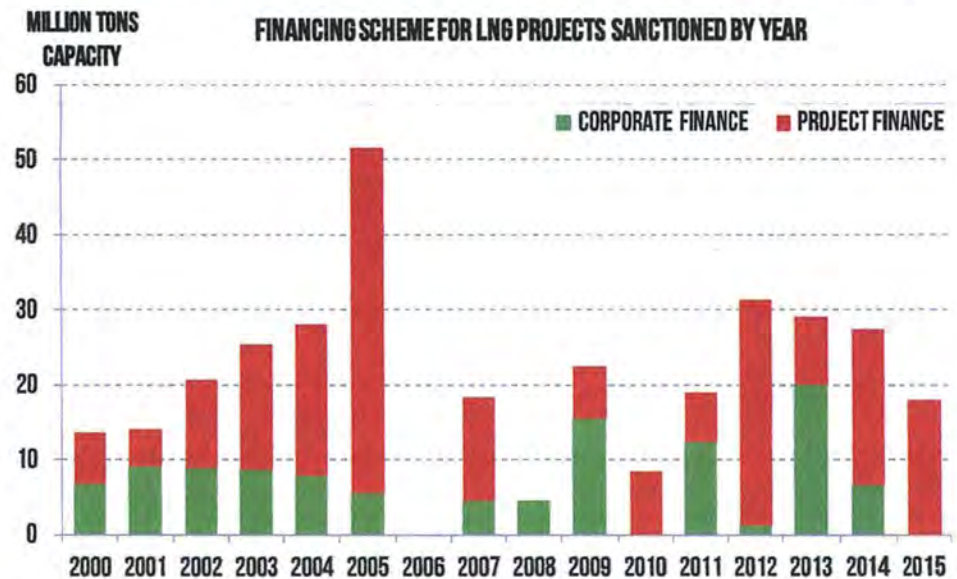
It seems likely that, in most plausible scenarios, if the state chose to raise the funds for its share of AK LNG entirely through debt, and did so through on-balance-sheet, recourse debt (whether general obligation or appropriation bonds), it could do so, although doing so would clearly involve a significant credit-rating downgrade. As the subsequent section will show, this is likely the case regardless of whether TC participates or not. Further, it appears likely that the cost of such debt would, in most reasonable scenarios, be no higher than the cost of financing offered by TC. Indeed, since TC's offer depends largely on leveraging the state's 'full faith and credit', it is hard to see how TC's cost of financing could ever be cheaper than the state's; were the state's credit rating to deteriorate to a point that implied a higher cost of capital, TC could always opt to withdraw, leaving the state with a need to finance directly.

How much lower this cost could be than that of TC participation depends on too many variables to predict with any degree of certainty, but in most likely cases, it seems unlikely to be sufficiently large that the case for proceeding without TC can be convincingly argued on cost-of-capital grounds alone, if there are other major non-financial advantages to TC's participation.

One exception to this would be if the state were successful in obtaining a private letter ruling from the IRS authorizing the state to issue tax-exempt bonds to raise funds for AK LNG. Yields on tax-exempt bonds are far lower than those on taxable ones, so if tax-exempt issuance in support of AK LNG is possible, this would present a major financing advantage. Tax-exempt issuance primarily exists to support public facilities and infrastructure, however, and strict rules govern eligibility for projects with private participants or off-takers. As a result, absent a PRL, the permissibility of tax-exempt issuances remains unclear.

TransCanada cost of capital vs project company non-recourse finance. For many LNG projects, significant amounts of debt financing are raised not on the

balance sheets of their sponsor companies, but by project companies themselves, with limited or no recourse to the sponsors. Such debt is rated primarily not on the financial strength of the sponsor companies, but on the financial strength of LNG buyers, and the firmness of their long-term financial obligations to purchase LNG.



Sources: *analytica* based on company announcements, industry press and reports, and *Project Finance International* annual league tables

The above time series chart, which shows total LNG project capacity sanctioned each year, split between non or limited-recourse financing (also known as project financing), versus sponsor-recourse corporate financing, makes it clear just how strongly established project financing is in the world of LNG projects.

Substantial amounts of project debt have been raised in recent years, with individual projects rating in excess of \$10bn in project debt. The **Ichthys LNG project in Australia raised fully \$20bn of its total \$34bn cost through limited-recourse debt**. Such borrowing, however, brings with it strict lender scrutiny, including rigorous conditions precedent and loan covenants, financial transparency of all project participants to lenders, and additional requirements beyond sovereign regulatory ones in the management of environmental and social risks.

Since project finance transactions are often private between projects and a syndicate of participating banks and official export or credit agencies (ECAs), interest rates on project finance loans are often not publicly available. For a few recent LNG projects in the US Gulf of Mexico, however, data is available on interest rates for non-recourse bond issuance. Sabine Pass Liquefaction, LLC, the project company for **Cheniere Energy's Sabine Pass LNG project, raised close to \$9bn in recent years in limited-recourse bond placements**, using notes falling due between 2021 and 2025, at **interest rates between 5.625% and 6.25%**.

No two projects are alike, but the Sabine Pass figures may provide a useful lower bound on the potential cost for non-recourse project debt for AK LNG. While again, this lower bound is cheaper than the 5.8% to 6.75% range implied by movements in the rate tracker for the TC contract (based on the capital structure used in operation), the gap is not large enough, given the many variables involved, to suggest that this avenue is likely to present a major cost-of-capital savings, if any, for the project in comparison to the option presented by TC.

The same is not true of funds obtained from public sector lending bodies like export credit agencies (ECAs), which are major lenders in the market for LNG project finance, and frequently lend at advantageous rates. ECA project financing could be a compelling piece of a overall financing strategy for AK LNG.

Impact of TransCanada participation on state debt capacity. One of the arguments put forward by the Parnell administration in 2014 in advocating TC's participation in AK LNG was the limited debt capacity of the state. Given the significant impact of the large-scale borrowing required by AK LNG on the state's credit rating, and given the likelihood of other bonding needs by the state, TC participation was presented as a means to reduce the amount of debt the state would need to take on, and better preserve the state's credit rating and debt capacity available to meet other needs.

This has always been the least persuasive of the arguments made in favor of TC participation. While there are doubtless many subtleties that can be debated regarding government accounting rules, and specific treatments that might apply, the general intention of standards bodies like the Government Accounting Standards Board (GASB) seems clear; where a contract pledges the full faith and credit of the state, and entails a major and highly material, firm, long-term financial obligation of the sort entailed by an FTSA, such a contract should be capitalized as a liability on the state's balance sheet at the present value of the future contract payments; in other words for all intents and purposes, such a contract should be treated as equivalent to debt, including in its impact on debt service and debt capacity.

There are many reasons to believe that ratings agencies would take a similar view of an FTSA with TC, and relatively few reasons to believe that the state can incur a firm financial obligation in the form of an FTSA, and not see a major impact on its credit rating and debt capacity.

Net Present Value analysis of TransCanada participation. As with any form of financing, TC's involvement in AK LNG has different impacts across different time periods. As Black & Veatch's modeling shows, it reduces the state's up-front cash-calls for development and construction by around half, from \$14bn to \$7bn, but, assuming the state structures capital for the project with 70% debt and 30% equity, it reduces the corresponding cashflows the state receives over the life of the project by around \$400mm each year in nominal terms. Any analysis that focuses only on one side or another of this intertemporal balance is unhelpful.

Fortunately, financial economists have for a long time used a simple measure to equilibrate the differential impacts of investment decisions over time, that accounts for the fact that a dollar in the future is worth less than a dollar today. This measure is Net Present Value (NPV) - the value of a future stream of cashflows, discounted to take into account the time value of money, so that we can reliably compare widely differing cashflows from different investment opportunities on a completely equal footing.

In order to calculate the NPV of differing investment alternatives, however, we must first establish a discount rate that we can agree correctly represents the time value of money. How do we determine what the correct discount rate is for the State of Alaska?

Some might suggest that the correct rate to use is the state's own bond rate - its cost of debt. Others might suggest that we should instead use the rate given by the state's current return on its biggest pool of assets - the Permanent Fund return of 8%. Both of these, however, can be shown to be clearly and unambiguously the incorrect approaches to take to this problem.

Almost all modern finance textbooks agree on one point above all: **the correct discount rate to apply in evaluating the present value of any investment opportunity**, by any investor, whether the state, a company or an individual, is the weighted average cost of capital that represents the **return that market investors would require to hold a security representing a piece of that investment as part of a well-diversified investment portfolio**.

This is a universally accepted concept in financial economics, because it represents the best means available of empirically measuring and taking into account the different risks posed by different investment opportunities in determining whether or not they are attractive investments. Though the state's long-term bond rate for large scale capital raising may be 5%, we wouldn't want the state to invest in a highly leveraged, high-risk hedge fund that could lose all of the state's money tomorrow, for a 5% return. Indeed, we wouldn't even want the state to make such an investment for the 8% return it receives from the relatively conservatively managed Permanent Fund; were the state to take such a significant risk, like any investor it would need to ensure it was suitably compensated for the risks it took.

How, then, do we assess the risks of an LNG project in determining the appropriate weighted average cost of capital to use in discounting the cashflows that the state expects to receive from AK LNG? The best way to do this is to look at companies whose investments are LNG projects, upstream oil and gas projects, pipeline projects, or some combination of these, and assess the returns required to be willing to hold their equity as part of a well-diversified stock portfolio. In other words, **rather than looking at the returns of the Permanent Fund** to determine the discount rate the state should use in assessing its investment in an LNG project, we need to look at **the returns that the Permanent Fund would require in order to be willing to hold stock in an LNG company, an oil and gas company, or a pipeline company, as part of its portfolio**.

Fortunately, a preliminary version of this analysis has already been undertaken by the state's financial advisor Lazard, and is provided for information in the appendices of the report they submitted in early 2015. These appendices provide the data required to estimate the required returns on such equity. By performing a few additional straightforward calculations, **we can calculate an appropriate overall weighted average cost of capital (WACC) at which we should discount the cashflows of an LNG project.** While it is possible to arrive at different interpretations when considering which companies should be included, or how the tax-free status of the state in regard to the impact of debt should be considered, in any possible range of analyses, one arrives at a number of **at least 9%, and in most cases 10% or above.**

One additional complication, however, must be considered in evaluating the appropriate discount rate to use. Not all of the cashflows to the state from AK LNG are returns on the state's investment in the form of revenues from LNG sold. Some of the revenues will come from property taxes paid by the other project participants. Since these are not exposed to commodity risks (though if property taxes are charged on a \$/mcf basis, they will be exposed to other project risks), and are tax revenues rather than investment proceeds, some argument exists for discounting these cashflows at a lower rate. However, even if these represented fully a quarter of the revenues, and we discounted these at an aggressively low rate of 5%, while discounting the remainder of the revenues at a rate of 10%, we would end up with a weighted average of 8.75%. Discounting the state's expected revenues from AK LNG at a rate lower than that for any decision making purpose is very difficult to justify.

The *TransCanada Participation Decision* analysis provided by Black & Veatch examines the NPV difference to the State of Alaska of a project structure with TC and without, assuming that any project participation not funded by TC is supported by the state through 70% debt and 30% equity, at the same 5% cost of debt that applies to debt (but not equity) under the deal with TC. Slide 25 presents this analysis assuming the state does not exercise its Equity Option, while slide 56 presents it in the case of exercise of the EO.

In both cases, at a discount rate of 10%, there is no material NPV difference in the results between TC participation or pure state financing. Even using a discount rate as low as 7%, there is an NPV cost of only \$600mm to TC participation in the case that the state does not exercise its equity option, falling to only \$200mm in the EO case. These numbers compare to an NPV for the project overall (assuming no TC participation) of \$9bn. Clearly, while there may be a financial cost to the state from TC's participation, that cost is limited in the overall project context, especially if one discounts at an appropriate rate. Furthermore, the bulk of any such cost can be mitigated simply through exercise of the Equity Option.

'Negative Netback' risk from TransCanada participation. By taking gas in kind rather than as value at the wellhead, the state exposes itself to certain risks that it would not, were it possible to structure a project that involved neither a state equity

investment nor royalty in kind / tax as gas. Principal among these is the possibility that the fixed costs the state must incur to transport its gas might, in periods of low LNG prices, exceed the sales price it receives for its LNG - in other words, that after subtracting all of the costs of transportation, in periods of adverse pricing, the state could effectively be paying money to sell its LNG.

If the state were to fully fund its infrastructure through equity, it would not run this risk, except in cases so extreme where the cost of LNG were so low as to not cover the operating costs of the AK LNG facilities. In an all-equity case, the risks to the state would be those of not making an acceptable rate of return on its investment, rather than of actual losses on LNG sold.

Financial leverage, however, complicates this picture. That leverage may come through debts to banks or bond-holders, or in the form of an FTSA commitment to TC. Both involve a senior, fixed claim on the cashflows from the state's share of AK LNG, which must be met before the state receives its cash. In stressed price environments where the costs of these fixed claims are higher than the proceeds of selling LNG, the state runs the risk of 'negative netback'. Thoroughly understanding and effectively managing or mitigating this risk is clearly an essential precondition to the state making the RIK election on which the current AK LNG structure is based.

Black & Veatch examine this risk on slides 27 and 28 of their analysis, showing that the state's "midstream cost obligations are expected to be \$8.20/MMBtu with TC compared to \$7.30/MMBtu without TC". This is an important analysis to understand in evaluating the financial costs and benefits of TC participation, however some key facts should be born in mind in considering it.

Most important to understand is the fact that the analysis looks at LNG shipping and marketing revenues to the state, not all of the state's revenues from AK LNG. In particular, property and state income taxes from other project participants to the state are not considered in the analysis; this represents strictly the expected revenues and costs of the state 'project company'. This is a sound distinction; it will be the state project company that needs to pay these costs, and times where company revenues are insufficient to cover them will pose significant problems.

However the payment and receipt of property tax is a key distinction between TC participation and non-participation. As a private sector company, TC is required to pay property taxes on its ownership of the pipeline and GTP, where the state would not. These taxes ultimately come back to the state, broadly defined, but in general are shared with municipalities rather than all revenue being unrestricted general fund revenue for the state.

The Black & Veatch negative netback analysis assumes a scenario where the state funds all project capital calls not met by TC 100% through debt. The analysis assumes that the cost of debt for the state is the same 5% that is the return on debt to TC under the MOU.

The cost difference calculated by Black & Veatch between TC participation and TC exit is thus driven by two key things; 12% the return on equity that must also be

paid to TC (on the 25% of TC's capital base that would be funded through equity for rate-making purposes), and the taxes that TC must pay that the state would not, the vast majority of which are property taxes. Because the analysis only looks at the project company, the fact that these taxes are paid to the state (broadly defined) is excluded from the picture. Of the \$0.90/MMBtu cost difference calculated by Black & Veatch, \$0.50 is due to TC's return on equity and federal income tax liability, while the remaining \$0.40 consists of payments made to the state (including municipalities) in the form of property tax and, to a lesser extent, state corporate income tax.

Thus, a large part of this negative netback risk remains within state control, depending on the state's chosen structuring of property tax sharing with municipalities. Since any increase in property taxes as a result of TC participation is purely a function of a chosen financial structure, it should be possible to offset this in distribution arrangements, and even to hold some of the proceeds in reserve for use during times of extreme negative price exposure. This would eliminate the portion of the difference between the two scenarios that is driven by property taxes.

The remaining \$0.50/MMBtu cost difference due to TC's return on equity could then be substantially further reduced through the state's exercise of its Equity Option to 'buy back' up to 40% of the state's 25% stake in the GTP and the pipeline.

STRATEGIC ASPECTS OF TRANSCANADA'S PARTICIPATION

Financially, the transaction with TransCanada is thus a close call that depends on many parameters that are unknowable at this time. While in purely financial terms, the state's position in AK LNG is unlikely to be impaired as a result of terminating its relationship with TC, the financial benefits that might come from termination are at this point uncertain and highly contingent.

The merits of the case for terminating or retaining TC must thus rest on a fundamentally different set of questions; questions that reassess the initial assumptions around the strategic benefits of the TC partnership. Almost two years into this partnership, have these benefits materialized?

Expansion orientation. When the Parnell administration proposed the TC partnership, it was argued that TC would be a strong, firmly expansion-oriented partner that would use its experience and expertise to ensure the future expandability of the pipeline, and that would be capable of providing the capital and capabilities for future expansions with minimal additional requirements on the state. After two years of seeing this partnership operating in practice, we should be in a much better position to understand whether or not this is truly the case, especially in light of recent moves by the Walker administration to have the AK LNG project perform detailed engineering for a 48 inch rather than a 42 inch pipe. Key questions that must be answered here are:

- In the debate over the best sizing of the pipeline, how has TC's expertise contributed to the debate?

- Has TC's participation in fact helped to counterbalance the narrower interest of the producers in securing a project that is more expansion oriented, to the degree originally hoped?

Control, interest alignment and transparency. The question of expansion-orientation is crucial both because it was a centerpiece of the Parnell administration's argument for TC's participation, and also because it speaks to a broader issue; the question of alignment of interests between TC and the state. This alignment is crucial, because under the terms of the MOU, the state has assigned effective control over its share in the Pipeline and GTP to TC; even were it to exercise its Equity Option under the MOU, it would remain a Limited Partner, while TC is the General Partner, entitled under the contract to make decisions autonomously, requiring state approval only on "certain fundamental decisions (e.g. change to distribution policy, winding up of Limited Partnership, sale of significant interest of Limited Partnership in AK LNG)". If, in its autonomous decision-making, TC's interests and decisions have not aligned well with the interests of the state, or if state visibility into those components of the project have been fundamentally compromised by the degree of control assigned to TC under the contract, that by itself could be a compelling reason to reconsider the relationship. Key questions to be answered here are:

- Has the MOU structure with TC as General Partner worked for the state in ensuring adequate control and access to information?

Impact on project staffing and expertise. TC's pipeline expertise and its long history of working on an Alaskan gas pipeline have been widely viewed as key assets TC brings to this partnership. TC staff occupy numerous key pipeline positions within the AK LNG pipeline organization chart. What would be the impact in project staffing, operations and relevant expertise of the state terminating this relationship? Key questions to be answered here are:

- What key positions in the AK LNG project organization are currently filled by TC staff?
- What plans are in place to ensure continued access to equivalent expertise in the event of termination?

AK LNG strategic vision. Even more than these questions, perhaps the most important question to ask is also the biggest and broadest - **what kind of project does the state wish AK LNG to become?** Thus far, AK LNG has been conceived and designed as an integrated project where ownership of gas matches ownership of infrastructure. All the agreements governing the relationship between the parties are structured based on this principle, in order to create a structure in which the different parties view the investment in terms as similar as possible to each other - the core of true partner alignment. Viewed from this basis, TC's participation has always seemed somewhat out of place: it is the only participant that has neither gas nor any stake in the liquefaction facility, and it alters the way the state, as a partner, views its participation and its decision making in the project as a whole. If partner

alignment through equal ownership of gas and infrastructure remains a key consideration, TC's participation is an obstacle to that aim.

More recently, however, the Walker administration has been vocal in advancing principles that could reshape the project's structure: for instance, in seeking to negotiate withdrawal agreements that might compel parties to sell their gas to the project at the wellhead or to toll gas through the infrastructure. Similarly, the move to consider a 48 rather than a 42 inch pipeline places the question of expansions involving gas holders not currently part of AK LNG front and center. In all of these cases, there could be major benefits to the presence in the project of a company like TC - one that can provide the expertise and funding for expansions, and move the gas of participants that do not own infrastructure to market without requiring major investments by the state. Key questions to ask here are:

- Are partner alignment through common shares of gas and infrastructure ownership still the key principles behind the structuring of AK LNG?
- How do these principles relate to efforts to sign withdrawal agreements with project partners?
- Who would own the infrastructure to monetize the gas of a partner that withdrew? Would the financial burden and risk fall on the state?
- If TC were not involved in the project, who would be responsible for the engineering and commercial work behind future pipeline expansions to accommodate gas not owned by the producers?
- If the burden of future expansions were placed on the state, what plans does the state have in place to ensure it has these capabilities?

TRANSCANADA AKLNG PARTICIPATION DECISION PRIMER

OFFICE OF THE GOVERNOR



THE STATE
of **ALASKA**
GOVERNOR BILL WALKER

24 OCTOBER 2015

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1.0 Executive Summary

Background: In June 2014, the State of Alaska (SOA) and TransCanada Alaska Midstream LP (TransCanada) entered into a key agreement authorizing TransCanada to pay the upfront capital costs and hold the State's 25 percent share of ownership relative to the midstream components of the Alaska LNG (AKLNG) Project. These midstream components are the Gas Treatment Plant (GTP) and pipeline portions of the overall project.

The agreement, called the Precedent Agreement (PA), was based on terms of a Memorandum of Understanding (MOU) between the State and TransCanada signed in December 2013. While the Alaska Legislature was not a party to this agreement, it reviewed and debated the terms of the MOU during the 2014 legislative session. Under the PA, TransCanada pays upfront capital costs related to the State's share of the AKLNG midstream with the agreement that the State will repay all of TransCanada's costs with interest whether or not the AKLNG project is completed.

A critical component of the original MOU as well as the PA is that the State is authorized to take back its equity share of the AKLNG midstream components by exercising off-ramps designed in the agreement.

Decision at hand: Per the terms of the PA, the State is now faced with a December 31, 2015 deadline to make a decision on whether to take back TransCanada's share and have direct equity participation in the AKLNG midstream. To do so would require termination of the PA. Under the PA's terms, by December 31, the State is obligated to either enter into a Firm Transportation Services Agreement (FTSA) with TransCanada or terminate the PA. Alternatively, if agreeable to TransCanada, the State can negotiate to extend the date for entering into an FTSA beyond December 2015.

Recommendation: The State administration recommends termination of the TransCanada relationship by December 2015 and replacing it with the State's direct participation in the AKLNG midstream. The State administration expects this path to allow the State to better manage the obligation the State has for AKLNG midstream costs whether or not the project proceeds, increase the overall economics of the project to the State, and allow the State to have more direct voting rights on key AKLNG issues in return for its investment.

2.0 Introduction

The SOA is faced with the strategically important decision of whether to terminate the existing PA, which grants TransCanada a portion of SOA's equity and decision making responsibilities in the AKLNG Project. The decision hinges on the SOA's desire to either increase its direct participation in the Project and gain its full equity and voting rights equal to its share of gas or limit the upfront financial exposure for the SOA while giving up more control.

The State has two main options:

1. Terminate the PA by December 31, 2015 and reimburse TransCanada for its costs incurred to date (plus approximately 7% interest) – SOA increases overall equity and voting rights to 25%, which equals the SOA's share of gas;
2. Execute an FTSA with TransCanada by December 31, 2015; TransCanada would continue to incur costs on behalf of the SOA unless there is a termination at a later date, at which point the SOA will have to reimburse TransCanada's costs (plus approximately 7% interest)¹

Note that option 2, executing an FTSA with TransCanada by December 31, 2015, would be premature and very risky from the State's perspective. The original December 2015 deadline to execute an FTSA was premised on an expectation that various project enabling agreements would be finalized to facilitate the State entering into any long-term transportation agreement and the associated guaranteed payments to TransCanada. If the SOA decides to continue the relationship with TransCanada, an extension of the deadline to execute an FTSA will need to be negotiated with TransCanada, assuming TransCanada is willing to consider that.

It is the recommendation of the administration to proceed with termination of the PA and to reimburse TransCanada for its costs incurred to date. As discussed in this primer, the administration believes that this is the best decision for the SOA, as regaining full voting rights will ensure the SOA is able to achieve the optimal value from the Project while enabling the SOA to actively manage risks.

3.0 TransCanada Precedent Agreement

The SOA entered into the PA with TransCanada in 2014 as a result of the decision to shift efforts from the Alaska Gasline Inducement Act (AGIA) project (also known as the Alaska Pipeline Project (APP)) to the AKLNG Project. TransCanada was the State's licensee under AGIA and had rights to the work product developed under those efforts. While TransCanada's work on AGIA and APP allowed smooth transition into pre-FEED for the AKLNG Project and the use of AGIA work products in the development of the AKLNG Project, the agreement with TransCanada was designed to provide the State (and TransCanada) with several off-ramps as the AKLNG Project moved through its different development stages. The State now believes that it is time to exercise an off ramp before December 31, 2015, and terminate its relationship with TransCanada.

¹ The State also has a third option: exercise its option to acquire 40% of the equity of the TransCanada entity that will own the 25% of the AKLNG midstream. This option is not discussed in this primer but in general it has many of the same pros and cons associated with option 2 above, but to a somewhat lesser degree. (e.g., not full voting rights and some limitation on the upfront financial exposure).

4.0 Why is Termination of the TC Relationship in the State's Best Interests?

First, it is important to understand a fundamental element of the structure of the SOA's current relationship with TransCanada. Under the current agreement, TransCanada pays the upfront costs related to the AKLNG midstream and the State has a contractual obligation to repay all of TransCanada's internal and project related costs with interest whether or not the Project is completed. The decision is not, whether or not, to pay TransCanada; the decision is whether to pay TransCanada a lower amount now or pay them a much larger amount later. Either way the State will owe payment to TC for holding our portion of the equity in the AKLNG midstream. This fact holds true whether or not the Project goes forward. In other words, the State ultimately bears all the development cost and risk associated with its equity ownership of the Project, regardless of TransCanada's participation.

ALIGNMENT & VOTING RIGHTS: Terminating the PA allows the State to better align its voting interest in the Project with its ownership percentage of gas. Currently, the SOA is estimated to receive 25% of the gas from Project; however, with TransCanada's equity participation in the midstream portion of the Project, the SOA only retains 25% equity in the LNG plant. As a result, the SOA's equity participation in the entire project, which determines the weight of voting rights, is only ~12.5% (LNG plant is expected to be approximately 50% of total cost). It should be noted that each of the Producers have alignment between their share of equity and gas in the project and hence the State is the only party currently without this alignment.

Under the current arrangement, TransCanada serves as the SOA's midstream participant in the joint venture agreement and holds the SOA's 25% equity share in the Project midstream. As a result, TransCanada makes decisions that are motivated by creating value for its shareholders, which are sometimes but not always aligned with the long-term interests of the State's shareholders, our citizens. To maintain independence in its control of the midstream segment, TransCanada is expected to require separate voting rights from those of the State for the midstream segment and equal voting rights with respect to AGDC with respect to matters that affect both the midstream and the LNG plant. By removing TransCanada, the SOA would gain voting rights equal to its gas share and have more direct influence over key decisions such as Project budget and schedule for the midstream portion. Importantly, the State would have more direct and timely access to information related to the AKLNG Project midstream

ECONOMIC BENEFIT: In addition to the misalignment of equity interest and share of gas in the project, the SOA may also be positioned to lose value in the Project by having TransCanada as an equity participant. The financial participation of TransCanada comes at a borrowing cost of ~7%. The SOA's borrowing costs have historically been lower than TransCanada's ~7% weighted cost of capital and the Department of Revenue (DOR) has opined that, in the future, the SOA's borrowing costs are expected to be lower than TransCanada's for the AKLNG Project. According to Black &

Veatch's report released on September 30, based on DOR's view of the SOA's ability to borrow funds at a lower cost, the SOA could realize up to \$400 million of additional annual net cash flows from the Project (depending on the actual final borrowing costs²) by financing the midstream portion of the Project itself. Even if the State experiences a credit downgrade and has a higher cost of capital, it is still expected to achieve higher annual net cash flows without TransCanada.

In other words, once the Project is in operation, the SOA would make a tariff payment to TransCanada that could exceed, by several hundred million dollars per year, the costs that it would otherwise owe to lenders at a lesser rate through direct state ownership. This incremental cost would also create additional risk of needing Legislative appropriations for the State to cover instances in which revenue from its gas sales is insufficient to cover its tariff costs to TransCanada (which will include, in addition to bank financing costs, a component to compensate TransCanada for their equity investment). As described by Black & Veatch's report, with TransCanada, the cost level that the State's revenues need to cover are expected to be as much as \$1/MMBtu higher than without TransCanada.

Additionally, the State's financial advisor, FirstSouthwest believes that a decision to terminate the PA with TransCanada will not, in and of itself, result in a downgrade of the State's credit rating. The State is already committed to pay the costs of TransCanada's involvement in the Project, so the State assuming TransCanada's costs does not increase the State's commitments. To the contrary, as the State's overall debt costs related to the Project are projected to be reduced in light of lower financing costs, the termination should be viewed by the credit ratings agencies as a net positive for the State. While the State may have to come up with funds on an accelerated basis if the agreement with TransCanada is terminated, FirstSouthwest believes that these funding amounts are well within the SOA's ability to raise funds. FirstSouthwest has noted that under both the TransCanada financing option and a State financing option, the State should anticipate a reduction in the State's credit rating during the construction period for the Project while no gas sale revenues are being generated, with the credit rating beginning to recover once gas sale revenues become established. First Southwest further noted that since the credit ratings agencies will consider the TransCanada financing option as being similar to a State debt obligation in their credit analyses, the magnitude of the credit rating reduction should not be greater if TransCanada is terminated, and could instead be mitigated by State financing as noted above.

5.0 Why Terminate TC now?

There are several reasons why the Administration believes terminating the PA by December 31, 2015 is the preferred path for the SOA rather than negotiating an extension to a later date.

MANAGE FINANCIAL RISK: First, there are significant financial implications to the SOA if the PA is not terminated but the Project does not progress to completion. The benefit from continued

² It should be noted that if the State's borrowing costs are higher than generally presumed, then the additional annual cash flow benefit to terminating the PA with TransCanada could be less than indicated here.

TransCanada involvement stems from the potential reduction in State appropriations during the Project's development phase if indeed the project progresses to completion. This benefit, however, will be entirely eroded and will require even larger State appropriations (reflecting payments to TransCanada for interest and their internal costs) if the Project does not progress to completion. This is because under the PA terms, there is no sharing between the State and TransCanada of project development or construction risks; the State bears these risks in their entirety:

- If the Project is terminated prior to the end of Pre-FEED, then the State will need to reimburse TransCanada for its expenditures to date, plus interest, within the time period established in the PA; a higher interest rate applies if the payment is made later;
- If the Project is terminated during or at the conclusion of FEED the State is expected to owe TransCanada its development costs plus interest, although that would have to be agreed as part of the FTSA;
- If the Project is terminated during construction, the State is expected to owe TransCanada its share of the construction costs plus interest, although that would have to be agreed as part of the FTSA. Assuming that is true, then the SOA's cost responsibility would be higher than it would have been without TransCanada.

Accordingly, any financial value of TransCanada's involvement comes only if the project is indeed brought into operation. Should the project fail, then a very substantial, one-time appropriation would likely need to be assembled very quickly to cover all prior development costs and TransCanada's internal costs, plus associated interest. That appropriation would include not only the funds involved in the currently-requested appropriation for reimbursing TransCanada, but also all such amounts subsequently spent. Finally, borrowing costs at such time would reflect the lender community's knowledge that the State's path to a future revenue-generating gasline project had been halted or delayed; that is, they would likely be higher than they are today.

Put differently, if it assumes full and direct ownership in the Project now, the State today enjoys certain inherent risk mitigation opportunities, in the way of low borrowing costs, should the Project not proceed. Not only are interest rates historically low, but lenders also recognize that the State's finances may be importantly boosted in the future from a successful gasline project. In the event of Project failure at least one, and perhaps both, of these mitigating factors may be absent.

AVOID BACK-IN RIGHTS: A second reason for terminating the PA now is that unlike the PA, the proposed FTSA is expected to include a commitment to give "back-in" rights for TransCanada. The back-in right states that within five years of exercising its termination option, if the State participates in a pipeline project to commercialize North Slope gas that is substantially similar to the AKLNG project, the State would need to offer TransCanada an option to participate in the GTP and pipelines of that project under similar terms. Terminating TC's participation now would give the State a clean off-ramp without needing to offer any back-in rights.

INFLUENCE DESIGN DECISIONS: Finally, certain key project decisions are slated to be made in the next six months. There is a fundamental difference between the State's and the producers' (and potentially TransCanada's) primary decision criteria for these decisions. By terminating the PA with TransCanada, the State would gain voting rights equal to its gas share and have a more direct

influence over key decisions related to the midstream such as Project budget, schedule and by-product handling. In addition, terminating the PA with TransCanada is expected to facilitate simpler and more efficient resolution of voting rights in AKLNG governance agreements currently being negotiated.

6.0 What are the Immediate Implications for State of Alaska?

FINANCIAL IMPACT: The most significant impact of terminating the PA with TransCanada will be financial. If the SOA assumes TransCanada's role in the midstream of the Project, then the SOA will also have to assume the upfront cash calls responsibility for a full 25% share of project development and construction costs. If the PA is terminated, the SOA will have to reimburse TransCanada for any direct project payments they've made since January 2014 as well as their related internal management costs and a 7.1% carrying cost. It is estimated that this will total approximately \$70 million through the end of 2015. The additional SOA costs to complete the midstream Pre-FEED work in 2016 would be ~\$61 million per Alaska Gasline Development Company (AGDC) estimates based on AKLNG pre-FEED cost estimates. If the project moves into final construction, the SOA will be responsible for arranging financing of approximately \$13-14.0 billion, or about twice what would have been needed with TransCanada. TransCanada's continued involvement in the project would reduce the SOAs share of direct Midstream financing during development and construction. However, the SOA would still be obligated through the FTSA to ultimately repay TC's capital invested.

TECHNICAL IMPACT: A secondary consequence of terminating the PA would be the need to replace the technical expertise that TransCanada provides to the Project. However, the AKLNG Project partners have worldwide experience and the resources to be able to step into the pipeline lead role and associated technical positions currently staffed by TransCanada employees.

Alaska Gasline Development Company (AGDC) has recently completed development of Pre-FEED and FEED for the Alaska Stand Alone Pipeline (ASAP) project, on time and under budget. The AGDC team is available on an interim basis to support the State's interest in a natural gas pipeline from the North Slope. AGDC's technical staff is familiar with Alaska-specific design and construction issues that are critical for AKLNG project success. AGDC assets include the proposed SOA right-of-way (RoW) for most of the pipeline alignment and the Federal land RoWs are expected to be granted in mid-2016. Additionally, AGDC has taken over TC's role of coordinating the AKLNG Parties in the owners' review and guidance on the Federal Energy Regulatory Commission (FERC) National Environmental Policy Act (NEPA) resource report filing for the Project.

SOURCE OF FINANCING: Lastly, by terminating the PA with TransCanada, the SOA eliminates a source of funding. As discussed previously, this does not pose a challenge to the SOA's ability to finance their portion of the project. However, if one of the producers decides to withdraw from the Project, having TransCanada as a participant could provide more options to fund the withdrawn producer's portion. It should be noted that depending on the timing of any withdrawal by one of the producers, other partners including potential LNG buyers may be willing to step in and invest in the Project.

7.0 Conclusions & Recommendations

The current arrangement with TransCanada was designed to provide the State (and TransCanada) with several off-ramps as the AKLNG Project moved through its different development stages, including an important clean off-ramp for the State in December 2015. The State administration recommends termination of the TransCanada relationship by December 2015 and replacing it with the State's direct participation in the AKLNG midstream. As described in the assessment above, the exercise of this off-ramp is expected to

- create greater alignment and more direct voting rights on key AKLNG issues in return for its investment,
- help the State better manage its obligations for AKLNG midstream costs whether or not the project proceeds, and
- improve the overall economics of the project to the State



TransCanada's AKLNG Participation: Financing Issues

Special Session
October 24, 2015



Introduction

An exit by TransCanada (TC) from the AKLNG project has financial implications to the State of Alaska:

- Immediate impact: The State will be responsible for funding the reimbursement of TC's Midstream development costs, as required under the Precedent Agreement (PA)
- Going forward: The State will be responsible for funding its share of the Midstream project costs, which would have been funded by TC

This presentation addresses the following issues/questions related to the impact of TC's exit on the State's financial position, credit rating and borrowing capacity:

- What will be the **impact on the State's credit rating and borrowing capacity**?
- **At what cost** is the State expected to finance its share of Midstream costs, and how does such cost compare with the cost of financing provided by TC under the PA?
- **How can the State fund** its share of Midstream project costs?

What will be the impact of TC's exit on the State's credit rating and borrowing capacity?

- Will the State's requirement to fund Midstream costs result in increased State funding commitments?
- Will TC's exit erode the State's borrowing capacity?
- Will the State's credit rating be adversely affected by TC's exit?
- Will the long-term impact of the TC buyout be viewed as credit positive?

State Commitments Not Increased with TC Exit

Will the State's direct funding of Midstream costs result in increased State commitments?

Under the arrangement with TC, the State is already committed to pay the costs associated with the Midstream components:

- If the Project fails to complete Pre-FEED: State obligated to reimburse TC, with interest
- If the Project fails to complete FEED: Under the expected terms of the Firm Transportation Services Agreement (FTSA) with TC, the State would be obligated to reimburse TC, with interest
- If the Project fails to complete construction: Under the expected terms of the FTSA with TC, the State would be obligated to reimburse TC, with interest
- ⇒ **State assumes Midstream development and construction risks**
- If the Project achieves operations: Under the expected terms of the FTSA with TC, the State would be obligated to pay TC fixed capacity reservation charge, including repayment of TC capital through annual depreciation charge, and pass-through of Midstream costs, regardless of throughput volumes
- ⇒ **State assumes Midstream cost-overrun and throughput risks**

State Borrowing Capacity Effectively the Same with or without TC

Will TC's exit erode the State's borrowing capacity?

TC's exit will not create incremental State debt obligations; the State is already obligated to pay the Midstream costs.

- Under the PA and the anticipated terms of the FTSA, the State's payment obligations to TC require payments to TC to be "supported with the full faith and credit of the State" or a dedicated funding source acceptable to TC
- TC would be relying on the State's credit for reimbursement of its funding of Midstream costs
- FirstSouthwest has noted that the credit ratings agencies will, in all likelihood, consider the State's long-term fixed payment obligations to TC under the FTSA as analogous to a State debt obligation for purposes of analyzing State debt capacity

Example: Credit Rating Agency Treatment of “Take-or-Pay” PPAs

“Take-or-pay” power purchase agreements (PPAs) are similar to FTSA as they typically obligate the buyer to make capacity charge payments regardless of output. Such agreements are scrutinized by credit rating agencies.

MOODY'S
INVESTORS SERVICE

RATING METHODOLOGY Regulated Electric and Gas Utilities

“ [...] by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station.

[...]

When the accounting treatment of a PPA is a debt or lease equivalent (such that it is reported on the balance sheet, or disclosed as an operating lease and thus included in our adjusted debt calculation), we generally do not make adjustments to remove the PPA from the balance sheet. However, in relevant circumstances we consider making adjustments that impute a debt equivalent to PPAs that are off-balance sheet for accounting purposes.”

“PPAs are recognized qualitatively to be a future use of cash whether or not they are treated as debt-like obligations in financial ratios.”

- In prior financings, credit rating agencies have taken into account FTSA-like contracts of much lower value when assessing the credit of local governments
- The rating agencies would almost certainly scrutinize the FTSA payment commitments when assessing the State’s credit. Such scrutiny would be heightened due to the FTSA “full faith and credit” or “dedicated fund reserve” requirement

State Credit Rating not Adversely Affected by TC Exit

Will the State's credit rating be adversely affected by TC's exit?

FirstSouthwest advises that a decision to terminate the TC's participation will not, in and of itself, result in a downgrade of the State's credit rating:

- No incremental commitments by the State
- As the State's overall costs related to the Project are projected to be reduced without TC (B&V estimates a reduction of up to \$400 million per year), the termination should be viewed by the credit ratings agencies as a net positive for the State
- With or without TC, the State should anticipate a reduction in the State's credit rating during the construction period (when no gas sale revenues are being generated) absent a significant increase in revenue generated from existing sources
- Credit rating should recover once gas sale revenues become established
- TC's exit, by itself, should not result in a credit downgrade during the construction period that is greater than any downgrade if TC remained in AKLNG. The State's credit could instead be improved by the lower costs to the State as a result of TC's exit

Financial Risks to the State of Maintaining TC Funding

- Failure to reach Project FID:
 - The State would be obligated to pay TC's prior Midstream development costs and TC's internal costs, plus interest
 - A potentially substantial appropriation would need to be authorized quickly
- The State's reimbursement obligation could arise at a time of adverse credit impact on the State:
 - Lender community would be aware that the Project would not reach FID
 - the gasline Project revenues would no longer be expected to materialize
 - Consequently, the credit of the State would likely deteriorate
- **Therefore, the State could be forced, in a short timeframe, to repay TC for prior Midstream development costs in adverse credit conditions**

At what cost is the State expected to finance its share of Midstream costs?

How does such cost compare with the cost of the financing provided by TC?

Cost to the State of TC Financing

Under the TC financing arrangement, the State will pay to TC the cost of capital as follows:

- If the PA is terminated:
 - TC's costs reimbursed with interest at rate of 7.1%
 - higher rate applies if payment is not made within the required period under the PA
- If the Project proceeds to operations:
 - the State would pay a return on TC's rate base calculated on the basis of deemed weighted average cost of debt and cost of equity
 - cost of debt and return on equity adjusted for changes in the yield on 30-year Treasury bonds over time
 - debt to equity ratio: different during the construction and operating periods
 - 70:30 through the second anniversary of the in-service date and in respect of expansions and maintenance capital additions
 - 75:25 after the second anniversary of the in-service date on capital other than capital additions for expansions and maintenance

Sample TC Deemed Weighted Average Cost of Capital under the PA*

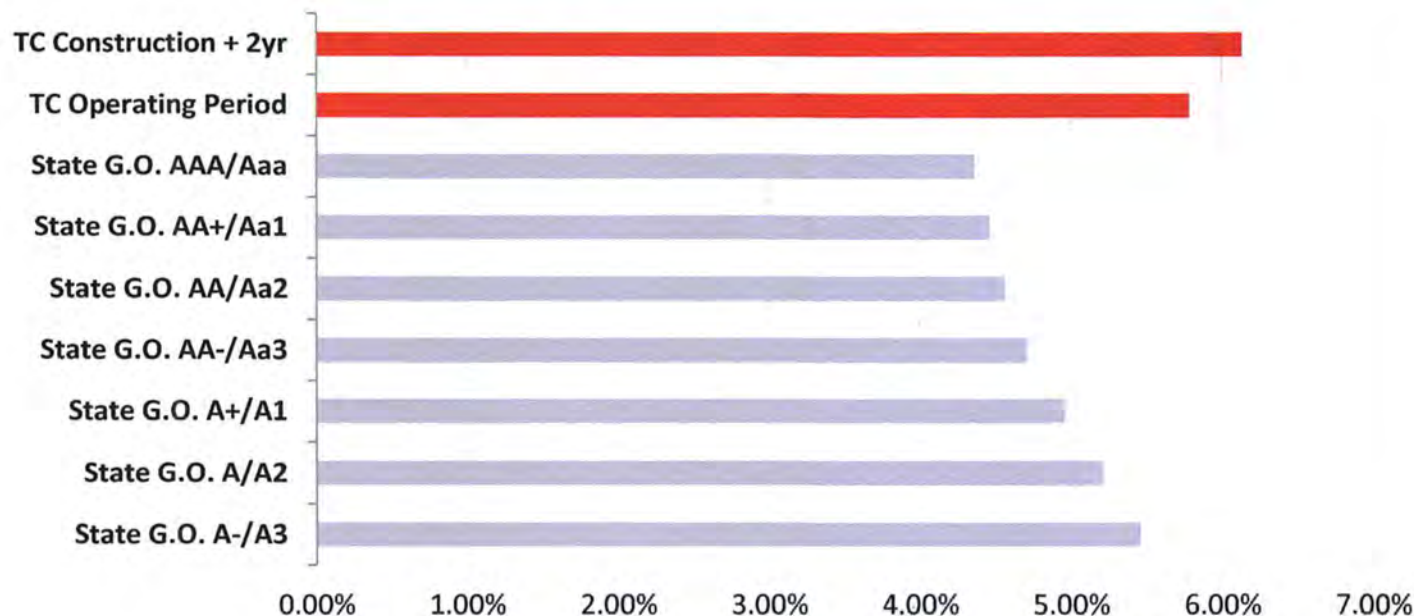
	Dec 12 th , 2013	Sep – Oct 2015
30-Year Treasury Yield	3.91%	~2.95%
TC WACC through 2 nd Year from ISD	7.10%	~6.15%
TC WACC after 2 nd Year from ISD	6.75%	~5.80%

*Actual cost of capital could be higher or lower at the time of financings.

TC Cost of Capital vs. State Debt Interest Rate

The interest rate on State debt would depend on the credit rating. The table below compares:

- TC weighted average cost of capital under the PA, calculated as of Sept 11, 2015
- Interest rates on taxable State G.O. debt, estimated by FirstSouthwest as of Sept 11, 2015



- Under all scenarios of State credit rating downgrade down to A-/A3, the State cost of debt remains below the TC cost of capital
- Note that, following a rating downgrade during the construction period, the State credit rating and cost of capital will likely recover once the Project is operational; TC cost of capital is fixed at FID for the term of the FTSA

How will the State fund its share of Midstream project costs?

Total State Funding Requirements

Shown below are the estimated funding requirements for the State's share of the project going forward*

- Includes both the Midstream components and the LNG plant
- In other words, these are the State funding requirements without TC

Pre-FEED	FEED	Construction
2014-2016	2016-2018	2019-2026
~144 million	~675 million	~13 billion

* Including payment of the TC Termination Amount and excluding prior pre-FEED appropriations and projected AGDC or agency costs.

State Funding Options

The State will have the following options to pay the TC Termination Amount and finance its share of the Project during the remainder of Pre-FEED, FEED and the construction period*:

- The Legislature could appropriate from existing State funds, e.g., the Constitutional Budget Reserve Fund (CBRF), Earnings Reserve Fund
- The Legislature could authorize the issuance of State debt
- The Legislature could authorize pursuit of project financing
- The Legislature could authorize the pursuit of funding from other sources: LNG buyers and other potential equity investors

* These are the same funding options for the LNG Plant if TC remained in the Project.

Potential Funding Sources: **State Funds**

The Legislature could appropriate from existing State funds, e.g., the CBRF, Earnings Reserve Fund

- Analysis by the DOR Treasury Division estimates:
 - CBRF could be depleted in 2018 – 2019 (exact timing depends on oil price)
 - Utilizing the CBRF to fund the TC reimbursement and the Midstream Pre-FEED and FEED costs would accelerate CBRF depletion by approximately 3-5 months
- Therefore, the CBRF could be used to fund Pre-FEED and at least a portion of FEED costs, but not construction costs
- CBRF utilizations could be repaid from the proceeds of State debt, project finance debt or other forms of State long-term funding

Potential Funding Sources: **State Debt**

The Legislature could authorize the issuance of State debt:

- Bondholders would look to the State's credit for repayment (annual appropriations would be required)
- Could be used to finance FEED and construction costs
- Could be used as long-term financing (repayment periods of 20-30 years)
- Timing implications: Authorization to issue GO debt would require voter referendum approval

Potential Funding Sources: **Project Finance**

The Legislature could authorize the pursuit of project financing:

- Lenders would look primarily to the Project-level cash flows and assets as security for repayment, rather than State funds
- Common form of debt for LNG projects
- Requires the Project commercial structure to be in place:
 - All key project agreements must be executed
 - Commercial structure must be “bankable”
- Requires that FID is reached; not available to fund FEED costs
- May require constitutional amendment to allow the pledging of LNG sales proceeds as lender collateral as the Lenders will demand that funds will be dedicated to repayment, which is currently not permitted by the State’s Constitution

As the Project’s commercial structure has not yet been agreed, it is premature to evaluate the extent to which project finance could be a viable source of funding

Potential Funding Sources: LNG Buyers and Other Equity Investors

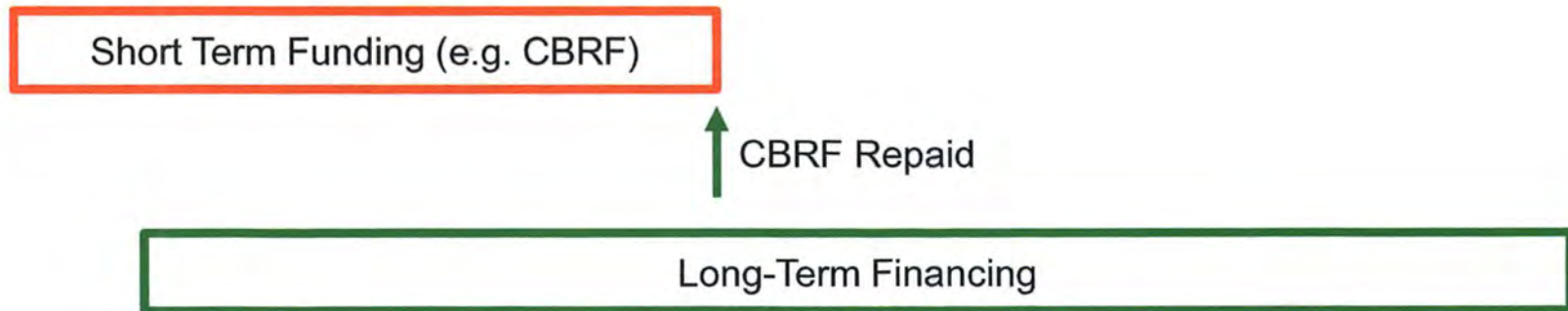
The Legislature could authorize pursuit of investment from LNG buyers or other equity investors:

- Offtakers have often acquired equity in LNG projects
- Approach by the State would need to be made in coordination with marketing plan
- New equity investors could share Project development risk
- Could provide sources of funding in the event a Producer withdraws

At this stage of the Project's development, it is premature to evaluate the extent to which LNG buyers or other equity investors could be viable sources of funding

Example Funding Scenario (For Illustrative Purposes Only)

Pre-FEED	FEED	Construction
2014-2016	2016-2018	2019-2026
~144 million	~675 million	~13 billion



Proper sequencing of the utilization of available sources of funds would ensure adequate timing to implement the funding plan approved by the Legislature:

- The CBRF could be utilized initially, with CBRF utilizations repaid from the proceeds of State debt or other forms of State long-term funding
- CBRF utilization in the near-term would provide additional time needed for the Legislature to consider proposing a GO debt offering, which would require a voter referendum approval

Conclusion

- TC's exit will require the State to fund the reimbursement of TC's Midstream development costs immediately
- TC's exit will not result in incremental financial commitments by the State
- TC's exit will have no incremental impact on the State's long-term credit rating and borrowing capacity
- TC's exit will not increase the State's cost of financing its share of Midstream costs
- The State has several options to fund its share of Midstream costs

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AKLING Debt Sizing (As of June 3, 2015)

Sizing Based on Unrestricted General Fund Revenue D/S Limit, Projected Project Revenues, a 2017 Bond Issuance, and Tax Exempt Interest Rates

Rating	% Limit	Interest Rate ⁽²⁾
Aaa/AAA	5%	3.56%
Aa1/AA+	8%	3.61%
Aa2/AA	10%	3.71%
Aa3/AA-	17%	3.81%
A1/A+	17%	3.91%
A2/A	20%	4.01%

*** Preliminary - For Discussion Purposes Only ***

Year	Current Unrestricted General Fund Revenue	Project Revenue Projections ⁽³⁾	Total Revenue	Existing D/S ⁽⁴⁾	Aaa/AAA	Aaa/AAA	Aa1/AA+	Aa1/AA+	Aa2/AA	Aa2/AA	Aa3/AA-	Aa3/AA-	A1/A+	A1/A+	A2/A	A2/A
	Forecast (1)				D/S Limit	Capacity	D/S Limit	Capacity	D/S Limit	Capacity	D/S Limit	Capacity	D/S Limit	Capacity	D/S Limit	Capacity
2016	2,198,200,000	(9,796,423)	2,188,403,577	65,200,000												
2017	3,174,900,000	(9,916,177)	3,164,983,823	63,200,000												
2018	3,240,600,000	(9,870,389)	3,230,729,611	63,100,000	161,536,481	98,436,481	258,458,369	195,358,369	323,072,961	259,972,961	387,687,553	324,587,553	549,224,034	486,124,034	646,145,922	583,045,922
2019	3,788,300,000	(9,930,049)	3,778,369,951	63,000,000	188,918,498	125,918,498	302,269,596	239,269,596	377,836,995	314,836,995	453,404,394	390,404,394	642,322,892	579,322,892	755,673,990	692,673,990
2020	4,535,200,000	88,944,716	4,624,144,716	51,900,000	231,207,236	179,307,236	369,931,577	318,031,577	462,414,472	410,514,472	554,897,366	502,997,366	786,104,602	734,204,602	924,828,943	872,928,943
2021	4,435,100,000	152,154,413	4,587,254,413	51,900,000	229,362,721	177,462,721	366,980,353	315,080,353	458,725,441	406,825,441	550,470,530	498,570,530	779,833,250	727,933,250	917,450,883	865,550,883
2022	4,260,700,000	214,197,985	4,474,897,985	41,700,000	223,744,899	182,044,899	357,991,839	316,291,839	447,489,799	405,789,799	536,987,758	495,287,758	760,732,657	719,032,657	894,979,597	853,279,597
2023	4,265,900,000	227,138,462	4,493,038,462	41,800,000	224,651,923	182,851,923	359,443,077	317,643,077	449,303,846	407,503,846	539,164,615	497,364,615	763,816,539	722,016,539	898,607,692	856,807,692
2024	4,218,000,000	214,783,596	4,432,783,596	44,700,000	221,639,180	176,939,180	354,622,688	309,922,688	443,278,360	398,578,360	531,934,032	487,234,032	753,573,211	708,873,211	886,556,719	841,856,719
2025	4,218,000,000	188,048,864	4,406,048,864	37,300,000	220,302,443	183,002,443	352,483,909	315,183,909	440,604,886	403,304,886	528,725,864	491,425,864	749,028,307	711,728,307	881,209,773	843,909,773
2026	4,218,000,000	4,078,021,948	8,296,021,948	17,800,000	414,801,097	397,001,097	663,681,756	645,881,756	829,602,195	811,802,195	995,522,634	977,722,634	1,410,323,731	1,392,523,731	1,659,204,390	1,641,404,390
2027	4,218,000,000	4,032,615,028	8,250,615,028	36,300,000	412,530,751	376,230,751	660,049,202	623,749,202	825,061,503	788,761,503	990,073,803	953,773,803	1,402,604,555	1,366,304,555	1,650,123,006	1,613,823,006
2028	4,218,000,000	4,134,820,796	8,352,820,796	36,300,000	417,641,040	381,341,040	668,225,664	631,925,664	835,282,080	798,982,080	1,002,338,496	966,038,496	1,419,979,535	1,383,679,535	1,670,564,159	1,634,264,159
2029	4,218,000,000	4,235,126,170	8,453,126,170	36,200,000	422,656,309	386,456,309	676,250,094	640,050,094	845,312,617	809,112,617	1,014,375,140	978,175,140	1,437,031,449	1,400,831,449	1,690,625,234	1,654,425,234
2030	4,218,000,000	4,323,981,290	8,541,981,290	36,100,000	427,099,065	390,999,065	683,358,503	647,258,503	854,198,129	818,098,129	1,025,037,755	988,937,755	1,452,136,819	1,416,036,819	1,708,396,258	1,672,296,258
2031	4,218,000,000	4,397,974,996	8,615,974,996	23,600,000	430,798,750	407,198,750	689,278,000	665,678,000	861,597,500	837,997,500	1,033,917,000	1,010,317,000	1,464,715,749	1,441,115,749	1,723,194,999	1,699,594,999
2032	4,218,000,000	4,462,409,115	8,680,409,115	23,500,000	434,020,456	410,520,456	694,432,729	670,932,729	868,040,912	844,540,912	1,041,649,094	1,018,149,094	1,475,669,550	1,452,169,550	1,736,081,823	1,712,581,823
2033	4,218,000,000	4,525,199,772	8,743,199,772	23,500,000	437,159,989	413,659,989	699,455,982	675,955,982	874,319,977	850,819,977	1,049,183,973	1,025,683,973	1,486,343,961	1,462,843,961	1,748,639,954	1,725,139,954
2034	4,218,000,000	4,587,095,153	8,805,095,153	23,500,000	440,254,758	416,754,758	704,407,612	680,907,612	880,509,515	857,009,515	1,056,611,418	1,033,111,418	1,496,866,176	1,473,366,176	1,761,019,031	1,737,519,031
2035	4,218,000,000	4,646,770,326	8,864,770,326	100,000	443,238,516	443,138,516	709,181,626	709,081,626	886,477,033	886,377,033	1,063,772,439	1,063,672,439	1,507,010,955	1,506,910,955	1,772,854,065	1,772,754,065
2036	4,218,000,000	4,717,150,056	8,935,150,056	100,000	446,757,503	446,657,503	714,812,004	714,712,004	893,515,006	893,415,006	1,072,218,007	1,072,118,007	1,518,975,510	1,518,875,510	1,787,030,011	1,786,930,011
2037	4,218,000,000	4,857,447,607	9,075,447,607	100,000	453,772,380	453,672,380	726,035,809	725,935,809	907,544,761	907,444,761	1,089,053,713	1,088,953,713	1,542,826,093	1,542,726,093	1,815,089,521	1,814,989,521
2038	4,218,000,000	4,987,830,118	9,205,830,118	12,000,000	460,291,506	448,291,506	736,466,409	724,466,409	920,583,012	908,583,012	1,104,699,614	1,092,699,614	1,564,991,120	1,552,991,120	1,841,166,024	1,829,166,024

Footnotes

- 1 Unrestricted General Fund Revenue per Spring 2015 Revenue Source Book, April 2015, Table A-4b (2024 forecast is used through 2038)
- 2 Estimated Tax Exempt Interest Cost as of June 3, 2015
- 3 Project revenue projections net of marketing organization costs and midstream operating costs supplied by Black & Veatch and discussed with Lazard
- 4 Existing State General Obligation Debt Service plus Lease/Purchase Debt Service per State of Alaska Department of Revenue, Public Debt Report 2014-2015, January 2015, Table 4.9

AKLNG Debt Sizing
Sizing Based on Unrestricted General Fund Revenue D/S Limit, a 2017 Bond Issuance, and Tax Exempt Interest Rates

*** Preliminary - For Discussion Purposes Only ***

Year	Aaa/AAA			Aa1/AA+			Aa2/AA			Aa3/AA-			A1/A+			A2/A		
	Principal	Interest	Total	Principal	Interest	Total	Principal	Interest	Total	Principal	Interest	Total	Principal	Interest	Total	Principal	Interest	Total
	Par Amount Issued 4,287,700,000 Transaction Costs (.6% of Par) 25,726,200 Net Proceeds 4,261,973,800			Par Amount Issued 7,127,860,000 Transaction Costs (.6% of Par) 42,767,160 Net Proceeds 7,085,092,840			Par Amount Issued 8,935,635,000 Transaction Costs (.6% of Par) 53,613,810 Net Proceeds 8,882,021,190			Par Amount Issued 10,702,950,000 Transaction Costs (.6% of Par) 64,217,700 Net Proceeds 10,638,732,300			Par Amount Issued 15,202,120,000 Transaction Costs (.6% of Par) 91,212,720 Net Proceeds 15,110,907,280			Par Amount Issued 17,774,540,000 Transaction Costs (.6% of Par) 106,647,240 Net Proceeds 17,667,892,760		
2016																		
2017																		
2018	(54,210,000)	152,642,120	98,432,120	(61,960,000)	257,315,746	195,355,746	(71,540,000)	331,512,059	259,972,059	(83,200,000)	407,782,395	324,582,395	(108,280,000)	594,402,892	486,122,892	(129,715,000)	712,759,054	583,044,054
2019	(28,655,000)	154,571,996	125,916,996	(20,285,000)	259,552,502	239,267,502	(19,330,000)	334,166,193	314,836,193	(20,550,000)	410,952,315	390,402,315	(19,315,000)	598,636,640	579,321,640	(25,290,000)	717,960,626	692,670,626
2020	23,710,000	155,592,114	179,302,114	57,745,000	260,284,791	318,029,791	75,630,000	334,883,336	410,513,336	91,260,000	411,735,270	502,995,270	134,810,000	599,391,857	734,201,857	153,950,000	718,974,755	872,924,755
2021	22,710,000	154,748,038	177,458,038	56,880,000	258,200,196	315,080,196	74,745,000	332,077,463	406,822,463	90,310,000	408,258,264	498,568,264	133,810,000	594,120,786	727,930,786	152,745,000	712,801,360	865,546,360
2022	28,105,000	153,939,562	182,044,562	60,145,000	256,146,828	316,291,828	76,485,000	329,304,423	405,789,423	90,470,000	404,817,453	495,287,453	130,140,000	588,888,815	719,028,815	146,600,000	706,676,285	853,276,285
2023	29,910,000	152,939,024	182,849,024	63,665,000	253,975,594	317,640,594	81,035,000	326,466,830	407,501,830	95,990,000	401,370,546	497,360,546	138,215,000	583,800,341	722,015,341	156,010,000	700,797,625	856,807,625
2024	25,060,000	151,874,228	176,934,228	58,245,000	251,677,287	309,922,287	75,115,000	323,460,431	398,575,431	89,520,000	397,713,327	487,233,327	130,475,000	578,396,134	708,871,134	147,315,000	694,541,624	841,856,624
2025	32,020,000	150,982,092	183,002,092	65,605,000	249,574,643	315,179,643	82,630,000	320,673,665	403,303,665	97,120,000	394,302,615	491,422,615	138,430,000	573,294,562	711,724,562	155,275,000	688,634,293	843,909,293
2026	247,155,000	149,842,180	396,997,180	398,675,000	247,206,302	645,881,302	494,190,000	317,608,092	811,798,092	587,120,000	390,602,343	977,722,343	824,640,000	567,881,949	1,392,521,949	958,995,000	682,407,765	1,641,402,765
2027	235,185,000	141,043,462	376,228,462	390,930,000	232,814,135	623,744,135	489,485,000	299,273,643	788,758,643	585,540,000	368,233,071	953,773,071	830,665,000	535,638,525	1,366,303,525	969,870,000	643,952,066	1,613,822,066
2028	248,665,000	132,670,876	381,335,876	413,220,000	218,701,562	631,921,562	517,865,000	281,113,749	798,978,749	620,110,000	345,923,997	966,033,997	880,520,000	503,159,523	1,383,679,523	1,029,200,000	605,060,279	1,634,260,279
2029	262,635,000	123,818,402	386,453,402	436,265,000	203,784,320	640,049,320	547,210,000	261,900,958	809,110,958	655,875,000	322,297,806	978,172,806	932,100,000	468,731,191	1,400,831,191	1,090,635,000	563,789,359	1,654,424,359
2030	276,530,000	114,468,596	390,998,596	459,220,000	188,035,153	647,255,153	576,495,000	241,599,467	818,094,467	691,625,000	297,308,969	988,933,969	983,750,000	432,286,081	1,416,036,081	1,152,240,000	520,054,895	1,672,294,895
2031	302,570,000	104,624,128	407,194,128	494,220,000	171,457,311	665,677,311	617,785,000	220,211,502	837,996,502	739,355,000	270,958,056	1,010,313,056	1,047,290,000	393,821,456	1,441,111,456	1,225,740,000	473,850,071	1,699,590,071
2032	316,665,000	93,852,636	410,517,636	517,315,000	153,615,969	670,930,969	647,245,000	197,291,679	844,536,679	775,360,000	242,788,631	1,018,148,631	1,099,295,000	352,872,417	1,452,167,417	1,287,880,000	424,697,897	1,712,577,897
2033	331,080,000	82,579,362	413,659,362	541,015,000	134,940,898	675,955,898	677,540,000	173,278,889	850,818,889	812,435,000	213,247,415	1,025,682,415	1,152,950,000	309,889,983	1,462,839,983	1,352,085,000	373,053,909	1,725,138,909
2034	345,960,000	70,792,914	416,752,914	565,495,000	115,410,256	680,905,256	708,865,000	148,142,155	857,007,155	850,815,000	182,293,641	1,033,108,641	1,208,555,000	264,809,638	1,473,364,638	1,418,680,000	318,835,301	1,737,515,301
2035	384,660,000	58,476,738	443,136,738	614,085,000	94,995,887	709,080,887	764,530,000	121,843,264	886,373,264	913,790,000	149,877,590	1,063,667,590	1,289,355,000	217,555,137	1,506,910,137	1,510,905,000	261,946,233	1,772,851,233
2036	401,870,000	44,782,842	446,652,842	641,880,000	72,827,418	714,707,418	799,935,000	93,479,201	893,414,201	957,055,000	115,062,191	1,072,117,191	1,351,730,000	167,141,357	1,518,871,357	1,585,570,000	201,358,942	1,786,928,942
2037	423,195,000	30,476,270	453,671,270	676,280,000	49,655,550	725,935,550	843,640,000	63,801,612	907,441,612	1,010,355,000	78,598,395	1,088,953,395	1,428,435,000	114,288,714	1,542,723,714	1,677,210,000	137,777,585	1,814,987,585
2038	432,880,000	15,410,528	448,290,528	699,220,000	25,241,842	724,461,842	876,080,000	32,502,568	908,582,568	1,052,595,000	40,103,870	1,092,698,870	1,494,550,000	58,436,905	1,552,986,905	1,758,640,000	70,521,464	1,829,161,464
	4,287,700,000	2,390,128,108	6,677,828,108	7,127,860,000	3,955,414,186	11,083,274,186	8,935,635,000	5,084,591,173	14,020,226,173	10,702,950,000	6,254,228,157	16,957,178,157	15,202,120,000	9,097,444,898	24,299,564,898	17,774,540,000	10,930,451,384	28,704,991,384

Shortfall that could possibly be corrected with an appropriation

20 JANUARY 2015

AKLNG PROJECT—LAZARD INTERIM REPORT



LAZARD

Disclaimer

This document has been prepared by Lazard Frères & Co. LLC (“Lazard”) based upon information supplied by the State of Alaska (the “State”) and its representatives and advisors, as well as publicly available information. Portions of the information herein may be based upon certain statements, estimates and forecasts provided by the State with respect to the historical or anticipated future performance of the State. We have relied upon the accuracy and completeness of all the foregoing information, and have not assumed any responsibility for any independent verification of such information. With respect to financial forecasts, we have assumed that they have been reasonably prepared on bases reflecting the best currently available estimates and judgments as to the applicable future financial performance. We assume no responsibility for and express no view as to such forecasts or the assumptions on which they are based. The information set forth herein is based upon economic, monetary, market and other conditions, and the information made available to us as of the date hereof, unless indicated otherwise. Lazard does not have any obligation to update or otherwise revise this document. Lazard is not providing and is not responsible for any tax, accounting, actuarial, legal or other specialist advice. These materials are also summary in nature and do not purport to include all of the information that should be evaluated in considering alternatives for the State. Lazard is acting as investment banker to the State and any advice, recommendations, information or work product provided by Lazard is for the sole use of the State. This document, and any advice, recommendations, information or work product provided by Lazard is not intended for the benefit of any third party and may not be relied upon by any third party.

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I Introduction

I. Introduction

The State, pursuant to Senate Bill 138 (“SB 138”), has engaged Lazard to provide assistance in reviewing and analyzing various financing options for the State’s interest in the Alaska LNG Project (the “Project” or “AKLNG Project”). This Interim Report provides a detailed description of the Project, an overview of the State’s finances and an introduction to various financing considerations for the Project in advance of the Final Report, to be delivered in Fall 2015,¹ which will provide a detailed description of a range of financing alternatives, analyze the benefits and considerations of these alternatives and deliver specific financing recommendations to the State.

A. Legislative Origins of Lazard AKLNG Report

SB 138, signed into law on May 8, 2014, calls for the “development of a plan” for Alaska “municipalities, regional corporations and residents to participate in the ownership of a North Slope natural gas pipeline.”² Pursuant to this legislation, the Alaska Department of Revenue Commissioner’s Office solicited proposals from qualified firms to serve as a “financial consultant on the State’s participation in the continued development of a liquefied natural gas project from Alaska’s North Slope.” The goals of the engagement were to include “the identification of financing options for State ownership and participation in a North Slope natural gas project, [a] description of the risks associated with each option and the effect of each option on the State’s debt capacity and the State’s long-term debt rating” as well as “recommendations as to how to allow municipalities, regional corporations and individuals of the State an opportunity to participate as a co-owner in the project.”³ At the conclusion of the RFP process, the State selected Lazard to serve as its financial consultant.

¹ Prior to any Front-End Engineering and Design (“FEED”) decision.

² SB 138 Sec. 76(a) – (c).

³ State of Alaska Department of Revenue, Request for Proposal (“RFP”) 2015-0400-2600: AKLNG Financial Consultant.

B. Role of Lazard

As a financial consultant, Lazard will analyze⁴ and report on potential financing alternatives for State participation in the AKLNG Project (including potential direct participation on behalf of residents, municipalities and/or regional corporations). As part of its mandate, Lazard will:

- Formulate a range of potential financing alternatives and evaluative criteria
 - Analyze, for example, the key potential risks, potential impact on the State's debt capacity and long-term debt rating, potential for participation of various Alaska stakeholders and tax implications associated with each alternative
- Collaborate with stakeholders, including the State, Alaska Gasline Development Corporation ("AGDC"), ExxonMobil ("Exxon"), ConocoPhillips ("Conoco"), BP, TransCanada Corporation ("TransCanada"), State advisors and other constituents
- Develop specific recommendations designed to maximize benefits to the State
- Meet Project deliverable requirements:
 - Delivery of Interim Report by January 20, 2015
 - Delivery of Final Report in Fall 2015⁵

⁴ In coordination with the State Department of Revenue and other State advisors, including FirstSouthwest, Black & Veatch and Greenberg Traurig.

⁵ Prior to any FEED decision.

II Executive Summary

II. Executive Summary

EXECUTIVE SUMMARY

LNG BACKGROUND AND OVERVIEW	GLOBAL LNG OVERVIEW	<ul style="list-style-type: none"> ■ Global market dynamics seemingly support the development of new liquefied natural gas (“LNG”) export projects⁶ <ul style="list-style-type: none"> ■ Over the past 20 years, LNG has become a significant global energy source with trade volumes that have more than quadrupled over that period ■ LNG demand is highly concentrated in Pacific Rim countries and is expected by industry experts to increase in the coming years, particularly in China, Japan and Indonesia, where the greatest number of new LNG receiving terminals are being developed ■ The global LNG market involves an ecosystem of participants, including governments, producers, construction companies, shippers and operators, among others
	OVERVIEW OF ALASKA’S NATURAL RESOURCES AND LNG POSITIONING	<ul style="list-style-type: none"> ■ Significant natural gas resources exist in Alaska, particularly in the North Slope region <ul style="list-style-type: none"> ■ Since the 1970s, numerous stakeholders, including State and Federal government administrations, and private sector entities, have attempted, without success, to develop these natural gas resources in Alaska’s North Slope ■ The supply of North Slope natural gas potentially represents a valuable investment opportunity for the State and its residents <ul style="list-style-type: none"> ■ In-State natural gas development could potentially support Alaska’s budget, particularly in the coming years, when oil production is expected to decline ■ Alaska’s natural gas resources are significant and could potentially support the State’s position as a top-five global LNG exporter ■ Alaska holds certain advantages in the development of a large-scale LNG project, including: <ul style="list-style-type: none"> ■ A highly stable political environment as compared to countries that are the site of large-scale development projects (e.g., Nigeria, Russia, etc.) ■ Colder temperatures, which make the liquefaction process more efficient ■ Higher heat content natural gas, which makes the commodity more valuable ■ Access to Pacific Rim LNG markets, which constitute the majority of existing LNG demand and projected demand growth
AKLNG PROJECT OVERVIEW		<ul style="list-style-type: none"> ■ The Project involves the coordinated efforts of oil producers Exxon, BP and Conoco, together with TransCanada and the State <ul style="list-style-type: none"> ■ In addition, a number of Alaska entities and constituents may participate in or stand to benefit from the Project, including State residents, Alaska municipalities, Alaska native corporations and various other Alaska entities ■ The Project primarily consists of three components: a gas treatment plant (“GTP”), a gas pipeline (“Pipeline”) and a liquefaction plant (“LNG Plant”) <ul style="list-style-type: none"> ■ The State has entered into an agreement with TransCanada to help finance the State’s portion of the GTP and the Pipeline ■ Project sponsors include Exxon, BP, Conoco and the State, each with a currently contemplated 25% ownership stake⁷

⁶ Current commodity pricing environment (including historically-low oil prices) has the potential to negatively impact LNG project development. In preparation for the delivery of the Final Report in Fall 2015, Lazard will continue to monitor global LNG market dynamics.

⁷ 25% ownership figure is illustrative. Ultimate Project ownership percentage will depend, for example, on each entity’s share of Project gas, among other factors, and may vary from this amount.

AKLNG PROJECT OVERVIEW
(CONT'D)

- Currently in its Pre-FEED phase, the Project would involve approximately 2 – 4 years of additional planning followed by 5 – 6 years of construction
 - The final investment decision (“FID”) for the Project is estimated to occur in 2018/2019 (the vast majority of the capital investment would occur after that point)
- Current estimated Project cost: \$45 – \$65 billion⁸
 - Pre-FEED: \$400 – \$500 million
 - FEED: \$1.5 – \$2.1 billion
 - Engineering, Procurement and Construction (“EPC”): \$43.2 – \$62.3 billion

STATE OF ALASKA FINANCIAL
OVERVIEW

- The State’s present-day reliance on oil revenues, combined with historically-low oil prices and declining oil production forecasts, suggest that a new revenue source could help Alaska maintain its strong financial position⁹
 - In FY 2014, oil revenues accounted for 88% of the State’s unrestricted revenue (i.e., revenue used to fund the State’s general expenses)
 - At its peak, Alaska’s North Slope oil production constituted 26% of total U.S. production; however, production has declined consistently since the 1980s and is projected by the State to decrease materially over the next 10 years due to diminished oil reserves
 - Historically-low oil prices are placing further pressure on the State’s budget
 - Current forecasts show the State depleting its \$15 billion budget reserve funds by 2022 – 2023
- In addition to revenues generated by oil production activity in the State, Alaska’s financial health depends upon the performance of the State’s various investment funds (e.g., Permanent Fund, etc.)
- In light of the State’s current debt levels, and other factors, the State enjoys a “triple-A” rating from all three major credit rating agencies; however, additional capacity to issue debt may exist, subject to potential ratings agency downgrades¹⁰
 - State maintains current “Aaa” rating: \$2.7 billion of incremental debt capacity
 - State is downgraded to “Aa1” rating: \$4.7 billion of incremental debt capacity
 - State is downgraded to “Aa2” rating: \$5.9 billion of incremental debt capacity

SUMMARY PRELIMINARY
FINANCING CONSIDERATIONS

- The State should consider a variety of factors as it evaluates how to finance its portion of the Project, including the size of investment, the source of funds, the debt/equity capitalization relationship, how it structures its investment in the Project and the specific terms and conditions of the overall investment arrangement
 - The size of the State’s Project investment requirement depends on the participation of TransCanada as a partner, the effects of further developments with the Project and the outcome of future negotiations
 - The State has a variety of sources potentially available to fund its portion of the upfront investment in the Project, including funds from the State (e.g., Permanent Fund earnings, via allocation by the Legislature), Alaska municipalities/regional corporations and residents, and external sources
 - In addition to evaluating potential funding sources, the State will need to evaluate the optimal financing structure and terms/conditions under which those funds could be invested in the Project; in general, the State could structure Project investments as debt, equity or a combination thereof

⁸ Here and throughout this Report, Project costs are shown in 2012 dollars, unless otherwise noted. Alaska’s portion of the estimated Project cost is currently projected to range from \$7.0 to \$13.7 billion and is subject to change, depending on further negotiation.

⁹ As noted herein, sustained low oil prices also, on balance, negatively impact LNG and its position in the global energy markets where LNG is competing with oil.

¹⁰ FirstSouthwest analysis.

OVERVIEW OF
POTENTIAL
STRUCTURING
ALTERNATIVES

STATE
PROJECT
COMPANY

- The State Project Company, a hypothetical financing vehicle for the Project, would be the entity to invest in the Project, receive Project revenues, service Project-related debt payments, etc.¹¹
- Investments in the State Project Company from various funding sources may be structured, broadly speaking, as debt, equity or a combination thereof

DEBT

- Recourse Debt
 - Debt that has full recourse to the State and potentially significant impact on the State's credit rating
 - Relatively less expensive than other debt alternatives
 - Allows the State to maintain its undiluted ownership of and control interest in the State Project Company
- Limited-recourse Debt
 - Debt that has only limited recourse to the State and potentially moderate impact on the State's credit rating
 - "Middle of the road" in terms of cost vs. other debt alternatives; still less expensive than equity alternatives
 - Allows the State to maintain its undiluted ownership of and control interest in the State Project Company
- Non-recourse Debt (e.g., project financing)
 - Debt that has no recourse to the State and potentially minimal impact on the State's credit rating
 - More expensive than other "straight" debt alternatives; less expensive than equity alternatives
 - Allows the State to maintain its undiluted ownership of and control interest in the State Project Company
- Hybrid Securities (e.g., Convertible Debt)
 - A type of security that blends the characteristics of debt and equity, thereby producing a more expensive financing choice than other debt alternatives, but a less expensive financing choice than equity alternatives
 - Well-developed area of the capital markets, but more complex than other financing alternatives; in some cases, market for investors can be relatively limited

EQUITY

- Common Equity
 - Represents basic ownership interest in the State Project Company
 - More expensive than debt alternatives; however, may facilitate optimal capital structure and structuring approaches, which could minimize control and other effects of equity issuances
 - The sale of equity to third parties could result in the dilution of the State's ownership in and control of the State Project Company
- Preferred Equity
 - Debt-like equity security that would allow the State Project Company to structure its financing in a way that likely does not impact the State's credit rating
 - More expensive than debt alternatives; however, preferred stock is less expensive than common equity and potentially preserves for the State operational flexibility and control/governance rights
 - Allows the State to maintain its undiluted ownership in and control of the State Project Company
- Warrants
 - Allow the State Project Company to raise some level of capital while deferring any of the potential ownership/control dilution associated with common equity
 - Potentially preferable to common equity, depending on exercise price, scope and benefits to other financing efforts

¹¹ A more detailed description of the State Project Company, and other related matters, is presented below in Section VII.

PRELIMINARY SELECTED
EVALUATIVE CRITERIA

- Lazard's Final Report will provide specific analysis and recommendations with respect to the various funding sources and financing alternatives,¹² taking into account a number of key evaluative criteria, including the following:
 - Potential impact on the State's debt capacity/opportunity cost
 - The State has a finite capacity to issue debt, and to the extent that it wishes to issue debt for other purposes, this capacity may be limited depending on how much debt is issued for the Project
 - The State's funds (e.g., the Permanent Fund) invest in a variety of different securities; diverting dollars to invest in the Project means that these dollars are not available for other fund investments
 - Potential impact on the State's credit rating
 - Increasing the amount of State debt could result in rating agency downgrades
 - A decrease in the State's credit rating could constrain future efforts by the State to access the capital markets and could raise the State's overall cost of debt
 - Key risks
 - Potential for default, financial distress and loss of operational flexibility for debt structuring alternatives
 - Potential for the State to lose all or a portion of its investment in the Project
 - Potential for lenders to have recourse to State assets
 - Cost
 - Interest rate for funding alternatives and debt structuring
 - Required return for funding alternatives and equity structuring
 - Issuance, structuring and other fees (e.g., payments to underwriters, lawyers, financial advisors, etc.)
 - Execution flexibility/feasibility
 - Certain types of financing structures are easier to implement than others, including with respect to facilitating investment participation by State residents, corporations and municipalities
 - Certain types of funding sources are more accessible than others
 - Certain provisions (e.g., debt covenants) can potentially be restrictive and limit the State's flexibility
 - Alignment of interests among key parties
 - Certain financing alternatives and/or funding sources may introduce Project misalignment, conflicts of interest or other forms of dysfunction for sponsors

RECOMMENDED NEXT STEPS

In preparation for the delivery of the Final Report in Fall 2015, Lazard will focus on the following areas of analysis and interaction, among others:

- Participation in State legislative session during Spring 2015
- Continued monitoring of global LNG market dynamics
 - Update of Black & Veatch Model to reflect, among other items, current commodity pricing environment¹³
- Continued monitoring of Project developments (e.g., offtake agreements, partnership agreement, etc.) and potential impacts on analysis of financing alternatives

¹² Inclusive of any potential terms and conditions.

¹³ Black & Veatch Cash Flows Model ("Black & Veatch Model"), dated February 2014, contains forecasts of Project cash flows analyzed herein.

RECOMMENDED NEXT STEPS
(CONT'D)

- Further analysis of potential sources of funds
 - Interaction with various State and external fund providers to gauge interest in Project participation
 - Identification of preferred sources of funds via analysis and interaction with key stakeholders, including the Alaska Legislature
- Further analysis of potential structuring alternatives
 - Identification of preferred structuring alternatives via analysis and interaction with key stakeholders, including the Alaska Legislature
- Further refinement of evaluative criteria
- Formation of potential financing alternatives (i.e., combinations of sources of funds and structuring alternatives)
- Analysis of implementation issues associated with potential financing alternatives
 - Legislative
 - Regulatory
 - Legal
 - Execution
 - Other
- Assessment of financing alternatives against evaluative criteria
- Identification of optimal financing alternatives via iterative process (i.e., in consideration of evaluative criteria, implementation issues and other factors)
- Drafting of Final Report
 - Continued iteration and interaction with the Department of Revenue and State advisors

III LNG Background and Overview

III. LNG Background and Overview

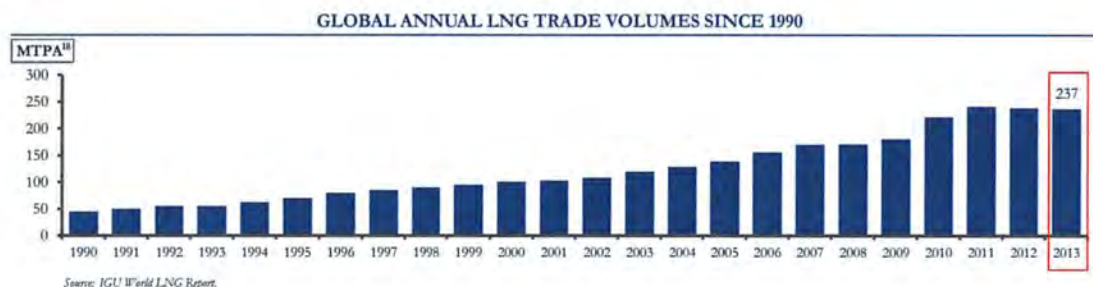
The AKLNG Project results from a long history of efforts to develop Alaska’s natural gas resources. Since the 1970s, State and Federal administrations, as well as various private sector stakeholders, have attempted to monetize North Slope natural gas reserves without success. However, the global LNG market has evolved considerably since those early efforts. The current AKLNG Project benefits from strong global LNG demand dynamics, competitive geographic advantages, alignment of interests among key Project stakeholders and a more advanced understanding of the costs and benefits associated with the Project.

A. Global LNG Overview

1. LNG Market Overview

LNG is a form of natural gas that has been condensed via extreme cooling. Unlike oil, natural gas is not liquid at room temperature, and must be cooled to allow for cost-effective shipment, via a process known as liquefaction. Once cooled (at -259°F or below), natural gas is 600 times denser than it is at ambient temperatures, allowing for shipment over long distances, and enabling delivery to distant geographies.¹⁴

Over the past twenty years, LNG has transformed from a regional energy source to one with worldwide economic and political implications. Various factors have affected the surge in demand for LNG, including both political and market forces. For example, increasing concern around the environmental impact of traditional energy sources has prompted attention to natural gas as the cleanest-burning fossil fuel (it produces 60% – 90% less hydrocarbon emissions than oil).¹⁵ Certain markets and electricity providers that have sought methods to minimize the impacts of supply/demand volatility have found that the long-term fixed contract model of LNG provides a logical solution.¹⁶ In other markets, where remote geography and/or a lack of natural resources constrain the supply of energy assets, LNG has proved to be a cost-effective energy source.¹⁷ The role of LNG in the global marketplace has steadily increased since 1990, as illustrated in the chart below.



¹⁴ “Fall 2013 Revenue Sources Book,” The State of Alaska, 2013 (“Fall 2013 Revenue Sources Book”).

¹⁵ “LNG – Global Challenges & Opportunities and Imperatives in India,” The Boston Consulting Group, 2014 (“BCG Report”).

¹⁶ “Global LNG,” EY, 2014 (“EY Report”).

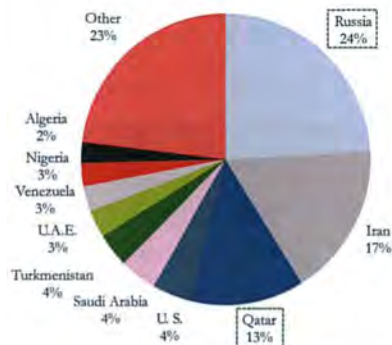
¹⁷ “World LNG Report,” International Gas Union, 2014 (“IGU World LNG Report”).

¹⁸ Metric tons per annum (“MTPA”).

III. LNG BACKGROUND AND OVERVIEW

Global LNG supply is highly concentrated, with the top five producing countries providing 67% of the total global supply of 237 MTPA.¹⁹ Both supply and demand dimensions shape this high concentration. While countries with plentiful natural gas reserves typically produce greater LNG exports, this is not always the case, as a result of several factors. For example, high fixed costs associated with upstream development and liquefaction can inhibit development. Also, some countries rich in natural gas reserves, such as the U.S. and Russia, have significant domestic demand, which limits exports.²⁰ This relationship is illustrated in the charts below; while Russia has the largest global proved reserves of natural gas at 24% of the total, it accounted for only 5% of global LNG exports in 2013. Conversely, while Qatar accounts for only 13% of global proved reserves, it produced the largest share of global LNG exports in 2013 at 33% of the total.

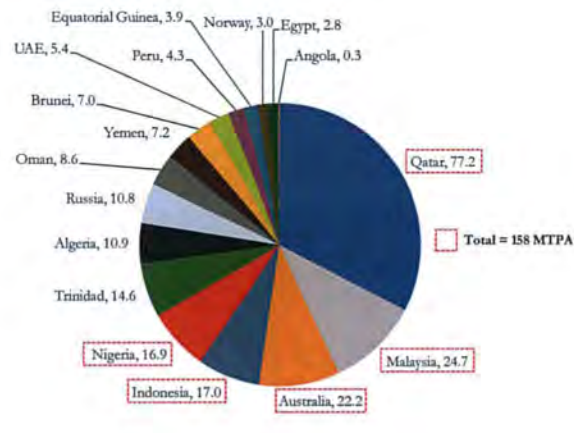
2013 NATURAL GAS PROVED RESERVES
BY COUNTRY (Tcf²¹)



Total Proved Reserves: 6,991 Tcf

Source: U.S. Energy Information Administration ("EIA").

2013 LNG EXPORTS
BY COUNTRY (MTPA)



Total LNG Exports: 237 MTPA

Source: IGU World LNG Report.

Today's LNG supply landscape is still dominated by the first movers in natural gas liquefaction. Qatar now controls a significant share of global LNG production, largely as a result of a rapid series of developments in the mid-2000s,²² but other top exporting countries have been significant players in LNG for several decades. Indonesia began exporting LNG in the mid-1970s,²³ and Malaysia and Australia emerged as major exporters in the 1980s.²⁴ Existing suppliers continue to increase capacity, however, and the supply landscape is expected to diversify over the next decade as many other nations and geographies (e.g., Venezuela, North Africa, etc.) increase their capacity despite

¹⁹ Based on 2013 figures.

²⁰ "An Overview of the World LNG Market and Canada's Potential for Exports of LNG," Canadian Association of Petroleum Producers, 2014.

²¹ Trillion cubic feet ("Tcf").

²² EY Report.

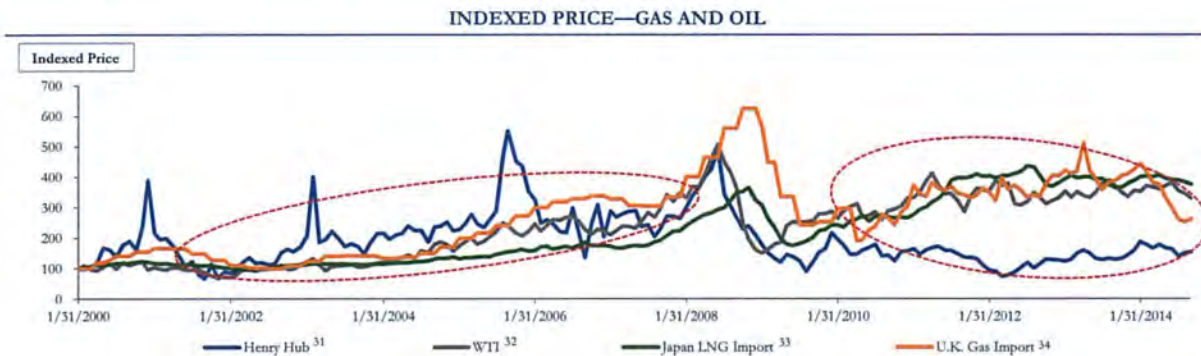
²³ "Significant Events in the History of LNG," Energy.gov, 2004.

²⁴ "Fifty Years of Global LNG," Trafigura, 2014.

significant geopolitical and financial barriers. As a result of this increase in LNG supply, LNG is expected to constitute a larger proportion of total natural gas production going forward.²⁵

Global LNG demand is also highly concentrated, with Asian markets—particularly Japan, South Korea and China—being the largest importers. The reliance of these countries on LNG is driven by factors such as remote geography, lack of domestic natural resources, and, in the case of Japan and South Korea, the retirement or decommissioning of baseload nuclear power plants. These long-term trends lead to relative price stability of LNG in these markets. By contrast, newer LNG import markets such as India, the Middle East, Europe and South America, generally have various energy sources available, resulting in greater LNG price sensitivity.²⁶

The LNG market has demonstrated two notable developments in recent years. First, as a result of the recent divergence of oil and natural gas prices, LNG prices (which are typically contractually linked to the price of oil) have become decoupled from the price of natural gas (as illustrated below). Second, in recent years, the duration of LNG contracts has shifted from longer term to shorter term. The traditional long-term (e.g., 20- to 30-year) contract model has two components: a sales contract and a transportation contract. The prices are indexed to an agreed measure (e.g., a hub), while volume is agreed upon on a take-or-pay basis—i.e., the seller agrees to a minimum delivery and the buyer pays a penalty in the event that it does not take the agreed-upon volume.²⁷ In recent years, a rise in LNG contracts with destination flexibility, a surge in regasification capacity, price differentials across regions and growth in the LNG shipping fleet have strengthened the short-term LNG market.²⁸ In 2013, the short-term market (i.e., contracts of 5 years or fewer) comprised 33% of global LNG trade,²⁹ up from 20% five years prior and 8% ten years prior.³⁰



²⁵ IGU World LNG Report.

²⁶ BCG Report.

²⁷ BCG Report.

²⁸ BCG Report.

²⁹ IGU World LNG Report.

³⁰ “Prospects for Development of an Asian LNG Trading Hub,” King & Spalding, February 2014.

³¹ Henry Hub is a natural gas distribution hub in Louisiana. Henry Hub’s prices are generally viewed as an indicator for the prices in the broader North American natural gas market.

³² West Texas Intermediate (“WTI”) is a grade of crude oil; its prices are used as a benchmark for oil prices.

³³ Japan LNG Import refers to the average price of LNG imports to Japan.

³⁴ U.K. Gas Import refers to the average price paid for natural gas imports to the U.K.

2. Overview of Global Market Participants

The global LNG market involves an ecosystem of participants whose constructive involvement is necessary to any export development project. The table below describes many of these participants.

GLOBAL LNG MARKET PARTICIPANTS

SOVEREIGN GOVERNMENTS	<ul style="list-style-type: none"> ■ Control exploration and production rights on their land; a principal player in the LNG value chain; their approval and support can be necessary in any development project ■ LNG export market is highly concentrated in a small number of nations: <ul style="list-style-type: none"> ■ Qatar (33%), Malaysia (10%) and Australia (9%)³⁵ ■ World's largest reserves of natural gas are found in: <ul style="list-style-type: none"> ■ Russia (1,688 Tcf) and Iran (1,187 Tcf)³⁶
PRODUCERS	<ul style="list-style-type: none"> ■ Obtain land rights from governments, and explore and extract energy assets ■ Natural gas producer market is relatively concentrated; large players can be broadly categorized into: <ul style="list-style-type: none"> ■ State-owned entities such as Gazprom (1,241 Tcf of gas reserves)³⁷ or Saudi Aramco (288 Tcf)³⁸ ■ Multinational entities such as Exxon (26 Tcf), BP (10 Tcf) and Conoco (10 Tcf)³⁹
ENGINEERING AND CONSTRUCTION COMPANIES	<ul style="list-style-type: none"> ■ Develop the infrastructure necessary for gas treatment (prior to pipeline transportation), LNG liquefaction and, at a later stage, regasification (i.e., transformation of LNG into gas) ■ LNG engineering and construction market is very concentrated, given that there are few companies with the expertise and scale necessary to develop these large-scale projects; major players include: <ul style="list-style-type: none"> ■ Bechtel (private; 2013 revenue of ~\$39 billion) ■ Fluor (~\$9 billion market capitalization) ■ Chicago Bridge & Iron (~\$5 billion market capitalization) ■ KBR (~\$2 billion market capitalization)
PIPELINE OPERATORS	<ul style="list-style-type: none"> ■ Transport gas through pipelines to LNG processing and export facilities ■ Natural gas pipeline industry is heavily concentrated; major North American players include: <ul style="list-style-type: none"> ■ Enbridge (~\$44 billion market capitalization) ■ TransCanada (~\$35 billion market capitalization) ■ Spectra (~\$25 billion market capitalization) ■ Kinder Morgan (~\$44 billion market capitalization) ■ Energy Transfer Partners (~\$23 billion market capitalization)
SHIPPING/ TRANSPORTATION	<ul style="list-style-type: none"> ■ Transport LNG over water to end markets ■ Players include both LNG producers and independent shipping companies;⁴⁰ top three companies (Nakilat, MISC and Bonny Gas) tied to specific projects (in Qatar, Malaysia and Nigeria, respectively) ■ There are currently 357 LNG vessels worldwide⁴¹ <ul style="list-style-type: none"> ■ In contrast to the concentrated export market, the three largest companies comprise only about 18% of the worldwide fleet, by number of vessels
UTILITIES (E.G., POWER PRODUCERS, GAS DISTRIBUTION COMPANIES)	<ul style="list-style-type: none"> ■ Power producers generate electricity using regasified LNG ■ Gas distribution companies deliver regasified LNG as natural gas to customers ■ Countries with the largest regasification capacity include: <ul style="list-style-type: none"> ■ Japan (184 MTPA), U.S. (132 MTPA), Korea (92 MTPA) and Spain (42 MTPA) ■ Utility industry is relatively fragmented globally, but concentrated on a local basis as incumbent players provide the bulk of services for a particular region <ul style="list-style-type: none"> ■ These companies include the state-owned utility Korea Gas Corporation ("KOGAS"), the largest single LNG importer in the world (41 MTPA);⁴² the Japanese utilities Tokyo Electric Power and Chubu Electric Power, which now purchase LNG together and are one of the largest importing entities in the world (40+ MTPA);⁴³ and the state-owned Taiwanese utility CPC Corporation (13 MTPA)⁴⁴

Source: FactSet.

Note: Pricing data as of January 2, 2015.

³⁵ IGU World LNG Report.

³⁶ IGU World LNG Report.

³⁷ "Gas and oil reserves," Gazprom.

³⁸ "Facts & Figures 2013," Saudi Aramco.

³⁹ EY Oil and Gas Study.

⁴⁰ "Liquefied Natural Gas: Understanding the Basic Facts," DOE, 2005.

⁴¹ IGU World LNG Report.

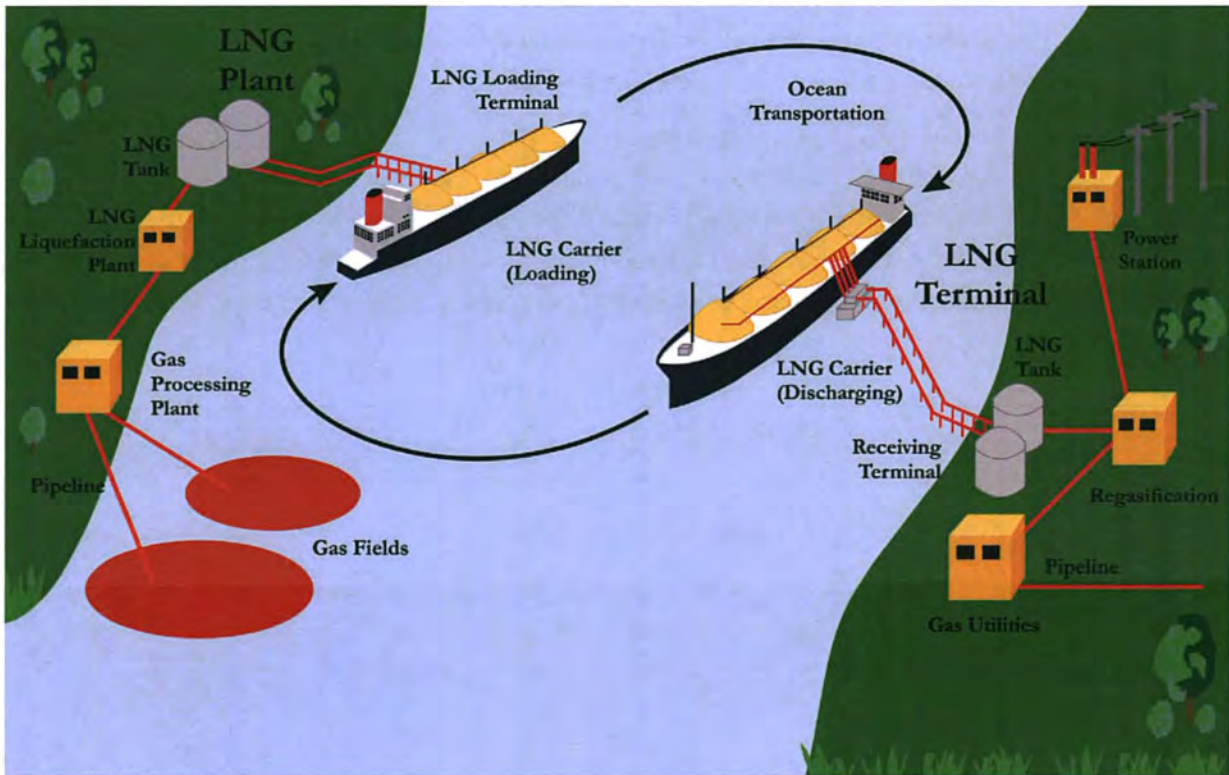
⁴² "South Korean KOGAS Looks to O10-17 LNG Cargoes in Oct-Nov: Sources," Platts, August 28, 2014.

⁴³ "Tepco, Chubu Electric Form World's Largest LNG Buyer," Wall Street Journal, October 7, 2014.

⁴⁴ "Taiwan Keen to Import US LNG from Shale Gas-fed Projects: Report," Platts, June 6, 2013.

The illustration below demonstrates the relationships among many of these players in the global LNG value chain.

GLOBAL LNG VALUE CHAIN

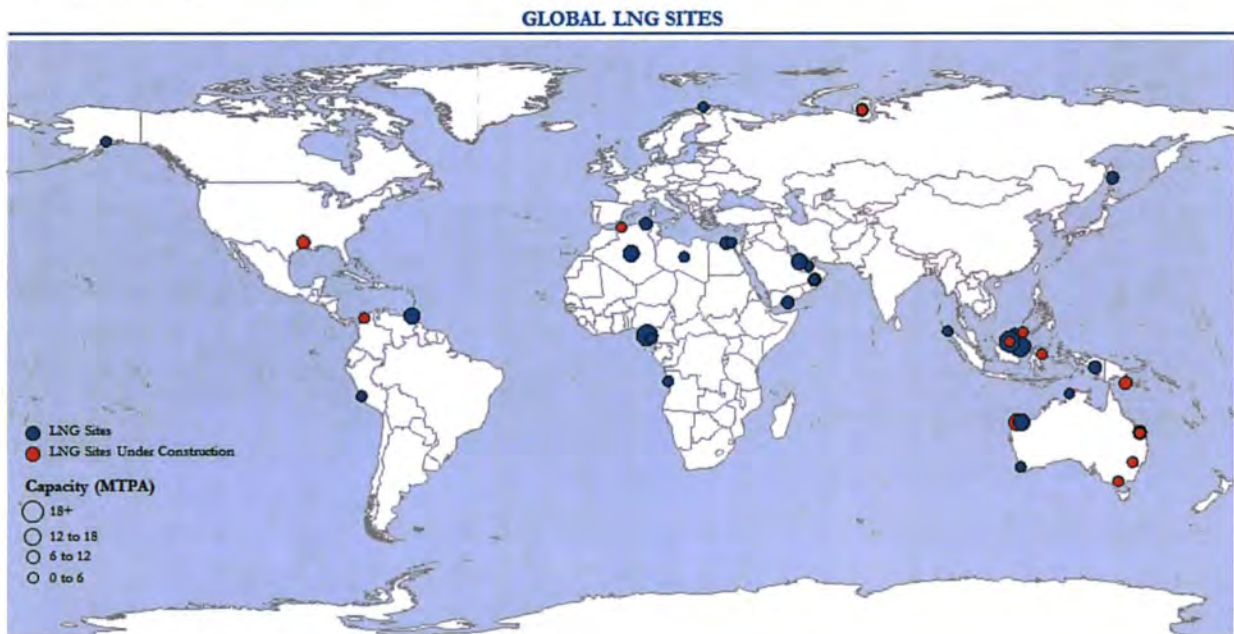


Source: PTTLNG, modified.

3. Overview of Global LNG Projects

The maps below show LNG projects worldwide that are either complete or under construction. As of 2014, there are 31 existing LNG sites, with an additional 22 sites under construction. The existing sites have a capacity of 294 MTPA, for an average of 9.5 MTPA per site. The vast majority of facilities that are under construction will likely come online in the next three years, with 73% of new liquefaction capacity expected to be completed by 2017 and 90% by 2018.⁴⁵

Existing global LNG sites are generally dispersed geographically. However, new supply, evidenced by sites under construction, is centered in Australia and Indonesia and, to a lesser extent, the Americas. This demonstrates Europe's perceived decreasing share of future demand and the increasing demand of northern Pacific Rim countries, such as Japan. Despite the concentration of new LNG site construction, the number of countries exporting LNG is still expected to grow only slightly, as new projects come online in Colombia and Russia.⁴⁶



Source: IGU World LNG Report.

Note: Single dots may represent multiple LNG plants at a single site.

GLOBAL LNG SITES		
	Number	Capacity (MTPA)
Existing	31	294
Under Construction	22	117
Total	53	411

Source: IGU World LNG Report.

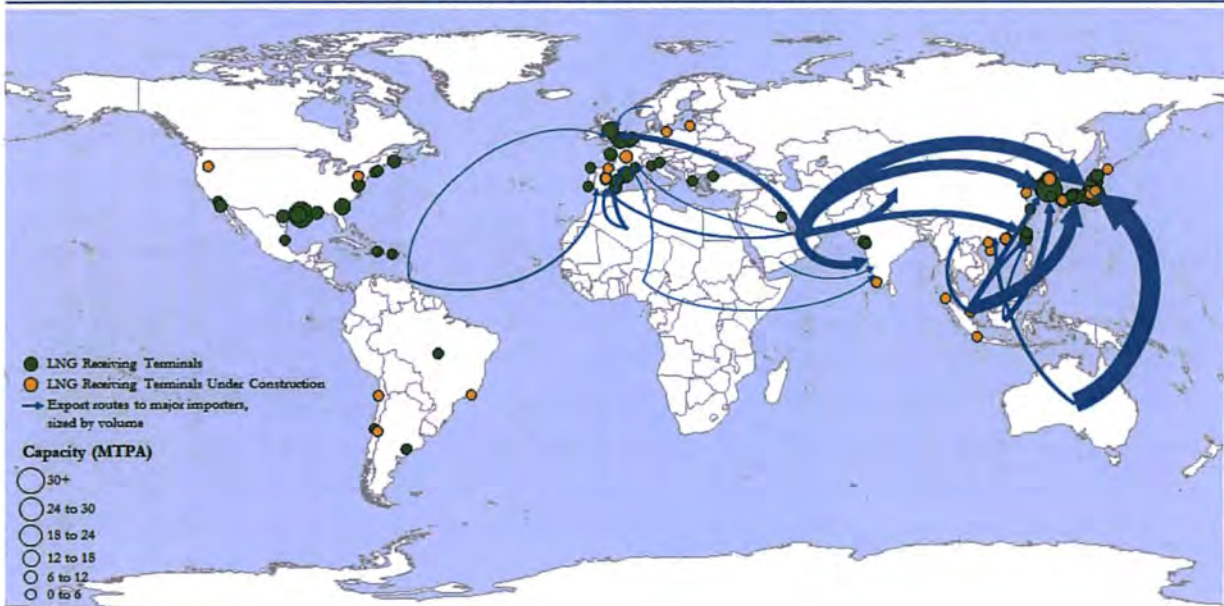
⁴⁵ IGU World LNG Report.

⁴⁶ IGU World LNG Report.

Worldwide, there are 74 existing LNG receiving terminals, with an additional 26 under construction. The receiving terminals have an average capacity of 8.5 MTPA. The prevalence of existing receiving terminals in Western European countries reflects these countries' historical position as major importers of LNG. The numerous existing receiving terminals in the U.S. reflect the country's push for fuel alternatives prior to the discovery of substantial amounts of domestic shale gas and cost-effective extraction technologies that have led to vast amounts of domestic gas in the Lower 48.⁴⁷

The number of countries importing LNG, which has exceeded the number of exporting countries since 2002, is expected to continue to grow. In the coming years, Asian nations, in particular China, Japan and Indonesia, will likely be constructing major LNG receiving terminals. The relatively smaller capacity of LNG terminals in South American nations reflects the use of LNG as a cost-effective near-term energy solution.⁴⁸

GLOBAL LNG RECEIVING TERMINALS



Source: IGU World LNG Report.

Note: Single dots may represent multiple LNG receiving terminals at a single site.

GLOBAL LNG RECEIVING TERMINALS

	Number	Capacity (MTPA)
Existing	74	628
Under Construction	26	74
Total	100	701

Source: IGU World LNG Report.

⁴⁷ IGU World LNG Report.

⁴⁸ IGU World LNG Report.

B. Overview of Natural Resources in Alaska

The Alaska State Constitution provides that “it is the policy of the State to encourage the settlement of its land and the development of its resources by making them available for maximum use consistent with the public interest.”⁴⁹ Largely driven by this policy, oil extraction has been an integrated component of Alaska’s economy over the past 50 years, and revenues from oil production have constituted the vast majority of the State’s revenue. During this same period, the production of natural gas has been limited. Current forecasts of oil production, however, suggest that State revenues from this activity are likely to decrease significantly in the coming years. This trend (together with many other factors including increased global demand for LNG) has galvanized support for a large-scale natural gas project in Alaska.

1. Overview of Oil in Alaska

a. Resource Description

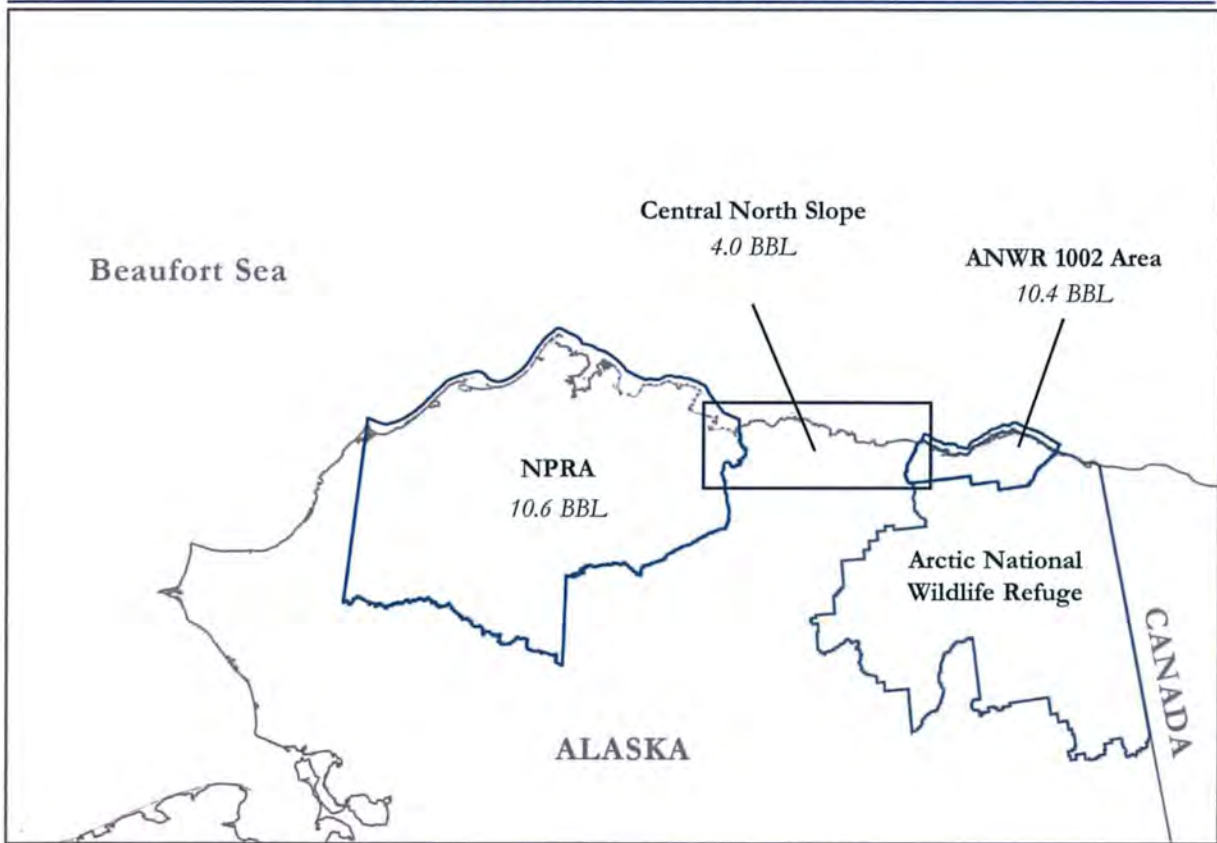
Oil production is critical to Alaska’s fiscal position and financial stability. According to the Fall 2014 Revenue Sources Book,⁵⁰ proceeds from oil contributed 88% of total deposits to Alaska’s General Fund for fiscal year (“FY”) 2014 (this includes production taxes, royalties, property taxes and corporate income taxes associated with oil production). Consequently, variations in the price or the production volume of oil can have a material effect on Alaska’s annual budget.

According to the U.S. Geological Survey (“USGS”), there are an estimated 24.9 billion barrels (“BBL”) of undiscovered, technically recoverable petroleum in the Arctic Alaska Petroleum Province (“AAPP”), which encompasses all land north of the Brooks Range and Herald Thrusts and, to date, accounts for the vast majority of oil reserves in Alaska. These oil reserves are spread across the North Slope of Alaska in three designated areas: the National Petroleum Reserve-Alaska (“NPRA”), Central North Slope and the Arctic National Wildlife Refuge (“ANWR 1002 Area”). NPRA has ~10.6 BBL of undiscovered oil, Central North Slope has ~4.0 BBL of undiscovered oil and ANWR 1002 Area has ~10.4 BBL of undiscovered oil. These reserves and their locations are illustrated on the following map.

⁴⁹ Alaska Constitution Article VIII, Section 1.

⁵⁰ “Fall 2014 Revenue Sources Book,” The State of Alaska, 2014 (“Fall 2014 Revenue Sources Book”).

AAPP REGIONS AND UNDISCOVERED OIL



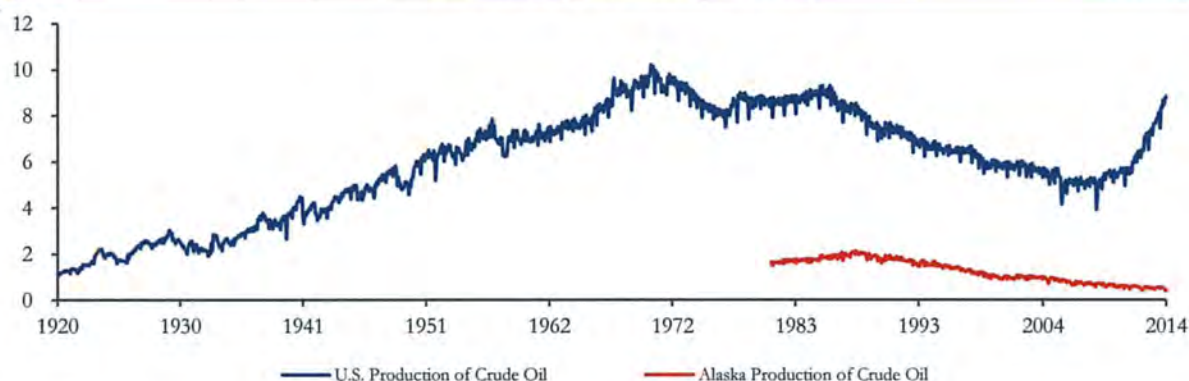
Source: U.S. Geological Survey Paper 1732-A.

b. Summary of Historical and Forecasted Oil Production and Operations

Alaska oil constitutes a significant, but decreasing, proportion of total U.S. production. U.S. and Alaska oil production peaked in 1970 and 1988, respectively. Since 1988, U.S. oil production has decreased consistently, and fell to 5.0 million barrels per day (“MMBD”) by 2008. However, since 2008, higher oil prices and new drilling technologies have stimulated industry activity in North Dakota, Texas and the Gulf of Mexico. Concurrently, Alaska production has continued to decrease, as illustrated in the following chart.

III. LNG BACKGROUND AND OVERVIEW

CRUDE OIL PRODUCTION (MMBD)



Source: EIA.

Following slight forecasted increases in production in 2015 and 2016, production from Alaska's currently-producing oil reserves is expected to decline each year over 2017 – 2024, yielding annual production from existing wells by 2024 that is approximately 44% of expected output in 2015. Even after taking into account forecasted new oil production, Alaska's overall production is expected to decrease to approximately 62% of expected 2015 output by 2024. These forecasts are summarized in the table and chart below.

ALASKA NORTH SLOPE OIL PRODUCTION FORECAST (MMBD)

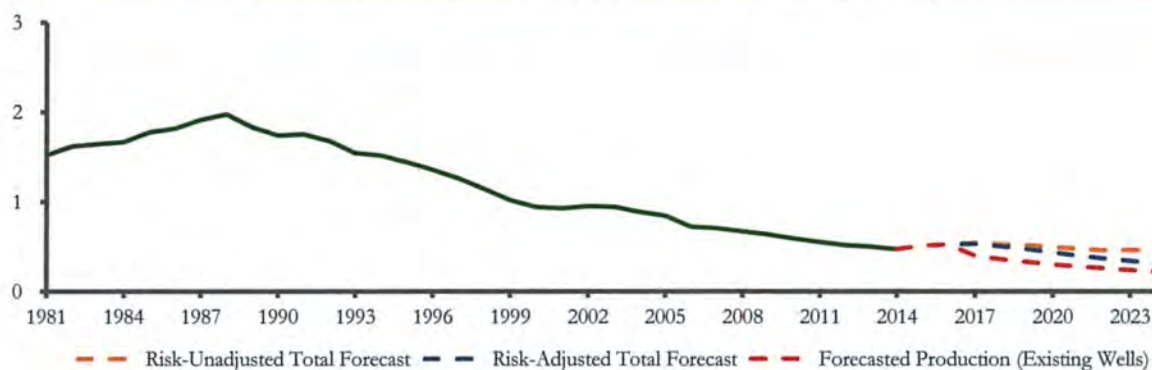
	2015 E	2016 E	2017 E	2018 E	2019 E	2020 E	2021 E	2022 E	2023 E	2024 E
Forecasted Production (Existing Wells)	0.510	0.524	0.397	0.359	0.329	0.302	0.278	0.258	0.239	0.222
Growth/ (Decline) Rate	4%	3%	(24%)	(9%)	(8%)	(8%)	(8%)	(7%)	(7%)	(7%)
Risk-Adjusted New Oil	0.000	0.000	0.137	0.144	0.145	0.134	0.122	0.111	0.104	0.092
Mem: New Oil Share of Risk-Adjusted Total Forecast	0%	0%	26%	29%	31%	31%	30%	30%	30%	29%
Risk-Adjusted Total Forecast	0.510	0.524	0.534	0.503	0.473	0.436	0.400	0.369	0.343	0.315
Year-Over-Year Forecasted Growth/ (Decline) Rate	0%	3%	2%	(6%)	(6%)	(8%)	(8%)	(8%)	(7%)	(8%)
Mem: Risk-Unadjusted Total Forecast ^(a)	0.510	0.524	0.539	0.523	0.514	0.494	0.474	0.459	0.462	0.455

Source: Fall 2014 Revenue Sources Book.

Note: Risk-adjusted amounts calculated by the State. Amounts represent the expected value of future production based on the size of the project and its likelihood of success.

(a) Reflects "high" case.

ALASKA NORTH SLOPE CRUDE OIL PRODUCTION (MMBD)



Sources: EIA and Fall 2014 Revenue Sources Book.

2. Overview of Natural Gas in Alaska

a. Resource Description

According to a report prepared by DeGolyer and MacNaughton⁵¹ (referenced in the Project’s U.S. Department of Energy (“DOE”) export application), there is an estimated supply of approximately 63.5 Tcf of natural gas in Alaska. This supply is spread between the North Slope, Cook Inlet and offshore Continental Shelf (in depths of less than 200 meters); a summary of the resource is presented below.

OVERVIEW OF ALASKA NATURAL GAS RESOURCE

ALASKA REGION AND ASSESSMENT SEGMENT	RESERVES (Tcf)	RESOURCES MOST LIKELY		TOTAL RESERVES + RESOURCES (Tcf)
		PROBABLE (Tcf)	POSSIBLE (Tcf)	
Alaska Onshore				
North Slope	0	30.2	15.0	45.2
Cook Inlet	1.1	0.7	1.4	3.2
Alaska Offshore (0 – 200 Meters)				
Beaufort Shelf	0	2.0	12.0	14.0
Cook Inlet Basin	0	0.4	0.7	1.1
Grand Total – Expected Supply Scenario	1.1	33.3	29.1	63.5

Source: DeGolyer and MacNaughton Report.

b. Existing Alaska Natural Gas Operations

Alaska’s natural gas production comes primarily from two regions: the Cook Inlet and the North Slope. Although natural gas production in the State is several orders of magnitude smaller than that of oil, natural gas has nonetheless played a significant role in Alaska’s economy, both as a primary fuel source for generating electricity and heating Alaska’s cities, and as an export product in its LNG form.

i. Prudhoe Bay

The Prudhoe Bay oil discovery in 1968 in the North Slope of Alaska that led to the construction of the Trans-Alaska Pipeline System (“TAPS”) also included natural gas estimated at the time to be 26 Tcf (and since revised upward as outlined above). Since 1968, various plans have proposed to move North Slope gas to market. To date, Alaska does not export North Slope gas, although the gas is used for electricity generation in the North Slope and for enhancing oil recovery in Prudhoe Bay

⁵¹ “Report on a Study of Alaska Gas Reserves and Resources for Certain Gas Supply Scenarios as of December 31, 2012,” DeGolyer and MacNaughton, Prepared for Locke Lord LLP, April 2014 (“DeGolyer and MacNaughton Report”).

by reducing oil surface tension and aiding mobility. The remaining extracted gas is re-injected into the Prudhoe Bay reservoir to maintain pressure and help increase oil production.⁵²

ii. Cook Inlet

For over half a century, Cook Inlet natural gas exports have served as an engine for Alaska economic growth. In 1959, the year that Alaska became a state, Cook Inlet became the site of the State's first major commercial gas discovery. Since then, Cook Inlet has produced more than 7.8 Tcf of gas for in-State use and export.⁵³

Tidewater natural gas from Cook Inlet is used predominantly as a fuel for heating Alaska's largest city, Anchorage, and the "railbelt" area connected to the electrical grid. Additionally, approximately one-third of the natural gas produced at Cook Inlet had historically been cooled into LNG and exported to Japan. The LNG plant at Cook Inlet, located on the Kenai Peninsula in Nikiski, Alaska, operated between 1969 and 2011. This plant, the world's second-ever intercontinental LNG project, both monetized natural gas resources in Alaska and spurred the initial destination infrastructure that has allowed Japan to become the world's leading LNG importer.⁵⁴

In the early 2000s, local demand for natural gas began to expand in Alaska. In 2011, the EIA estimated that Alaska consumers used 85 billion cubic feet ("Bcf") of natural gas, which accounted for 63% of power generation in the State and 53% of heating fuel. Over the same time period, gas production in Cook Inlet declined, primarily because additional reserves were not developed. As a result of these changing dynamics, the LNG plant at Cook Inlet ceased operations in 2011.⁵⁵

However, by Fall 2013, new drilling had produced a surplus of gas supply and the State requested that Conoco renew its DOE export permit to provide Cook Inlet producers with access to LNG end markets. In May 2014, the Cook Inlet LNG plant resumed shipments with a renewed permit. The approved permit allowed for the export of LNG to non-free trade countries, most notably Japan.⁵⁶

⁵² Fall 2013 Revenue Sources Book.

⁵³ Fall 2013 Revenue Sources Book.

⁵⁴ Fall 2013 Revenue Sources Book.

⁵⁵ Fall 2013 Revenue Sources Book.

⁵⁶ "ConocoPhillips to reopen LNG plant, resume exports," Alaska Journal of Commerce, April 17, 2014.

C. Overview of Alaska Natural Gas Legislation

Since 1968, various plans have proposed to move North Slope natural gas from Prudhoe Bay to markets, including to the Pacific Rim and the Lower 48. Although no North Slope gas has been exported to date, both Federal and State efforts have brought projects to near realization. These efforts are highlighted in the timeline below.

TIMELINE OF ALASKA NATURAL GAS LEGISLATION

DATE	EVENT DESCRIPTION
1976	■ The U.S. Congress passes the Alaska Natural Gas Transportation Act (“ANGTA”), which provides for the expedited development of a pipeline to deliver natural gas from Alaska to the Lower 48
1977	■ The U.S. and Canadian governments approve the construction of the Alaska Highway Project, a pipeline along a route that follows the Alaska Highway through Canada to reach the Lower 48
1977	■ Federal Power Commission, now the Federal Energy Regulation Commission (“FERC”), recommends an overland pipeline route through Canada to move Alaska gas to the Lower 48
1978	■ Congress passes the Natural Gas Policy Act and the Powerplant and Industrial Fuel Use Act (“Fuel Use Act”) in response to natural gas shortages that had been due to federally regulated price controls. The Fuel Use Act restricted construction of new power plants and boilers using natural gas and oil as primary fuels, encouraging instead the use of coal, nuclear energy and alternative fuels
1980s	■ U.S. Maritime Administration conducts study indicating that U.S. LNG sales to Pacific Rim nations had greater economic potential than those to West Coast U.S. markets, but market prices for LNG failed to support the commencement of such a project
1987	■ Congress lifts previous Fuel Use Act restrictions on new-build natural gas and oil power plants
1998	■ Alaska Legislature passes Alaska Stranded Gas Development Act (“Stranded Gas Act”), which allows the State to negotiate special fiscal, tax and royalty terms, and regulatory terms with North Slope oil producers for “stranded gas,” which is defined as gas that “is not being marketed due to prevailing costs or price conditions as determined by an economic analysis by the Department of Revenue Commissioner for a particular project”
2001	■ National Energy Plan includes a recommendation to expedite construction of an Alaska natural gas pipeline to serve the Lower 48. Alaska natural gas interagency task force formed; includes the State Department, Department of Interior, Department of Transportation, DOE and FERC
2002	■ Alaska voters approve a ballot measure that creates the Alaska Natural Gas Development Authority (“ANGDA”), vested with the authority to act as a shipper and obtain financing for a project
2003	■ Alaska Legislature reauthorizes Stranded Gas Act
2004	■ Congress passes the Alaska Natural Gas Pipeline Act, which establishes a federal project coordinator, provides for loan guarantees, and offers tax and regulatory incentives for a pipeline project
2007	■ Alaska Legislature passes the Alaska Gasline Inducement Act (“AGIA”), which provides for 50% reimbursement for developers’ expenses up to \$500 million, in exchange for agreeing to terms, including following the State’s timeline
2010	■ Alaska Legislature creates the AGDC as a subsidiary of the Alaska Housing Finance Corporation; tasks the AGDC with advancing the Alaska Stand Alone Pipeline (“ASAP”)
2013	■ Alaska Legislature makes AGDC an independent corporation, folds together and consolidates operations with ANGDA
2014	■ SB 138 signed into law, facilitating Alaska participation in the Project

Sources: *Fall 2013 Revenue Sources Book* and *“Searching for a Market: The 40-year Effort to Develop an Alaska Natural Gas Project,” Office of the Federal Coordinator, July 2014 (“Office of the Federal Coordinator—‘Searching for a Market’”).*

D. Overview of Previous and Current Alaska Natural Gas Projects

Efforts to monetize the large natural gas reserves in Prudhoe Bay began in the mid-1970s, shortly before the completion date of TAPS. Since then, every Alaska Governor has tried to spur construction of a natural gas pipeline. Those efforts have thus far been unsuccessful; however, in recent years, the importance of the construction of such a pipeline has increased as North Slope oil production has declined and the economics of LNG exports have become more attractive.⁵⁷

In 1976, Congress passed ANGTA to expedite the development of a pipeline to deliver North Slope natural gas to the Lower 48. The following year, the U.S. and Canadian governments approved the construction and ownership of a pipeline along a route that followed the Alaska Highway through Canada to reach customers in the Lower 48 (the “Alaskan Northwest Project”). However, deregulation of the U.S. domestic natural gas industry, through legislation such as the 1978 Natural Gas Policy Act and Fuel Use Act, led to an increase in the supply of natural gas and a price reduction for the destination markets of the Alaskan Northwest Project. As a result, the pipeline project never materialized.⁵⁸

Throughout this period, various other projects competed with the Alaskan Northwest Project for regulatory approval. The El Paso LNG project contemplated transporting North Slope natural gas to California by first tracing the route of TAPS from Prudhoe Bay to Valdez, and then linking up with LNG export facilities that would ship to California. There was also a proposal for an “over-the-top” offshore route, dubbed Arctic Gas, which would have crossed over the Arctic Ocean to Canada and ultimately connected with U.S. East Coast markets.⁵⁹ These projects were rejected under the same federal certification process that approved the Alaska Northwest Project. Interest in a gas pipeline did not pick up significantly again until the late 1990s when rising prices and demand in the Lower 48 galvanized both policymakers and the energy industry.⁶⁰

The resurgence of U.S. demand for natural gas circa 2000 prompted reconsideration of constructing a natural gas pipeline. Policymakers in the Alaska Legislature as well as in Congress passed preliminary legislation for natural gas pipeline projects connecting Alaska with the Lower 48. These laws led to negotiations between the State administration and the producers that culminated in a contract in 2006 that was rejected by the Alaska State Legislature.⁶¹

In 2007, the Alaska State Legislature passed the AGIA, which provided for 50% reimbursement for a developer’s expenses (up to \$500 million) in exchange for agreeing to terms, including following the State’s timeline.⁶² TransCanada, a Canadian pipeline company, was awarded the license, and Exxon later agreed to work with them on the project. In 2008, BP and Conoco launched a competing joint venture, Denali, which contemplated a pipeline that crossed Alaska, the Yukon and

⁵⁷ Fall 2013 Revenue Sources Book.

⁵⁸ Fall 2013 Revenue Sources Book.

⁵⁹ Office of the Federal Coordinator—“Searching for a Market”.

⁶⁰ Fall 2013 Revenue Sources Book.

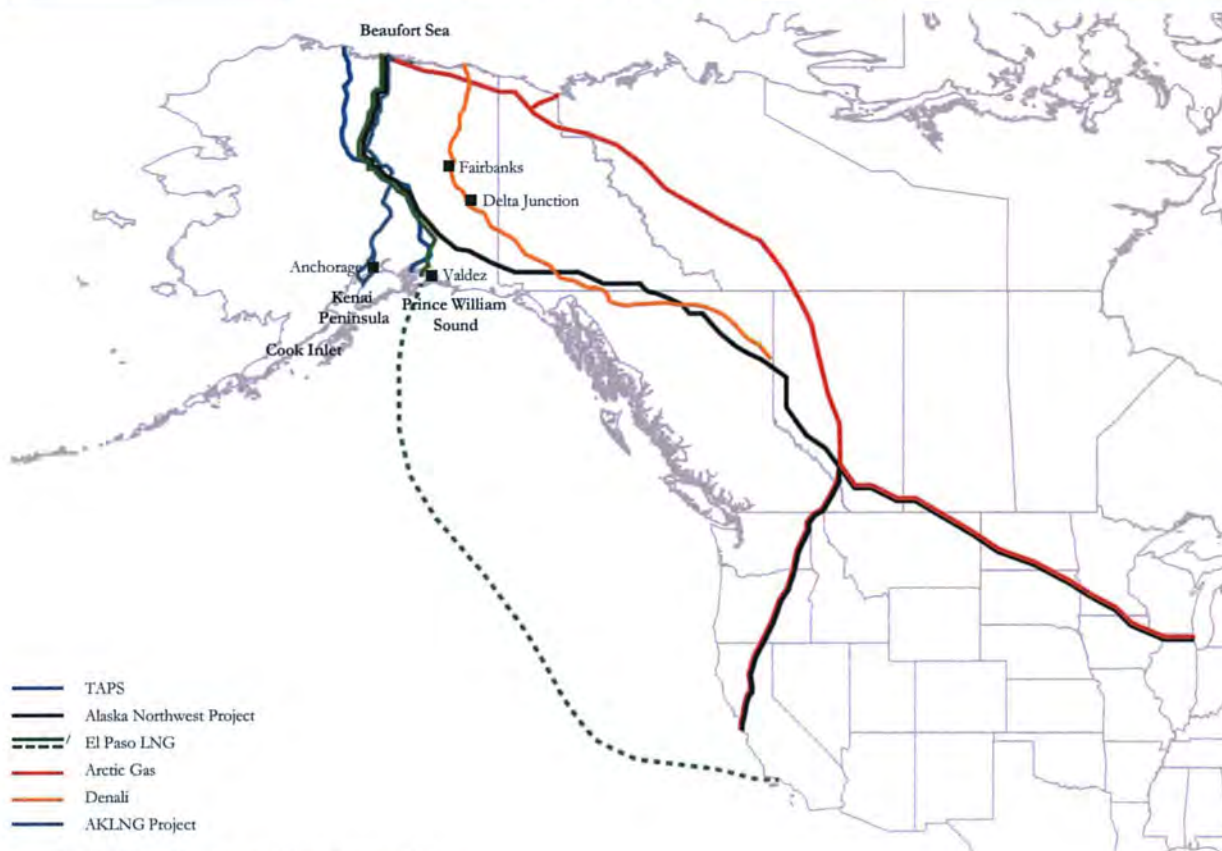
⁶¹ Fall 2013 Revenue Sources Book.

⁶² Office of the Federal Coordinator—“Searching for a Market.”

British Columbia to Alberta. These projects were ultimately abandoned after changed dynamics in the U.S. natural gas market made exports to the Lower 48 economically infeasible.⁶³

In 2012, the chief executives of Exxon, Conoco and BP wrote to Alaska’s Governor stating that they, together with TransCanada,⁶⁴ had begun studying a pipeline to a Southcentral Alaska LNG facility that would export gas to Asian markets, rather than the Lower 48—these efforts initiated the currently proposed AKLNG Project. The Project is estimated to have a total cost of \$45 – \$65 billion (in 2012 dollars), and would include a gas treatment plant, a 42-inch diameter pipeline and an LNG export facility in Nikiski on the Kenai Peninsula.⁶⁵

PREVIOUS AND CURRENT ALASKA NATURAL GAS PROJECTS



Sources: Fall 2013 Revenue Sources Book and Office of the Federal Coordinator.

⁶³ Fall 2013 Revenue Sources Book.

⁶⁴ In October 2011, Alaska’s Governor had requested that these parties work together to evaluate the economic feasibility of a project to address in-State gas needs and serve LNG export markets abroad.

⁶⁵ Fall 2013 Revenue Sources Book.

E. Investment Thesis

The supply of natural gas in Alaska (and particularly in the North Slope) represents a valuable investment opportunity for the State and its residents. Given current downward trends in Alaska oil production and associated State revenue, in-State natural gas production could support Alaska’s State budget well into the future. Political figures within the State have recognized the opportunity for natural gas production to stabilize Alaska’s budget and, consequently, support for the Project has been growing. Other stakeholders, including North Slope producers and pipeline operators, see the potential development of Alaska’s gas as a compelling investment decision. Most importantly, Alaska citizens stand to benefit from the development of the Project in many ways, including in-State job opportunities, lower-priced natural gas and Project revenues that flow to the State.

Alaska’s supply of natural gas is abundant by many measures. For example, the export of 20 MTPA (i.e., the level proposed in the Project’s DOE export license application) would rank Alaska as the fourth-highest exporter of LNG in the world, following Qatar (81 MTPA), Malaysia (25 MTPA) and Australia (23 MTPA).⁶⁶ Below is a table that demonstrates how an illustrative 20 MTPA export from Alaska would compare with exports from the top 10 LNG exporting countries over the past several years.

COMPARISON OF ALASKA’S POTENTIAL EXPORTS WITH THAT OF OTHER EXPORTERS (MTPA)

2009		2010		2011		2012		2013		2014E	
Qatar	38.2	Qatar	58.7	Qatar	58.7	Qatar	79.5	Qatar	77.2	Qatar	79.8
Malaysia	22.8	Indonesia	23.9	Malaysia	23.2	Malaysia	23.4	Malaysia	24.7	Malaysia	24.8
Alaska	20.0	Malaysia	23.2	Indonesia	23.9	Australia	21.2	Australia	22.2	Australia	23.7
Indonesia	19.4	Alaska	20.0	Alaska	20.0	Nigeria	20.6	Alaska	20.0	Alaska	20.0
Australia	18.7	Australia	19.5	Australia	19.5	Alaska	20.0	Indonesia	17.0	Nigeria	19.3
Trinidad	15.9	Nigeria	18.4	Nigeria	18.4	Indonesia	19.1	Nigeria	16.9	Indonesia	18.4
Algeria	15.9	Trinidad	15.4	Trinidad	15.4	Trinidad	14.7	Trinidad	14.6	Trinidad	14.7
Nigeria	12.1	Algeria	14.4	Algeria	14.4	Algeria	11.1	Algeria	10.9	Algeria	12.6
Egypt	10.0	Russia	10.5	Russia	10.5	Russia	11.0	Russia	10.8	Russia	10.3
Oman	8.4	Oman	8.9	Oman	8.1	Oman	8.3	Oman	8.6	Oman	8.4
Brunei	6.8	Egypt	7.3	Brunei	6.9	Brunei	6.9	Yemen	7.2	Brunei	7.2

Source: IGU World LNG Report.

The AKLNG Project holds a number of advantages over existing export operations in the rest of the world. These advantages include higher efficiency liquefaction and gas treatment, due to cold temperatures in Alaska. According to the Office of the Federal Coordinator, Alaska’s efficiency

⁶⁶ Based on 2013A export volumes.

advantage over the Middle East could range from 12% – 14% due to average temperatures that are 44°F cooler (Alaska’s 36°F average vs. the Middle East’s 80°F). Since a key part of the liquefaction process involves cooling the gas to -259°F, colder temperatures yield more energy-efficient, less expensive gas treatment and liquefaction processes, which in turn lower the cost of producing each unit of LNG. Furthermore, the higher efficiency processes require less powerful equipment, lowering upfront capital costs.⁶⁷

Another advantage is that Alaska natural gas has a higher heat content than that of competitors, making it more valuable in Asian end markets. This feature renders North Slope gas “market-ready” for Japan, South Korea and Taiwan in a way that, for example, Lower 48 natural gas is not. Alaska “wet” gas typically has a heat content of ~1.1 million British thermal units (“MMBtu”) per thousand cubic feet (“Mcf”) whereas “dry” U.S. pipeline gas typically has a heat content of ~1.02 MMBtu/Mcf. Although Asian end markets can convert drier gas into wet gas—and, at scale, can do so economically—the conversion process involves infrastructure and resources which render the drier gas costlier.⁶⁸

Geographically, Alaska is well positioned to access high-demand markets in the Pacific Rim. Nikiski is roughly 3,800 miles from the major Japanese port of Yokohama and several nearby LNG terminals. By contrast, the proposed Kitimat project in British Columbia is almost 4,500 miles from Yokohama, and Russia’s Yamal project in the Arctic is 7,800 miles away (the route is also ice-blocked much of the year). Additionally, direct access to Pacific countries proves a significant advantage over, for example, Gulf projects that face chokepoints (e.g., Panama Canal) and therefore higher shipping costs in reaching Asian markets.⁶⁹

The Project provides other significant advantages such as low resource risk, given the large proven resources in Prudhoe Bay. Additionally, use of the existing infrastructure in Prudhoe Bay as well as the TAPS route makes the AKLNG Project more economically feasible relative to competing opportunities and lessens the environmental impact of the Project’s development. Furthermore, the State is a highly stable governmental entity as compared to countries that are the site of large-scale development projects (e.g., Nigeria, Russia, etc.). Lastly, gas extraction will likely improve production efficiency in adjacent oil fields by using Point Thomson gas to maintain pressure in Prudhoe Bay oil fields.

⁶⁷ “Alaska’s Frigid Climate Could Give State an Edge in LNG,” Office of the Federal Coordinator, June 2014. The cold climate, however, is not altogether beneficial. These advantages are to some extent offset by the higher costs of development and maintenance in colder environments. For example, the remote Arctic location of Prudhoe Bay and Point Thomson creates logistical issues during the development stage. Massive gas treatment plant modules may be delivered only in the summer months due to Arctic ice blocking routes in the winter.

⁶⁸ “Alaska LNG Could Have Right Heat Content for Asia Buyers,” Office of the Federal Coordinator, August 2013.

⁶⁹ “Early Planning, Design, Engineering Are Key to LNG Project Success,” Office of the Federal Coordinator, February 2014.

IV AKLNG Project Overview

IV. AKLNG Project Overview

Currently in its Pre-FEED phase, the AKLNG Project involves a diverse set of stakeholders, including citizens of Alaska, communities and municipalities, State and Federal government agencies, large multinational companies, and many other individuals and entities. The Project will require a substantial investment in infrastructure, including the construction of gas treatment and storage facilities, an 800-mile pipeline and marine facilities for the trans-Pacific shipment of LNG. As currently contemplated, the Project will involve approximately 2 – 4 years of additional planning followed by an estimated 5 – 6 years of construction. When completed circa 2024, the AKLNG Project is expected to be the largest LNG project in the U.S. and is expected to deliver LNG to various markets in Asia.

A. History

The AKLNG Project started to take form in October 2011, when Alaska’s Governor requested that Exxon, BP, Conoco and TransCanada work together to evaluate the economic feasibility of a project to address in-State gas needs and serve LNG export markets abroad. By 2012, these parties had begun to coordinate their efforts and contribute resources to explore the opportunity. The parties then negotiated a Heads of Agreement with the AGDC and the State of Alaska, and ultimately executed this agreement in January 2014. The Heads of Agreement establishes non-binding guiding principles and partner roles for the Project as well as important commercial and operating arrangements among each of the key Project parties. The State’s decision to partner with these parties allows for, among other things, cost and risk sharing, alignment of interests among key Project stakeholders and State participation in key aspects of the Project decision-making process.⁷⁰ Following the execution of the Heads of Agreement, the Project entered the pre-FEED phase in mid-2014.

B. Description, Overview of Facilities and Map

As currently contemplated, the Project primarily consists of the following three components: the GTP, the Pipeline and the LNG Plant. Natural gas produced at the Prudhoe Bay and Point Thomson fields in the North Slope will be transported via regional gathering pipes⁷¹ to the GTP, where it will be treated to a level of quality (e.g., free of impurities, byproducts, water, etc.) sufficient to be transported through the Pipeline. The GTP is expected to be located adjacent to the existing Prudhoe Bay fields. The Pipeline will follow an 800-mile route from the GTP in Prudhoe Bay through Livengood in central Alaska and south to Cook Inlet. Multiple offtake points are planned along the route of the Pipeline to facilitate in-State gas distribution. After reaching Cook Inlet, the

⁷⁰ “Heads of Agreement By and Among The Administration of the State of Alaska, AGDC, TransCanada Alaska Development Inc., ExxonMobil Alaska Production Inc., ConocoPhillips Alaska Inc. and BP Exploration (Alaska) Inc. for the Alaska LNG Project,” January 2014 (“Heads of Agreement”).

⁷¹ The gathering pipelines connecting the Prudhoe Bay/Point Thomson facilities with the GTP are also considered to be part of the Project.

gas will be processed at the LNG Plant, where it will be liquefied, stored at local storage facilities and shipped from a marine export terminal.

ALASKA LNG PROJECT MAP



Source: "Project Overview with AGDC," Alaska LNG Project Presentation, May 7, 2014 ("Project Overview with AGDC").

C. Key Stakeholders

The AKLNG Project involves a large number of stakeholders with various levels of participation, including the following parties:

	DESCRIPTION ⁷²
PROJECT SPONSORS	STATE OF ALASKA <ul style="list-style-type: none"> Pursuant to SB 138, intends to become a part-owner of the AKLNG Project, with a currently contemplated economic interest of 25%
	EXXON <ul style="list-style-type: none"> Multinational oil and gas company involved in upstream (exploration and production) and downstream (refining and distribution) energy markets, as well as chemicals manufacturing and the marketing of Exxon's various products Market capitalization of ~\$395 billion (largest publicly-traded oil and gas company in the world) Among the producers involved in the development of North Slope natural gas (36% ownership of Prudhoe Bay,⁷³ 62% ownership of Point Thomson⁷⁴)
	BP <ul style="list-style-type: none"> Multinational oil and gas company involved in upstream and downstream energy markets, as well as chemicals manufacturing and the marketing of BP's various products Market capitalization of ~\$115 billion Among the producers involved in the development of North Slope natural gas (26% ownership of Prudhoe Bay,⁷³ 32% ownership of Point Thomson⁷⁴)
	CONOCO <ul style="list-style-type: none"> Multinational oil and gas company involved exclusively in upstream energy markets Market capitalization of ~\$85 billion Among the producers involved in the development of North Slope natural gas (36% ownership of Prudhoe Bay,⁷³ 5% ownership of Point Thomson⁷⁴)
	TRANSCANADA <ul style="list-style-type: none"> North American energy company involved in the development and ownership of oil and gas pipelines, power generation and gas storage facilities Market capitalization of ~\$40 billion Potential partner of the State for the GTP and Pipeline
	AGDC <ul style="list-style-type: none"> An independent, public corporation of the State established to develop, finance and operate pipelines and other energy systems within the State, including the Project's LNG Plant
ALASKA ENTITIES	LEGISLATURE <ul style="list-style-type: none"> Passed SB 138 in April 2014 Must approve contracts between the State and other parties with a Project interest before these contracts are to become effective <ul style="list-style-type: none"> Contracts include the Heads of Agreement, as well as the Memorandum of Understanding ("MOU") and Firm Transportation Services Agreement ("FTSA") between the State and TransCanada
	MUNICIPALITIES/ COMMUNITIES⁷⁵ <ul style="list-style-type: none"> Stand to benefit directly and indirectly from the development of the Project; SB 138 requires: <ul style="list-style-type: none"> Advisory planning group to advise on municipal involvement in the Project Department of Revenue to develop a plan and suggest legislation for municipalities, regional corporations and residents of the State to acquire ownership interests in the Project The establishment of the Alaska Affordable Energy Fund to develop infrastructure to deliver energy to areas of the State that are not expected to have access to the Pipeline⁷⁶
	NATIVE CORPORATIONS <ul style="list-style-type: none"> Stand to benefit directly from the development of the Alaska LNG Project; SB 138 requires the Department of Revenue to develop a plan and suggest legislation for these corporations to acquire ownership interests in the Project
	GOVERNMENT ENTITIES⁷⁷ <ul style="list-style-type: none"> Consistent with the Alaska State Constitution's policy to encourage the maximum use and development of its resources consistent with the public interest, there are a number of Alaska government entities whose purpose is to manage and promote the development of its lands
FEDERAL ENTITIES⁷⁸	OFFICE OF THE FEDERAL COORDINATOR <ul style="list-style-type: none"> Established by Congress in 2004 to help expedite/coordinate federal permitting for construction of Alaska natural gas pipelines Office coordinates with more than 20 federal agencies, the State of Alaska, tribal governments and other stakeholders, including the Project sponsors

Note: Pricing data as of January 2, 2015.

⁷² FactSet, Company and entity websites, SB 138.

⁷³ "Prudhoe Bay Report 2013," BP.

⁷⁴ "Point Thomson: Key gas field that's challenging to produce," Office of the Federal Coordinator, May 11, 2012.

⁷⁵ Includes North Slope Borough, Denali Borough Assembly, Kenai Chamber of Commerce, Fairbanks North Star Borough, Cook Inlet Region Citizens Advisory Council, Mat-Su Borough, Nikiski Community Council, among others.

⁷⁶ The amount to be deposited in the Fund is 20% of the revenue received from the State's royalty gas transported by the Alaska LNG Project, after payment of the constitutionally mandated 25% to the Alaska Permanent Fund.

⁷⁷ Includes Alaska State Pipeline Coordinators Office, Alaska Department of Fish and Game, Alaska Department of Natural Resources, Alaska Departments of Geology and Geophysical Survey, Alaska Railroad Corporation, Alaska Department of Environmental Conservation, among others.

⁷⁸ Also includes the Bureau of Land Management, DOE, Environmental Protection Agency, FERC, U.S. Army Corp of Engineers, U.S. Coast Guard, National Park Service, U.S. Fish and Wildlife Service, National Maritime Fisheries Service, among others.

D. Overview of Project Phases and Development Plan

The Project is currently in the Pre-FEED phase; the next key decision point (commencement of FEED) is planned for 2015/2016. The Project’s phases are outlined in the table below.^{79, 80}

	SELECTED ACTIVITIES	REQUIREMENTS TO PROCEED	SIZE
PRE-FEED (2014 – 2015)	<ul style="list-style-type: none"> ■ Refine engineering and Project concept ■ Evaluate preliminary business structure ■ Form preliminary financing plan ■ Perform environmental activities/technical data collection ■ File DOE export license <ul style="list-style-type: none"> ■ Completed July 21, 2014 ■ The Project requests an export of up to 20 MTPA of natural gas for 30 years 	<ul style="list-style-type: none"> ■ Government support secured ■ Viable technical option identified ■ Permits/land use arrangements in process ■ Potential for commercial viability assessed 	<ul style="list-style-type: none"> ■ Expected cost: \$400 million⁸¹ ■ Expected workforce: 400 – 500
FEED (2016 – 2018)	<ul style="list-style-type: none"> ■ Complete major Project engineering and design work ■ Finalize major commercial and EPC contracts ■ Finalize business structure ■ Secure financing arrangements 	<ul style="list-style-type: none"> ■ Government support secured ■ Permits, land use arrangements and construction financing secured ■ Key commercial agreements (e.g., individual gas/LNG sales and shipping arrangements) executed ■ EPC contracts executed ■ Commercial viability confirmed ■ FID 	<ul style="list-style-type: none"> ■ Expected cost: \$1.8 billion⁸¹ ■ Expected workforce: 500 – 1,500
EPC (2019 – 2023)	<ul style="list-style-type: none"> ■ Finalize engineering ■ Receive funds ■ Execute procurement plan ■ Complete construction ■ Prepare for operations 	<ul style="list-style-type: none"> ■ Construction of GTP, Pipeline and LNG Plant ■ Secure permanent financing ■ Secure operating permits 	<ul style="list-style-type: none"> ■ Expected cost: \$52.8 billion⁸¹ ■ Expected workforce: 9,000 – 15,000
OPERATIONS (2024+)	<ul style="list-style-type: none"> ■ Project produces 15 – 18 MTPA⁸² ■ Project revenues flow to owners based on Project ownership percentages 		<ul style="list-style-type: none"> ■ Expected permanent workforce: 1,000

⁷⁹ The Concept Selection phase ended in 2012.

⁸⁰ Project Overview with AGDC.

⁸¹ Based on total expected cost of \$55 billion (midpoint of \$45 – \$65 billion, in 2012 dollars).

⁸² DOE export license requests 20 MTPA.

E. Overview of Current Situation

Sizable and growing Asian demand for LNG, together with the potential for Alaska production, support the State's decision to pursue the development of Alaska's natural gas reserves. While the AKLNG Project has developed strong momentum, received numerous regulatory approvals and garnered widespread support, as with any project of its size, a number of risks exist, and the success of the Project will require careful planning and risk mitigation by the Project sponsors.

1. Alaska Market

According to the Project's DOE export application, the expected supply of natural gas reserves in Prudhoe Bay is more than sufficient to satisfy both in-State demand and the Project requirements for a 30-year export term at 20 MTPA.⁸³ This conclusion is based on the findings of various studies, including a report prepared by NERA Economic Consulting, and the AKLNG Project-commissioned DeGolyer and MacNaughton Report. The NERA Report estimates that approximately 47.5 Tcf of natural gas supply is necessary to meet estimated upstream lease operations fuel, Alaska in-State natural gas demand and export demand.⁸⁴ The DeGolyer and MacNaughton Report estimates Alaska total gas supply of 63.5 Tcf.⁸⁵

STATE OF ALASKA'S EXPECTED EXCESS GAS SUPPLY

CATEGORY	AMOUNT (Tcf)	
Total Estimated Reserves and Resources	63.5	
Upstream Lease Operations Fuel (2013 – 2052E)	(10.2)	} Total = 47.5 Tcf
In-state Use (2013 – 2052E)	(5.4)	
LNG Export Demand (i.e., 20 MTPA over 30-year LNG Export Term)	(31.9)	
Excess Gas Supply	16.0	

Sources: DeGolyer and MacNaughton Report, NERA Report.

DEMAND FOR ALASKA NATURAL GAS—DETAIL (Tcf)

		2013	2018E	2023E	2028E	2033E	2038E	2043E	2048E	Cumulative Total
Alaska Demand	Upstream Lease Operations Fuel	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	10.2
	In-State Use	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	5.4
LNG Export Demand		-	-	0.9	1.1	1.1	1.1	1.1	1.1	31.9
Total Natural Gas Demand		0.4	0.4	1.2	1.5	1.5	1.5	1.5	1.5	47.5

Source: NERA Report.

⁸³ AKLNG – U.S. DOE Export Application.

⁸⁴ "Socio-Economic Impact Analysis of Alaska LNG Project," NERA Economic Consulting, Prepared for Locke Lord LLP, June 19, 2014 ("NERA Report").

⁸⁵ DeGolyer and MacNaughton Report.

2. Import Markets

The AKLNG Project would likely export LNG to countries that are projected to have strong long-term demand for LNG, including Japan, South Korea, China and India. While these markets currently exhibit substantial LNG demand, several factors may limit the magnitude of this demand in the future, including import capacity limitations and development of domestic or regional energy resources.

a. Japan

Japan's limited domestic energy resources and position as a major player in international trade make the nation a prime market for LNG. Japan is the world's largest end market for LNG with 2013 imports of 88 MTPA (37% of global volume).⁸⁶ This particularly high level of demand, however, is a relatively new phenomenon, driven primarily by the country's shift in fuel mix after the meltdown of nuclear reactors at the Fukushima power plant and the subsequent shutdown of nearly all nuclear power plants in the country. Between 2010 and 2013, Japan's LNG imports increased 25% and, for the first eight months of 2014, the country imported 11.9 Bcf/d of LNG to fuel its power plants.⁸⁷

Japan's high LNG demand has driven an increase in the average cost of imports, from \$9/MMBtu before the Fukushima incident to a high of over \$18/MMBtu in 2012.⁸⁸ However, Japan's largest importers have started to negotiate contracts jointly and to use the country's status as a large importer of LNG to negotiate better pricing and mitigate future price increases.⁸⁹

Certain risks exist to Japan's future LNG demand, including a resumption of nuclear energy generation, import capacity limitations and other factors. In September 2014, Japan's Nuclear Regulation Authority approved the use of approximately 1.8 gigawatts ("GW") of nuclear energy generation that was previously shut down.⁹⁰ Moreover, Japan currently operates 30 LNG terminals with a total capacity of 185 MTPA, which exceeds current levels of demand. Finally, Japan's low electricity demand growth and increased penetration of solar energy may also limit future LNG demand growth.⁹¹

b. South Korea

South Korea is the second-largest LNG importer in the world with imports of 41 MTPA (17% of global volume) in 2013. The country has no international oil or natural gas pipelines and, as a result, imports 97% of its fuel by tanker shipments of oil and LNG. Although the country has 203 Bcf of

⁸⁶ IGU World LNG Report.

⁸⁷ "Japan," EIA, July 31, 2014.

⁸⁸ EIA.

⁸⁹ EIA.

⁹⁰ "Japan Nuclear Restart Weakens Oil and LNG Demand Incrementally," Energy Security Analysis, September 16, 2014.

⁹¹ "The Asian Quest for LNG in a Globalising Market," International Energy Agency, November 2014.

proven natural gas reserves, domestic gas production contributes less than 2% to its domestic energy consumption.⁹²

Certain risks could dampen South Korean LNG demand growth. KOGAS, the single-largest LNG buyer in the world, has a monopoly on domestic natural gas sales and deferred a number of LNG deliveries in November 2014 due to excess inventories of gas.⁹³ Moreover, KOGAS recently announced plans to sell down its equity stake in LNG Canada, a 12 MTPA LNG project, as it expects to purchase less natural gas than previously estimated.

c. China

China is the third-largest LNG importer in the world, with imports of 19 MTPA (8% of global volume) in 2013. Buoyed by growing LNG capacity (32 MTPA in 2013 vs. 6 MTPA in 2008) and economic growth, Chinese LNG demand is expected to grow significantly over the next decade.⁹⁴ Chinese natural gas usage is estimated to account for over 10% (approximately 60 MTPA) of the country's energy mix by 2020, compared to only 4% in 2010. Since China's coal market alone is currently seven times larger than the world LNG market, increased penetration of LNG in China could be a significant source of growth for exporters.⁹⁵

Certain risks could make Chinese LNG demand forecasts highly variable. China has begun to develop its own shale gas resources and is expected to boost domestic production by 65% to 6.8 Tcf/year in 2019 from its current level of 4.1 Tcf/year.⁹⁶ As a result, over half of incremental gas demand for the country could be met by domestic resources. Moreover, China imports gas from Central Asia and Myanmar, and has strengthened ties with Russian gas exporters after signing a \$400 billion gas supply agreement in May 2014. If these ties continue to strengthen, China could have access to a large source of pipeline-delivered natural gas, which would likely be more cost-effective than imported LNG. Given these factors, and despite growth in overall Chinese LNG demand, China's proportion of LNG as a percentage of its total energy supply is expected to decrease by 2025.⁹⁷

d. India

India is the fourth-largest LNG importer in the world, with imports of 13 MTPA (5% of global volume) in 2013. Due to limited infrastructure and low production of domestic natural gas, India increasingly depends on LNG to meet growing electricity demand. While natural gas contributes only 12% of the country's energy mix (compared to the world average of 23%), estimates suggest

⁹² "South Korea," EIA, April 1, 2014.

⁹³ "South Korea's Kogas to cut LNG imports in response to weaker local demand," Platts, November 20, 2014.

⁹⁴ "China," EIA, February 4, 2014.

⁹⁵ "Global LNG: Will New Demand and New Supply Mean New Pricing?" EY, March 19, 2013.

⁹⁶ "Medium-Term Gas Market Report," International Energy Agency, June 10, 2014.

⁹⁷ "The Asian Quest for LNG in a Globalising Market," International Energy Agency, November 2014.

that increased domestic gas-fired power generation and natural gas infrastructure could push Indian LNG demand to 27 MTPA by 2020.⁹⁸

Several factors could limit the growth of India's LNG demand. The country has access to abundant coal reserves, which may serve as an inexpensive substitute for baseload power generation. Preferential allocation of domestic gas resources could limit the market potential for LNG going forward. In addition, the level of LNG imports depends heavily on the expansion of current regasification capabilities, as India's current regasification capacity is limited to 21 MTPA.⁹⁹

3. Partner Roles and Commitments

The State is partnering with a number of energy companies in the development of the Project. The table below summarizes the roles of each partner as well as their stake in the Project.¹⁰⁰

	ILLUSTRATIVE PROJECT OWNERSHIP (%)	ROLE
STATE OF ALASKA	■ 25% ¹⁰¹	■ Constructive facilitation of the Project ¹⁰²
EXXON	■ 25% ¹⁰¹ ■ Represents 3% of current Exxon enterprise value ¹⁰³	■ Concept and integration team leader ■ Management committee member
BP	■ 25% ¹⁰¹ ■ Represents 9% of current BP enterprise value ¹⁰³	■ Commercial and producing fields team leader ■ Management committee member
CONOCO	■ 25% ¹⁰¹ ■ Represents 13% of current Conoco enterprise value ¹⁰³	■ LNG Plant team leader ■ Management committee member
TRANSCANADA	■ 0% ¹⁰¹	■ Significant resource commitment ■ Management committee member

Source: Heads of Agreement.

⁹⁸ BCG Report.

⁹⁹ BCG Report.

¹⁰⁰ TransCanada agreed to be responsible for 60% – 100% of the State's upfront capital costs related to construction of the GTP and Pipeline in exchange for the State's agreement to pay a tariff on each unit of natural gas moved by the Pipeline. The contracted arrangement between TransCanada and the State is further described below in Section IV.F.

¹⁰¹ 25% ownership figure is illustrative. Ultimate Project ownership percentage will depend, for example, on each entity's share of Project gas, among other factors, and may vary from this amount.

¹⁰² May include, for example, use of eminent domain rights, approving funding, supporting federal export applications, permitting, appropriations for in-state infrastructure necessary for the Project as well as drafting, introducing and supporting necessary legislation, etc.

¹⁰³ Based on 25% of expected Project ownership costs of \$13.7 billion (midpoint).

4. Key Project Milestones Achieved to Date

Since the Project started to take its current form in Fall 2011, a number of milestones have been achieved that have allowed for further advancement. Key milestones to date are presented below.

PROJECT MILESTONES

DATE	EVENT DESCRIPTION
October 2011	■ Alaska's Governor requests that Exxon, BP, Conoco and TransCanada work together to evaluate the economic feasibility of a project to address in-State gas needs and serve LNG export markets abroad
March 30, 2012	■ Chief Executives of Exxon, Conoco and BP write to former Governor Parnell regarding their initial work with TransCanada to assess the viability of an Alaska LNG Project
October 1, 2012	■ Exxon, Conoco, BP and TransCanada outline the key aspects of the AKLNG Project, including expected costs and a development timeline
October 7, 2013	■ Exxon, Conoco, BP and TransCanada identify Nikiski as the site for the proposed liquefaction port and export terminal
January 14, 2014	■ The State, Exxon, Conoco, BP and TransCanada execute a Heads of Agreement and an MOU outlining terms for participation in the AKLNG Project, including the State's equity stake in the Project
July 2, 2014	■ The State, Exxon, Conoco, BP and TransCanada sign a formal commercial agreement for the Project, beginning the Pre-FEED phase
July 18, 2014	■ AKLNG Project applies for authorization from the DOE to ship LNG to countries that do and do not currently have free trade agreements with the U.S.
September 5, 2014	■ AKLNG Project submits request to FERC to begin pre-filing process
October 1, 2014	■ AKLNG Project files two reports with FERC that are required to initiate the environmental impact review
November 21, 2014	■ DOE authorizes LNG exports from the Project to countries that currently have free trade agreements with the U.S.

Sources: "Alaska North Slope Natural Gas Line Project History," Office of the Federal Coordinator, March 4, 2014 and Office of the Federal Coordinator and Press Releases.

5. Risks

The AKLNG Project presents a number of risks, including potential for cost overruns during construction and commodity price risk. The table below describes various identified risks and potential mitigants that are typical of large-scale LNG projects.

	DESCRIPTION OF RISK	POTENTIAL MITIGANTS
DEVELOPMENT	<ul style="list-style-type: none"> Project is abandoned following development stage (and associated expenditures) Investment required is too large/concentrated (e.g., represents ~3%, 9% and 13% of Exxon, BP and Conoco's enterprise value, respectively) 	<ul style="list-style-type: none"> Ongoing/iterative assessment of Project feasibility, including size of ownership interests
COST OVERRUNS	<ul style="list-style-type: none"> Project encounters cost overruns during construction of GTP, Pipeline and/or LNG Plant 	<ul style="list-style-type: none"> EPC contracts with appropriate risk transfer provisions Third-party contracts with partners (e.g., TransCanada) that are positioned/able to share risk Ongoing/iterative assessment of Project feasibility prior to construction
COMMERCIAL	<ul style="list-style-type: none"> Project is unable to achieve favorable commercial terms (or terms required to make the Project viable) 	<ul style="list-style-type: none"> In-depth market analysis State participation in Project Partner/sponsor marketing strategy Ongoing/iterative assessment of Project feasibility
REGULATORY	<ul style="list-style-type: none"> Project fails to receive required regulatory approvals (e.g., FERC) Project fails to receive DOE export license Project is delayed as a result of litigation 	<ul style="list-style-type: none"> Early stakeholder outreach and communications strategy Regulatory concessions and iteration of Project plan Political support and strategy
COMMODITY PRICE	<ul style="list-style-type: none"> Expected LNG prices too low to support Project economics Realized LNG prices much lower than budgeted levels 	<ul style="list-style-type: none"> Fixed- or partially fixed-price long-term contracts prior to construction Decoupling of price from traditional indices Hedging strategy State participation in Project Take-or-pay contracts Ongoing/iterative assessment of Project feasibility, including with respect to commodity price scenarios
OVER-SUPPLY/COMPETING PROJECTS	<ul style="list-style-type: none"> Market saturation is reached in global LNG market Competing projects (e.g., those in the Lower 48, Canada, Latin America, Australia, etc.) possess more favorable characteristics than Alaska LNG Project 	<ul style="list-style-type: none"> In-depth market analysis Take-or-pay contracts Ongoing/iterative assessment of Project feasibility, including with respect to commodity price scenarios
DEMAND	<ul style="list-style-type: none"> Demand for LNG decreases as a result of a variety of factors (e.g., revival of nuclear power industry in Japan, fuel switching in other markets) 	<ul style="list-style-type: none"> In-depth market analysis Take-or-pay contracts Flexibility in delivery of LNG

F. Analysis of Alaska's MOU with TransCanada

The State has entered into an agreement with TransCanada (the MOU) that outlines the parties' relationship with respect to the development and management of the GTP and Pipeline. The MOU transfers financing responsibilities for and control of the State's equity share in the GTP and Pipeline to TransCanada. Further, the MOU details TransCanada's terms of service for transporting Alaska's gas share via the GTP and Pipeline. Selected facts and observations regarding the MOU are summarized in the table below.

ANALYSIS OF TRANSCANADA MOU

FACTS	
①	<p>The State transfers financing responsibilities for and control of the State's equity share in the GTP and Pipeline to TransCanada</p> <ul style="list-style-type: none"> ■ AGDC has the option to purchase up to a 40% interest in the partnership distributions associated with the GTP and Pipeline prior to the FEED phase of the Project (circa December 31, 2015) <ul style="list-style-type: none"> ■ Partnership distributions would be subject to TransCanada control on budgetary factors (e.g., timing) ■ TransCanada is responsible for between 60% and 100% (depending on exercise of the option) of the State's upfront capital costs related to GTP and Pipeline construction
②	<p>The State commits to 25-year FTSA with TransCanada</p> <ul style="list-style-type: none"> ■ The State pays TransCanada a tariff for each unit of natural gas moved by the GTP and Pipeline, based on capital structure and return criteria: <ul style="list-style-type: none"> ■ 75/25 debt-to-equity ratio for rate purposes¹⁰⁴ ■ Fixed TransCanada ROE of ~12% and cost of debt of ~5%¹⁰⁵
③	<p>If either the State or TransCanada terminates the agreement at any point before FID, the State is responsible for reimbursing TransCanada's planning and development costs (including internal development costs¹⁰⁶) and interest; however, the State would maintain the option to proceed with the Project on its own¹⁰⁷</p> <ul style="list-style-type: none"> ■ TransCanada may terminate the contract if it does not secure debt financing on terms it finds satisfactory within three months from FID
OBSERVATIONS	
①	<p>The State is responsible for funding an estimated \$13.7 billion without TransCanada participation vs. \$7.0 billion with TransCanada</p> <ul style="list-style-type: none"> ■ The State reduces its capital requirements throughout Project planning, design and development <ul style="list-style-type: none"> ■ Exposes the State to 13% – 18% of the total projected upfront Project costs; allows the State to retain 25% of the gas share in the operational Project ■ The State would still be responsible for repaying TransCanada's upfront investment via the return of capital mechanism established in the tariff ■ Shifts Project management responsibilities to TransCanada, but reduces the State's operational control ■ Potential complexities associated with TransCanada involvement in other projects
②	<p>Reduces the State's share of revenues by \$200 – \$360 million per year (depending on exercise of the option)</p> <ul style="list-style-type: none"> ■ 75/25 debt-to-equity ratio for rate-making purposes reduces the State's tariff, seemingly favorable debt-to-equity ratio for the State, relative to that of similar regulated ratebase arrangements
③	<p>The State retains virtually all Project risk under the MOU</p> <ul style="list-style-type: none"> ■ Contract termination by either party results in the State reimbursement of TransCanada's planning and development costs ■ While the State is temporarily shielded from cost overruns during planning and development, the State ultimately bears these costs via the tariff, which provides a 100% return of capital (as well as a return on capital) to TransCanada

Source: Alaska MOU with TransCanada and Black & Veatch Model, dated February 2014.

¹⁰⁴ This capital structure commences on the second anniversary of the in-service date, and continues through the term of the FTSA. During development/construction and expansions/maintenance, Project capital structure is 70% debt and 30% equity.

¹⁰⁵ The agreed-upon ROE and cost of debt are each subject to a "Rate Tracker Differential", amounting to the increase or decrease in the 30-year U.S. Treasuries yield at FID relative to such yield at the effective date of the MOU.

¹⁰⁶ Includes ~\$70 million incurred on the Alaska portion of the AGIA project.

¹⁰⁷ Should either the State or TransCanada terminate the MOU before FID, the State is responsible for reimbursing TransCanada's development costs. In the case where the State terminates or where the Alaska State Legislature does not ratify either the MOU or the FTSA, then the State must reimburse TransCanada development costs plus interest of 7.1% (i.e., the Allowance for Funds Used During Construction ("AFUDC") amount).

G. Overview of Total Project and Alaska-Specific Economics¹⁰⁸

The AKLNG Project has an expected overall cost of \$45 – \$65 billion (midpoint estimate of \$55 billion), while the State’s portion (assuming 25% participation) is expected to cost \$11.3 – \$16.3 billion (midpoint estimate of \$13.7 billion¹⁰⁹). The participation of the State and the producers is premised upon achieving an adequate return on this upfront investment through Project revenues during operations.¹¹⁰

1. Project Investment Timeline

As described earlier, the Pre-FEED phase of the Project is expected to cost ~\$0.4 billion, the FEED phase of the Project is expected to cost ~\$1.8 billion and the EPC phase of the Project is expected to cost ~\$52.8 billion.¹¹¹ The table below sets forth the expected annual investment for the various facilities of the Project during each phase.

TOTAL PROJECT INVESTMENT (\$ IN MILLIONS)										
	PRE-FEED		FEED			EPC				
	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E
GTP	\$43	\$88	\$184	\$216	\$139	\$1,659	\$2,847	\$2,933	\$2,417	\$1,867
Pipeline	43	88	184	216	139	1,990	3,417	3,519	2,900	2,240
LNG Plant	57	117	245	288	186	3,815	6,549	6,746	5,558	4,294
Total	\$142	\$292	\$613	\$721	\$464	\$7,464	\$12,814	\$13,198	\$10,875	\$8,401
Phase Total	\$434		\$1,798			\$52,752				

Source: Black & Veatch Model, dated February 2014.
 Note: Figures are presented in nominal dollars.

The Project is currently in the Pre-FEED phase, which is expected to last through 2015/2016. At that point, the State can decide to exit the Project, or to move into the FEED phase. The FEED phase is expected to last until 2018, at which point the State can decide to exit the Project. After FID, the Project advances into the EPC phase.¹¹² The figure below illustrates the State’s decision points at various phases throughout the Project timeline.

ILLUSTRATIVE PROJECT MILESTONES AND DECISION POINTS¹¹³



¹⁰⁸ Project Overview with AGDC. Project costs in this section are shown in 2012 dollars, unless otherwise noted.
¹⁰⁹ Midpoint estimate of \$7.0 billion if TransCanada MOU remains in effect. Further detail regarding the State’s financing need is presented in Section VI.A.
¹¹⁰ Net of any operating costs, including tariffs.
¹¹¹ Based on Project cost midpoint of \$55 billion.
¹¹² Should either the State or TransCanada terminate the MOU before FID, the State is responsible for reimbursing TransCanada’s development costs. In the case where the State terminates or where the Alaska State Legislature does not ratify either the MOU or the FTSA, then the State must reimburse TransCanada development costs plus interest of 7.1% (i.e., the AFUDC amount).
¹¹³ “Alaska LNG Project cash flow chart,” Black & Veatch, March 2014.

2. Project Revenues

The primary components of Project revenue for the State would be as follows:¹¹⁴

Royalty

As an owner of the land on which the Project's natural gas is produced, the State is entitled to a royalty payment based on the total gas production of the Project. The State has the option to take its royalty payment in the form of cash or in kind (i.e., in units of natural gas).¹¹⁵ As provided for by Alaska law and as set forth in the Heads of Agreement, the State has conditionally committed to taking its full royalty in kind (currently anticipated to be 12.5% of total gas production of the Project at the Prudhoe Bay facility¹¹⁶), depending on the satisfaction of key fiscal and contractual concerns.¹¹⁷

Production Tax

In addition to a royalty on production, the State is entitled to a tax on production. Gas that is produced within the State is subject to a tax as it leaves the ground. The tax does not apply to the royalty gas that is discussed above.¹¹⁸ Similar to the royalty, the production tax may be delivered either in cash or in kind, and the State has given the option to each of the producers to elect which form of delivery will be used. If a producer exercises the option to pay in kind, the State would receive a fixed percentage of each producer's taxable gas from the Project (currently anticipated to be ~13%). Otherwise, the State will receive its production tax in cash.¹¹⁵

Property Tax

Additionally, the State receives revenues in the form of property taxes. Property tax is charged against any owners of property associated with the Project (e.g., land, Project facilities). In certain cases, local municipalities may also levy a property tax; however, such amount would be credited toward a property owner's State property tax obligation.¹¹⁹

State Corporate Income Tax

The final source of revenue for the State is corporate income tax, which would be levied on the taxable income of the various corporations associated with the Project.

¹¹⁴ The State, via AGDC, could also potentially be entitled to tariffs in the event that AGDC sells capacity on Project equipment to third parties in the future.

¹¹⁵ Heads of Agreement.

¹¹⁶ Royalty percentage at Point Thomson facility varies with different leases.

¹¹⁷ "Observations on Heads of Agreement," Black & Veatch, March 25, 2014.

¹¹⁸ Fall 2013 Revenue Sources Book.

¹¹⁹ Fall 2013 Revenue Sources Book.

a. State Revenue Projections

The tables and charts below set forth the current projections for the Project's revenue sources and cash flows.^{120, 121} These projections contemplate two scenarios: one in which the State continues in its partnership with TransCanada ("TransCanada Partnership Scenario") and one in which the State invests in the Project on its own ("State Go-it-Alone Scenario"). These scenarios were chosen as "bookends" for the analysis, given that in the State Go-it-Alone Scenario, the State is fully responsible for financing its 25% equity interest in the Project and, in the TransCanada Partnership Scenario, the State receives the largest TransCanada financial participation contemplated by the MOU (i.e., assumes that the Alaska 40% buyback option is not exercised).

STATE OF ALASKA CASH FLOWS—25% EQUITY IN PROJECT (\$ IN MILLIONS)

	2014E	2015E	2017E	2019E	2021E	2023E	2025E	2027E	2029E	2031E	2033E	2035E	2037E	2039E	2041E	2043E
TransCanada Partnership Scenario																
Unrestricted Royalty in Kind*	\$0	\$0	\$0	\$0	\$0	\$0	\$934	\$941	\$979	\$1,017	\$1,056	\$1,098	\$1,143	\$1,193	\$1,248	\$1,813
Restricted Royalty in Kind**	0	0	0	0	0	0	320	322	335	348	362	376	391	408	427	621
Total Royalty in Kind	\$0	\$0	\$0	\$0	\$0	\$0	\$1,253	\$1,262	\$1,314	\$1,365	\$1,418	\$1,473	\$1,534	\$1,601	\$1,675	\$2,434
Production Tax (Tax in Kind)	(30)	(32)	(36)	(74)	(383)	(421)	875	1,080	1,039	981	1,005	1,157	1,113	514	986	993
Upstream Corporate Income Tax	1	1	1	2	12	11	166	170	194	209	220	245	254	275	292	379
Midstream Corporate Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0	454	530	627
Upstream Property Tax***	4	6	12	23	73	122	167	172	164	153	140	126	135	192	177	1,018
Midstream Property Tax***	0	0	0	0	0	84	75	66	58	49	40	31	22	13	4	0
Project Ownership (LNG Plant)	(4)	(9)	(22)	(286)	(506)	(322)	451	437	422	407	390	372	353	333	311	287
Total	(\$29)	(\$34)	(\$45)	(\$335)	(\$805)	(\$525)	\$2,986	\$3,188	\$3,190	\$3,162	\$3,213	\$3,405	\$3,411	\$3,381	\$3,975	\$5,737
State Go-it-Alone Scenario																
Unrestricted Royalty in Kind*	\$0	\$0	\$0	\$0	\$0	\$0	\$983	\$990	\$1,028	\$1,066	\$1,105	\$1,147	\$1,192	\$1,242	\$1,298	\$1,864
Restricted Royalty in Kind**	0	0	0	0	0	0	336	339	352	365	378	393	408	425	444	638
Total Royalty in Kind	\$0	\$0	\$0	\$0	\$0	\$0	\$1,319	\$1,329	\$1,380	\$1,431	\$1,484	\$1,540	\$1,600	\$1,668	\$1,743	\$2,502
Production Tax (Tax in Kind)	(30)	(32)	(36)	(74)	(383)	(421)	936	1,141	1,100	1,042	1,066	1,219	1,175	576	1,048	1,056
Upstream Corporate Income Tax	1	1	1	2	12	11	166	170	194	209	220	245	254	275	292	379
Midstream Corporate Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0	407	465	551
Upstream Property Tax***	4	6	12	23	73	122	167	172	164	153	140	126	135	192	177	1,018
Midstream Property Tax***	0	0	0	0	0	0	80	71	62	53	44	35	27	18	9	0
Project Ownership (GTP, Pipeline, LNG Plant)	(11)	(22)	(54)	(560)	(990)	(630)	874	851	826	800	772	745	717	688	659	634
Total	(\$36)	(\$47)	(\$77)	(\$608)	(\$1,289)	(\$918)	\$3,542	\$3,734	\$3,725	\$3,687	\$3,727	\$3,910	\$3,908	\$3,823	\$4,392	\$6,139

Source: Black & Veatch Model, dated February 2014, as adjusted by the State.

Note: Figures are presented in nominal dollars. State revenue sources and funds to be discussed in greater detail in Section V.A.

* Reflects funds available to the State as General Fund Unrestricted Revenue.

** Reflects 25.0% and 0.5% of Total Royalty in Kind allocated to the Permanent Fund and the School Fund, respectively.

*** Reflects estimated property tax cash flows to the State, net of payments to local municipalities.

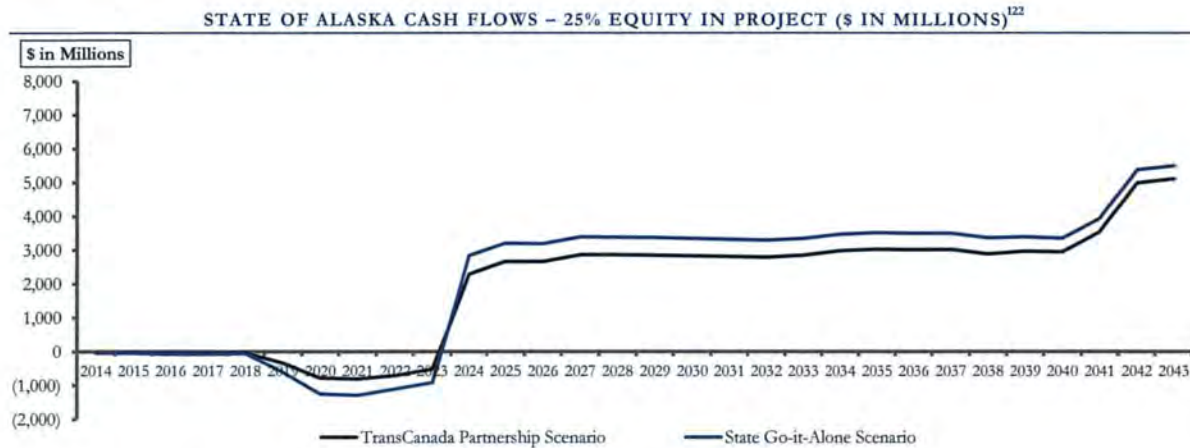
As can be seen above, in the TransCanada Partnership Scenario, the State makes a relatively lower upfront investment, but receives lower revenues during operations. In the State Go-it-Alone Scenario, the State must make a greater upfront investment, but is entitled to greater revenues during operations.

¹²⁰ Cash flows are presented on a levered basis (i.e., cash flows to the State after projected debt service payments) assuming an illustrative 70% debt/30% equity Project capitalization and a 5% cost of debt.

¹²¹ Projections are based on Black & Veatch Model, dated February 2014, as adjusted by the State. Projections contemplate an LNG price of ~\$16/MMBtu in nominal 2024 dollars; variations in the future price of LNG (e.g., as a result of declining oil prices, LNG oversupply, etc.) can have a significant impact on Project revenues, particularly the royalty and production tax in kind.

Additionally, cash flows have been projected for 20 years; however, the Project could potentially remain in operation past this period, which could have the benefit of incremental cash flows to those shown.

Additionally, these cash flows have the benefit of being relatively stable during operation, with the added benefit of potential increases toward the latter stages of operation. These relationships are also illustrated in the following graph.



3. Project Operating Expenses

Included in the Project cash flows highlighted above are operating expenses, which are subtracted from revenues to determine the cash available for the State to provide a return on the debt and equity used to finance the upfront investment in the Project. These include tariffs, shipping costs and operations and maintenance (“O&M”) expenses.

a. Tariffs

The sellers of the Project’s LNG would be required to make tariff payments to the owners of the various facilities associated with bringing the LNG to market (i.e., the GTP, Pipeline and LNG Plant). The tariffs are structured such that (given expected Project volumes) the owner of the Project facilities would receive a predetermined rate of return on the initial investment.¹²³

As was discussed in greater detail in Section IV.F, the State has agreed to pay a tariff to TransCanada in exchange for providing the financing for the State’s 25% portion of the GTP and Pipeline.¹²³ The structure of the MOU allows for a 40% buy-back option, wherein AGDC would become a partner of TransCanada and thereby be entitled to a share of the proceeds from the State’s tariff.¹²⁴

If the State terminates its MOU with TransCanada and instead decides to fully finance its 25% portion of the GTP and Pipeline (in addition to its 25% portion of the LNG Plant), the State would be responsible for paying cost-based tariffs; however, the State would need to make the upfront investment required to construct the facilities.

¹²² Black & Veatch Model, dated February 2014, as adjusted by the State.

¹²³ Actual tariffs are calculated based on a regulated ratebase formula, wherein debt and equity capitalization percentage and associated rates of return for each facility are agreed upon in advance. The levelized tariff is then calculated based on expected volumes, such that the agreed-upon rates of return are met.

¹²⁴ Only pass-through costs (i.e., no return component).

b. Shipping Costs

The sellers of the Project’s LNG may be responsible for paying the shipping costs associated with transporting natural gas from the marine terminal in Alaska to regasification terminals overseas.¹²⁵ Shipping costs are dependent on factors such as global shipping capacity and the price of fuel.

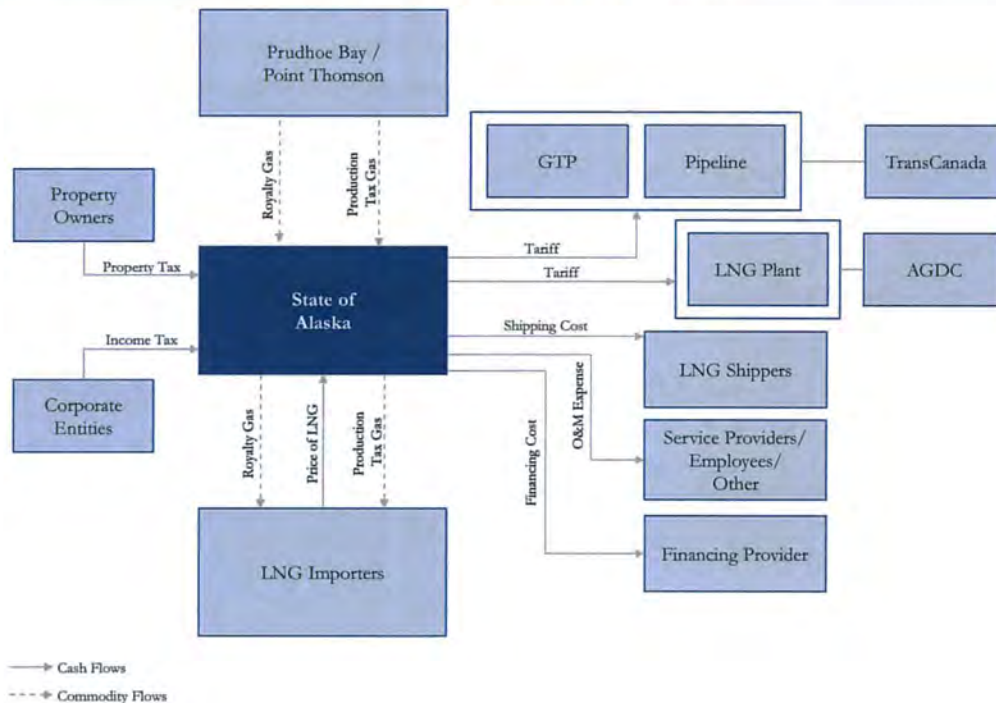
c. O&M Expenses

While the Project is in operation, various expenses would be incurred in order to, among other things, maintain equipment, pay employees and operate the Project’s facilities. As an owner of the Project, the State would be required to pay its portion of these expenses.

4. Flow of Funds

The Project revenues and costs discussed involve a number of parties; the following chart illustrates the “flow of funds” between these parties.¹²⁶

ILLUSTRATIVE FLOW OF FUNDS¹²⁷



¹²⁵ Under certain arrangements, the buyer of LNG could potentially be responsible for paying shipping costs.

¹²⁶ Illustration assumes the State takes royalty and production tax in kind and pursues the TransCanada Partnership Scenario. Note that O&M expenses paid by the State would likely be facilitated via AGDC.

¹²⁷ “State participation in AK LNG Project, Presentation to the House Finance Committee,” Black & Veatch, April 2014, modified by Lazard.

5. Economic Analysis

The State expects to receive Project cash flows, as presented above in Section IV.G.2.a. An indicator of the Project’s viability and overall economic benefit is its net present value (“NPV”), that is, the value of the Project’s forecasted future cash flows discounted to today. Typically, if the NPV of a project is positive, it is considered economically viable, and vice versa. An unlevered discounted cash flow valuation analysis is a method of determining NPV that discounts unlevered free cash flows (i.e., cash flows that are available to all debt and equity investors) using a discount rate that reflects the overall risk associated with the projected cash flows. To arrive at unlevered free cash flows from the levered cash flows presented earlier, restricted revenues are excluded, and debt principal repayment and debt interest payments are added back.¹²⁸ The discount rate that is applied to these unlevered free cash flows is determined based on the perceived riskiness of the Project’s cash flows; the analysis below assumes an 8% discount rate for illustrative purposes.

Additionally, analysis can be performed to determine the sensitivity of the Project’s NPV to changing variables (e.g., the discount rate, Project revenues¹²⁹ and Project construction costs). This sensitivity analysis is presented below.

UNLEVERED DISCOUNTED CASH FLOW VALUATION ANALYSIS (\$ IN MILLIONS)

NPV Sensitivity Analysis—TransCanada Partnership Scenario

		PROJECT REVENUE VARIATION					CONSTRUCTION COST VARIATION						
		(10.0%)	(5.0%)	0.0%	5.0%	10.0%			10.0%	5.0%	0.0%	(5.0%)	(10.0%)
DISCOUNT RATE	6.0%	\$15,380	\$15,965	\$16,550	\$17,135	\$17,720	\$16,108	\$16,329	\$16,550	\$16,771	\$16,992		
	7.0%	12,369	12,853	13,337	13,821	14,305	12,926	13,131	13,337	13,543	13,749		
	8.0%	9,947	10,349	10,751	11,154	11,556	10,368	10,560	10,751	10,943	11,135		
	9.0%	7,994	8,329	8,664	8,999	9,334	8,307	8,485	8,664	8,842	9,021		
	10.0%	6,413	6,693	6,973	7,253	7,532	6,640	6,806	6,973	7,139	7,306		

NPV Sensitivity Analysis—State Go-it-Alone Scenario

		PROJECT REVENUE VARIATION					CONSTRUCTION COST VARIATION						
		(10.0%)	(5.0%)	0.0%	5.0%	10.0%			10.0%	5.0%	0.0%	(5.0%)	(10.0%)
DISCOUNT RATE	6.0%	\$16,916	\$17,537	\$18,157	\$18,778	\$19,398	\$17,282	\$17,720	\$18,157	\$18,595	\$19,033		
	7.0%	13,279	13,793	14,307	14,821	15,335	13,492	13,899	14,307	14,714	15,121		
	8.0%	10,370	10,797	11,224	11,651	12,078	10,465	10,845	11,224	11,603	11,983		
	9.0%	8,038	8,394	8,751	9,107	9,463	8,043	8,397	8,751	9,104	9,458		
	10.0%	6,166	6,464	6,762	7,060	7,358	6,102	6,432	6,762	7,092	7,422		

Note: Analysis presented above is preliminary and illustrative in nature. Elements of the analysis, including the Project cash flows, discount rate, etc., will continue to evolve over time as a result of multiple factors (e.g., market treatment of similar LNG projects).

¹²⁸ Given that restricted revenues are required to flow to the Permanent Fund and the School Fund, they are not available to investors. Principal repayments and interest payments must be added back because these are payments that are specific to debt investors, whereas the unlevered free cash flow analysis is meant to examine cash flows available to any investor.

¹²⁹ Variations in Project revenues (royalty/production tax) are analyzed to illustrate the impact of variances in contracted gas prices from those forecasted to be received during Project operation (e.g., as a result of declining oil prices, LNG oversupply, etc.).

At an illustrative 8.0% discount rate and assuming no variations from currently forecasted revenues and construction costs, the expected NPV in the TransCanada Partnership Scenario would be ~\$10.8 billion and the expected NPV in the State Go-it-Alone Scenario would be ~\$11.2 billion. Given the State's higher exposure to construction risk and associated reliance on the Project's revenues in the State Go-it-Alone Scenario, changes in these variables have a greater impact on NPV.

V State of Alaska Financial Overview

V. State of Alaska Financial Overview

Alaska's present day reliance on oil revenues, combined with declining oil production forecasts, suggest that a new revenue source would help Alaska maintain its strong fiscal position. According to State projections, Alaska oil output is expected to decrease materially over the next ten years. Additionally, historically-low oil prices are placing further pressure on the State's budget. Absent other changes in the State's revenue sources, these trends may potentially have a negative impact on Alaska's balance sheet, credit rating and bonding capacity.

A. Budget

1. Projections

Alaska's finances are highly dependent on oil revenue. In FY 2014, oil revenues accounted for 88% of the State's unrestricted revenue (i.e., revenue used to fund the State's general expenses).¹³⁰ Accordingly, the State's financial projections are heavily dependent on oil production and price assumptions over the forecast period. The State's current projections reflect its goal of diversifying its revenue base away from oil to include revenue from natural gas (including increased production in Cook Inlet). Currently, the State projects that it can fund its budget without incremental natural gas revenue until 2023,¹³¹ approximately when the Project would be expected to come online.¹³²

The State's Office of Management and Budget ("OMB") addresses this issue in its 10-Year Plan, which has the stated objectives to: (1) balance the State budget between sources and uses of funds, (2) provide for essential State services and (3) protect Alaska's economic stability. To mitigate exposure to resource fluctuations, OMB proposes careful management of its primary reserve accounts, the Constitutional Budget Reserve Fund ("CBRF") and Statutory Budget Reserve Fund ("SBRF"). Accordingly, the CBRF and SBRF are drawn on to balance the budget in the event of revenue shortfalls and are replenished in the event of revenue surpluses.

Given current forecasts, the State projects that it will run a deficit over the next 10 years (i.e., it will draw on the SBRF and/or the CBRF in each of those years). The combined current value of the CBRF and SBRF¹³³ of ~\$15.8 billion is projected to drop to ~(\$1.7) billion by 2024, fully depleting the SBRF and CBRF and creating a fund deficit; however, a new revenue source such as natural gas could allow the State to replenish its reserve funds while preparing it for future resource fluctuations.

The State also uses a variety of mechanisms intended to protect Alaska's fiscal stability.¹³⁴ For example, the Permanent Fund dividend (i.e., the annual payment made to Alaska citizens) is based on a trailing average of the current plus previous four years' Fund Statutory Net Income, thereby

¹³⁰ Fall 2014 Revenue Sources Book.

¹³¹ The State projects that it will fully deplete its reserve funds sometime between FY 2022 and FY 2023.

¹³² "Executive Summary FY 2015 10-Year Plan," Alaska Office of Management and Budget, December 12, 2013 ("OMB 10-Year Plan").

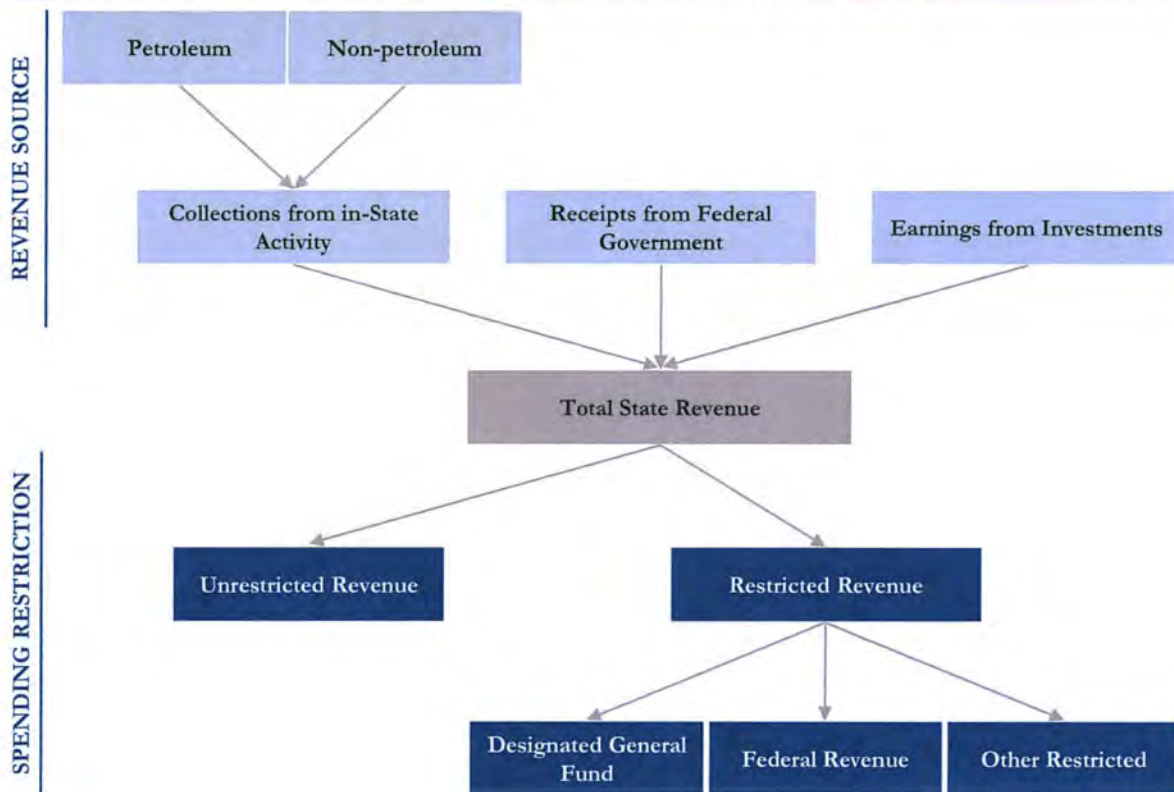
¹³³ As of FY 2014.

¹³⁴ OMB 10-Year Plan.

controlling for broad economic swings.¹³⁵ The State also funds programs in advance when appropriate, helping to set aside funding for vital programs, and safeguarding them in the event of a subsequent deficit.¹³⁶

In general, the State projects revenue based on where it comes from and how it can be used.¹³⁷ The State’s revenue can come from funds collected from in-State activities (categorized as petroleum and non-petroleum), funds received from the Federal Government, and interest and payments earned on assets owned by the State. The revenue is then categorized based on how it can be used: as unrestricted revenue or as restricted revenue. The following diagram illustrates how the State characterizes its revenues.

STATE OF ALASKA REVENUE ALLOCATION



Source: Fall 2014 Revenue Sources Book.

¹³⁵ “How the PFD Amount is Calculated,” Alaska Permanent Fund Corporation.

¹³⁶ OMB 10-Year Plan.

¹³⁷ Fall 2014 Revenue Sources Book.

V. STATE OF ALASKA FINANCIAL OVERVIEW

The State's current 10-year revenue projections based on these allocations are presented below.

STATE OF ALASKA REVENUE FORECAST BY CATEGORY (\$ IN MILLIONS)

	FY 2015E	FY 2016E	FY 2017E	FY 2018E	FY 2019E	FY 2020E	FY 2021E	FY 2022E	FY 2023E	FY 2024E
Unrestricted Revenue										
Unrestricted General Fund Revenue										
Petroleum Revenue	\$2,019	\$1,636	\$3,070	\$3,678	\$4,175	\$4,197	\$3,948	\$3,858	\$3,823	\$3,725
Non-petroleum Revenue	502	528	539	550	554	561	569	572	583	590
Investment Revenue	30	32	48	63	79	95	111	126	142	158
Federal Revenue	0	0	0	0	0	0	0	0	0	0
Total Unrestricted General Fund Revenue	\$2,552	\$2,197	\$3,657	\$4,292	\$4,808	\$4,853	\$4,628	\$4,556	\$4,548	\$4,473
Total Unrestricted Revenue	2,552	2,197	3,657	4,292	4,808	4,853	4,628	4,556	4,548	4,473
<i>Memo: Petroleum Revenue as a % of Total Unrestricted Revenue</i>	79%	75%	84%	86%	87%	87%	85%	85%	84%	83%
Restricted Revenue										
Designated General Fund Revenue										
Non-petroleum Revenue	\$323	\$322	\$326	\$326	\$325	\$325	\$325	\$325	\$325	\$324
Investment Revenue	20	36	36	36	36	36	36	36	36	36
Total Designated General Fund Revenue	\$344	\$358	\$362	\$362	\$361	\$361	\$361	\$361	\$360	\$360
Federal Revenue										
Petroleum Revenue	\$5	\$5	\$5	\$5	\$5	\$5	\$5	\$5	\$5	\$5
Federal Receipts	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126	3,126
Total Federal Revenue	\$3,131	\$3,131	\$3,131	\$3,131	\$3,131	\$3,131	\$3,131	\$3,131	\$3,131	\$3,131
Other Restricted Revenue										
Petroleum Revenue	\$513	\$466	\$677	\$701	\$723	\$690	\$645	\$600	\$580	\$560
Non-petroleum Revenue	229	230	231	232	233	235	236	237	238	240
Investment Revenue	3,319	3,537	3,438	3,368	3,332	3,245	3,233	3,210	3,184	3,180
Total Other Restricted Revenue	\$4,061	\$4,233	\$4,346	\$4,301	\$4,288	\$4,170	\$4,113	\$4,047	\$4,002	\$3,980
Total Restricted Revenue	7,536	7,722	7,839	7,794	7,781	7,662	7,605	7,539	7,494	7,471
Total State Revenue	\$10,088	\$9,919	\$11,496	\$12,086	\$12,589	\$12,515	\$12,233	\$12,095	\$12,042	\$11,945

Source: Fall 2014 Revenue Sources Book.

Additionally, the following table presents the State's projected uses of its unrestricted revenues, including the drawdown of the SBRF and CBRF, as mentioned above.

PROJECTED USES OF STATE OF ALASKA UNRESTRICTED REVENUES (\$ IN MILLIONS)

	FY 2014	FY 2015E	FY 2016E	FY 2017E	FY 2018E	FY 2019E	FY 2020E	FY 2021E	FY 2022E	FY 2023E	FY 2024E
Oil Price and Production											
Fall 2014 Forecast ANS West Coast (\$ per barrel)	\$107.57	\$76.31	\$66.03	\$93.18	\$102.81	\$112.00	\$117.36	\$121.14	\$123.87	\$129.04	\$134.39
Fall 2014 Forecast ANS Production (MMBD)	0.531	0.510	0.524	0.534	0.503	0.473	0.436	0.400	0.369	0.343	0.315
Revenue vs. Spending											
Unrestricted General Fund Revenues	\$5,394	\$2,573	\$2,197	\$3,657	\$4,292	\$4,808	\$4,853	\$4,628	\$4,556	\$4,548	\$4,473
Unrestricted General Fund Expenses	7,053	6,106	5,835	5,600	5,600	5,600	5,600	5,600	5,600	5,600	5,600
Budget Surplus/(Shortfall)	(\$1,659)	(\$3,533)	(\$3,638)	(\$1,943)	(\$1,308)	(\$792)	(\$747)	(\$972)	(\$1,044)	(\$1,052)	(\$1,127)
Reserve Balances											
CBRF Main Account Balance End of Year	\$6,058	\$2,622 ¹³⁸	\$2,783	\$2,236	\$1,675	\$2,935	\$2,269	\$1,365	\$365	\$0	\$0
CBRF Subaccount Balance End of Year	6,722	6,968	3,546	2,426	1,884	0	0	0	0	(613)	(1,740)
CBRF Total	\$12,780	\$9,590	\$6,329	\$4,662	\$3,558	\$2,935	\$2,269	\$1,365	\$365	(\$613)	(\$1,740)
SBRF Balance End of Year	\$3,052	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Reserves	\$15,832	\$9,590	\$6,329	\$4,662	\$3,558	\$2,935	\$2,269	\$1,365	\$365	(\$613)	(\$1,740)

Source: State of Alaska preliminary 10-year budget forecast (dated December 2014).

¹³⁸ Includes ~\$3 billion pension fund transfer.

2. Revenue Sources—Detail

a. Unrestricted Revenue

Revenue classified as unrestricted by the State is defined as “available to fund general state activities and capital projects.” In FY 2014, unrestricted revenue comprised \$5.4 billion (31%) of total State revenue. The table below details the State’s forecast for FY 2015 – FY 2024. Unrestricted revenue is expected to decline over the period as production of Alaska North Slope crude oil declines and an increased supply of oil worldwide drives prices down. Non-petroleum unrestricted revenues include taxes collected from non-petroleum related activities, excise taxes, consumption taxes, charges for services, fines, forfeitures, licenses, permits, rents, royalties and earnings on the General Fund and SBRF.¹³⁹

Additionally, the following table presents the State’s projected unrestricted general fund revenue, including its unrestricted petroleum revenue, non-petroleum revenue and investment revenue, as mentioned above.

STATE OF ALASKA 10-YEAR FORECAST OF TOTAL UNRESTRICTED GENERAL FUND REVENUE
(\$ IN MILLIONS)

	FY 2015E	FY 2016E	FY 2017E	FY 2018E	FY 2019E	FY 2020E	FY 2021E	FY 2022E	FY 2023E	FY 2024E
Unrestricted Petroleum Revenue	\$2,019	\$1,636	\$3,070	\$3,678	\$4,175	\$4,197	\$3,948	\$3,858	\$3,823	\$3,725
Unrestricted Non-petroleum Revenue	502	528	539	550	554	561	569	572	583	590
Unrestricted Investment Revenue	30	32	48	63	79	95	111	126	142	158
Total Unrestricted Revenue	\$2,552	\$2,197	\$3,657	\$4,292	\$4,808	\$4,853	\$4,628	\$4,556	\$4,548	\$4,473
<i>Percentage from Oil</i>	<i>79%</i>	<i>75%</i>	<i>84%</i>	<i>86%</i>	<i>87%</i>	<i>87%</i>	<i>85%</i>	<i>85%</i>	<i>84%</i>	<i>83%</i>

Source: Fall 2014 Revenue Sources Book.

b. Restricted Revenue

Revenue classified as restricted must be used for a specific purpose and includes funds restricted by the State constitution, federal law, trust or debt restrictions or customary practice. The largest sources of restricted revenues include restricted royalties, restricted investment income and federal revenue.

Restricted royalties track changes in price, transportation costs and production of related resources. Lower oil production could provide a drag on restricted royalties in the future. Restricted investment income relates to earnings from the Permanent Fund, CBRF and designated parts of the General Fund on their respective investments, and in FY 2014 was \$7.9 billion, or 67% of total restricted revenue. Federal revenue is exclusively restricted and includes highway, medical care, education and other purposes. The State is typically required to contribute to the same projects for which it receives federal funding—for instance, in FY 2014, the State spent \$641 million and received

¹³⁹ Fall 2014 Revenue Sources Book.

\$2.5 billion to fund federal revenue-specific projects. Historically, the State has utilized approximately 70% – 80% of its annual appropriated federal funding.¹⁴⁰

B. Balance Sheet

1. Debt

The State of Alaska currently enjoys a “triple-A” rating from all three major credit rating agencies (Standard & Poor’s¹⁴¹, Moody’s¹⁴² and Fitch¹⁴³). Rating agency reports have commended the State’s conservative financial management, citing a low debt burden and increased reserve amounts to offset any unanticipated shifts in the price or production of oil. While the State currently relies on North Slope oil production for revenues, there are long-term alternatives being considered in natural gas (e.g., the Project, ASAP) and mineral production-related revenue, potential implementation of a State-wide broad-based tax, and the potential use of earnings of the Permanent Fund to offset costs of government services. The State’s current debt position is very conservative¹⁴⁴ and, as a result, the State has maintained a level of flexibility in funding its capital projects that is not experienced by many other states.¹⁴⁵

The conservative nature of the State’s debt practices is evidenced by its relatively low level of debt service as a percentage of unrestricted general fund revenue. While the current State policy is designed to limit this ratio to 8.0%, for the last ten years the State has remained below 5.0% and achieved 3.3% for fiscal year 2013.¹⁴⁶

In addition to the low level of debt service as a percentage of unrestricted general fund revenue, another metric demonstrating the conservative debt position of the State is the trajectory of its general obligation debt retirement. Approximately 70% of the current general obligation debt outstanding is expected to amortize over the next 10 years, allowing for increased financial flexibility.¹⁴⁷

The State has traditionally utilized long-term fixed rate debt in relation to its general obligation bond issuances. This, in turn, has resulted in limited exposure to floating or variable rate debt, swaps or other derivative products used to hedge interest rate risk. While it is recognized that agencies of the State use variable rate debt and derivative products, limited direct exposure exists for the State itself, and the risks associated with such products are generally not found in the State’s general obligation bond indebtedness.

¹⁴⁰ Fall 2014 Revenue Sources Book.

¹⁴¹ “Alaska Appropriations; General Obligation; Moral Obligation,” Standard & Poor’s, January 7, 2013.

¹⁴² “Moody’s revises Alaska’s outlook to negative after oil price plunge; affirms Aaa GO rating,” Moody’s, December 19, 2014.

¹⁴³ “State of Alaska General Obligation Bonds Full Rating Report,” Fitch Ratings, April 16, 2013.

¹⁴⁴ FirstSouthwest analysis.

¹⁴⁵ The State’s conservative position has been enhanced by its decision to employ a “pay-as-you-go” strategy as a primary source of capital.

¹⁴⁶ FirstSouthwest analysis.

¹⁴⁷ FirstSouthwest analysis.

The State’s ability to fund capital projects with current revenues has played a significant role in the relatively low level of general obligation debt for the State. The reliance on current revenues has limited the State’s need for bond issuance as a funding source and, as a result, has allowed the State to maintain a flexible debt profile.

a. State Bonding Capacity Considerations

In light of the State’s relatively conservative debt practices discussed above, the State may potentially have capacity to issue additional debt. A primary consideration that must be evaluated in calculating the amount of any additional capacity is the impact of incremental debt on the State’s credit rating. Additionally, the State must decide whether it is willing to accept potential downgrades of its credit rating to gain the benefit of additional debt capacity.

The State of Alaska’s debt service as a percentage of total budget/revenues is the second-lowest among all states, at 1.2% in 2013.¹⁴⁸ This ratio ranges from 0.9% (Iowa) to 8.2% (Delaware) for “triple-A” rated States, which makes it difficult to judge at exactly what level the State could expect to receive a downgrade; only four states have ratios above 10%: Connecticut (Aa3), Massachusetts (Aa1), Illinois (A3) and New York (Aa2). However, for other debt ratios (e.g., debt as a percentage of GDP, personal income, etc.), the State is much closer to or above the medians for all states.

Lazard has requested that FirstSouthwest perform an analysis that takes the above factors into consideration in order to calculate the State’s potential additional borrowing capacity. The methodology and results of this analysis are presented below.

STATE BONDING CAPACITY ANALYSIS¹⁴⁹

	METHODOLOGY— GENERAL	METHODOLOGY— SCENARIO SPECIFIC	ILLUSTRATIVE RESULTS
SCENARIO 1—STATE MAINTAINS CURRENT “Aaa” RATING	<ul style="list-style-type: none"> All future debt issuances are structured as tax-exempt bonds amortized over 20 years, with level debt service payments 	<ul style="list-style-type: none"> Debt service in any year cannot exceed the targeted level of 5% of the prior year’s unrestricted general fund revenues 	<ul style="list-style-type: none"> State has capacity to issue up to \$2.7 billion of incremental debt over the next 10 years
SCENARIO 2—STATE IS DOWNGRADED TO “Aa1” RATING	<ul style="list-style-type: none"> Assumed tax-exempt interest rates based on the target rating (3.53% for Aaa, 3.62% for Aa1, 3.70% for Aa2)¹⁵⁰ Annual unrestricted general fund revenues available to pay debt service through 2024 are set at amounts stipulated in the Fall 2014 Revenue Sources Book¹⁵¹ 	<ul style="list-style-type: none"> Debt service in any year cannot exceed the targeted level of 8% of the prior year’s unrestricted general fund revenues 	<ul style="list-style-type: none"> State has capacity to issue up to \$4.7 billion of incremental debt over the next 10 years
SCENARIO 3—STATE IS DOWNGRADED TO “Aa2” RATING		<ul style="list-style-type: none"> Debt service in any year cannot exceed the targeted level of 10% of the prior year’s unrestricted general fund revenues 	<ul style="list-style-type: none"> State has capacity to issue up to \$5.9 billion of incremental debt over the next 10 years

¹⁴⁸ Debt service as a percentage of total budget/revenues is a ratio used by rating agencies, which is different from debt service as a percentage of unrestricted general fund revenue, a ratio mandated by State policy to remain below 8%.

¹⁴⁹ FirstSouthwest analysis.

¹⁵⁰ I.e., the State’s cost of debt would potentially increase with ratings downgrades.

¹⁵¹ If forecasted Project revenues are included in this projection, the State would see its debt capacity increase to \$3.8 billion, \$6.4 billion and \$8.1 billion in Scenario 1, Scenario 2 and Scenario 3, respectively.

As can be seen above, FirstSouthwest’s analysis indicates that State has a moderate amount of capacity to issue incremental debt (in this instance, “debt” means general obligation debt and State-supported debt) in the scenario where it maintains its current rating (\$2.7 billion) and stays below the 5% target level of debt service as a percentage of unrestricted general fund revenues. However, if the State is willing to take a downgrade to “Aa1”, it can still stay under its policy-driven 8% cap on debt service as a percentage of unrestricted general fund revenues and gains an additional \$2.0 billion of debt capacity (i.e., the total incremental debt capacity rises to \$4.7 billion). Finally, if the State is willing to accept a downgrade to “Aa2”, it would see its capacity to issue incremental debt rise to \$5.9 billion.¹⁵²

2. Overview of State Funds

The State is responsible for overseeing a variety of different funds that hold the majority of the State’s assets. A brief overview of these funds is presented below.

OVERVIEW OF STATE FUNDS

		DESCRIPTION	ASSET ALLOCATION	INVESTMENT MANDATE
OTHER FUNDS	PERMANENT FUND	<ul style="list-style-type: none"> Established in 1976; invests a portion¹⁵³ of the State’s mineral lease rentals, royalties, royalty share proceeds and federal mining revenue-sharing payments and bonuses in income-producing investments Initially intended to steer the State towards better management of the influx of private lease revenue from drilling and exploration activities Since 1982, has paid an annual dividend to Alaska residents (the “Permanent Fund Dividend”); was \$1,884 in 2014 	<ul style="list-style-type: none"> Fund size: \$52.4 billion U.S. Bonds: 21% International Equity: 18% Alternatives: 18% Other: 43% 	<ul style="list-style-type: none"> Target real return of 5.2% Divided into two subcategories: principal and earnings reserve Principal may not be spent, while the earnings reserve, which consists of realized gains from investments as well as unrealized gains, can be spent for any public purpose
	GeFONSI	<ul style="list-style-type: none"> “General Fund and Other Non-segregated Investments” represents a pool of funds managed by the State’s Treasury Division 	<ul style="list-style-type: none"> Fund size: \$4.5 billion Liquidity/short-term: 72% Intermediate-term: 28% 	<ul style="list-style-type: none"> Target return of 2.1% Pooling method reduces liquidity needs and allows for a more aggressive investment mandate
	SBRF	<ul style="list-style-type: none"> General savings fund consisting of appropriations in excess of funds received by the State 	<ul style="list-style-type: none"> Fund size: \$3.7 billion Short-term: 47% Intermediate-term: 33% Broad Market/FI: 20% 	<ul style="list-style-type: none"> Invested in such a way as to “meet immediate expenditure needs” of the State
	CBRF	<ul style="list-style-type: none"> Established in 1990 and funded through resolution of disputes about the amount of certain mineral-related income Consists of a main fund and subaccount 	<ul style="list-style-type: none"> Fund size: \$10.9 billion Main Account: <ul style="list-style-type: none"> Short-term: 47% Intermediate-term: 33% Broad Market/FI: 20% Subaccount: <ul style="list-style-type: none"> Domestic Equity: 40% Broad Market/FI: 39% International Equity: 21% 	<ul style="list-style-type: none"> Main Account: <ul style="list-style-type: none"> Expected to return “competitive market rate” Subaccount: <ul style="list-style-type: none"> May invest in higher risk/return asset classes than the Main Account, under the assumption that the funds used would not otherwise be needed for at least five years
	PCE ENDOWMENT FUND	<ul style="list-style-type: none"> The Power Cost Equalization Endowment Fund (“PCE Endowment Fund”) was created to provide for affordable electric utility costs for rural Alaska Established in 2001 with funds from the CBRF and proceeds from the sale of a hydroelectric project 	<ul style="list-style-type: none"> Fund size: \$974 million Domestic Equity: 44% Broad Market/FI: 33% International Equity: 23% 	<ul style="list-style-type: none"> Target return of 7.0%
OTHER	<ul style="list-style-type: none"> Various other funds managed by the State, including the Public School Trust Funds and Retiree Health Insurance Fund 	<ul style="list-style-type: none"> Fund size: \$1.4 billion Various asset allocations 	<ul style="list-style-type: none"> Various 	

Sources: Alaska Constitution, and websites including State Department of Revenue, Alaska Permanent Fund Corporation and Alaska Energy Authority.

Note: FI refers to fixed income. Fixed income securities (e.g., bonds) require the security issuer to make scheduled payments to investors. This is in contrast to equity securities, which generally have no such requirement, albeit equity issuers frequently pay discretionary dividends.

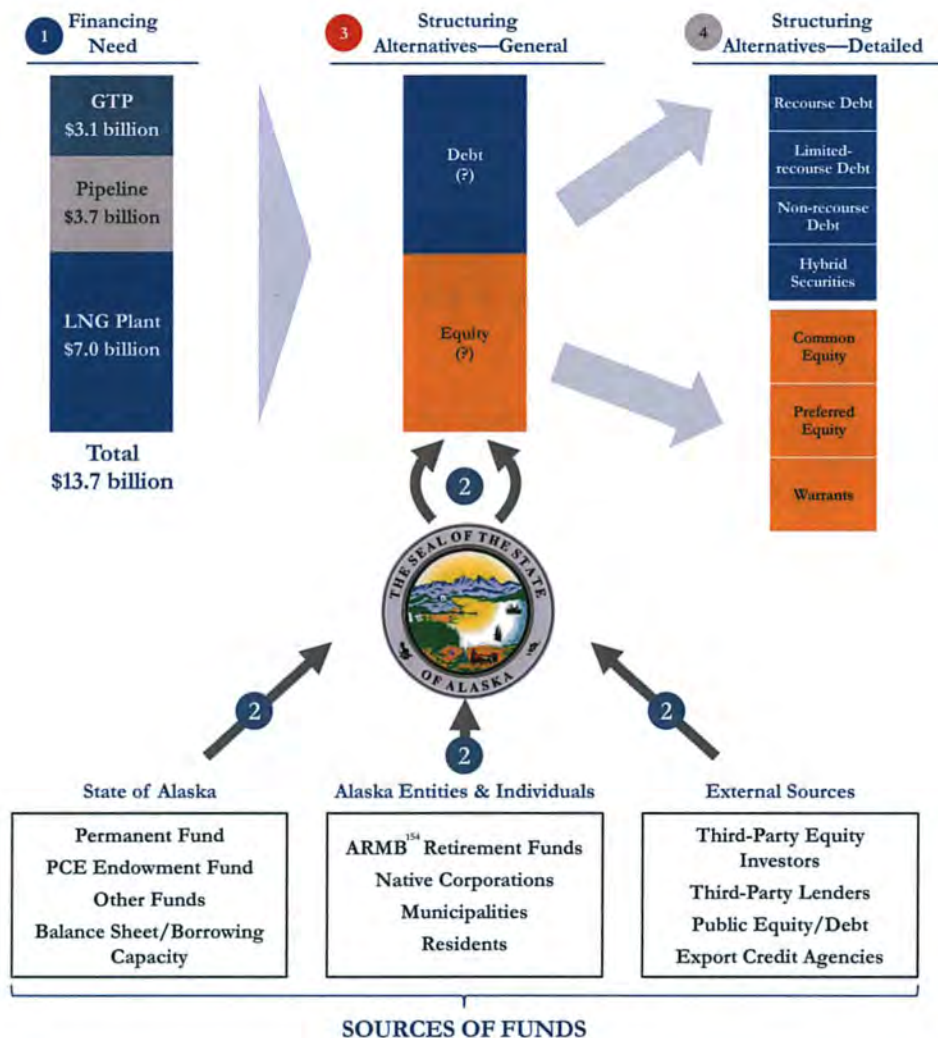
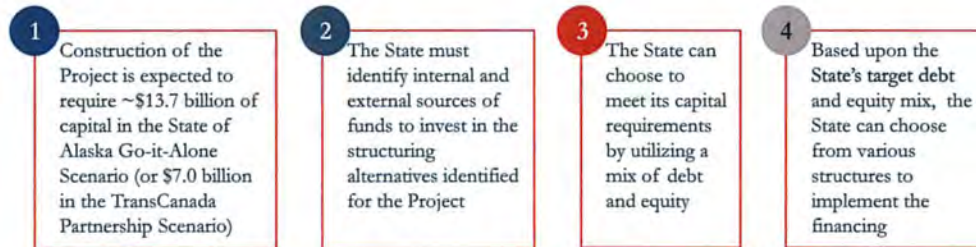
¹⁵² If forecasted Project revenues are included in this projection, the State would see its debt capacity increase to \$3.8 billion, \$6.4 billion and \$8.1 billion in Scenario 1, Scenario 2 and Scenario 3, respectively.

¹⁵³ Specified as 25% for mineral leases issued before circa 1980 and 50% for mineral leases issued after circa 1980.

VI Summary Preliminary Financing Considerations

VI. Summary Preliminary Financing Considerations

The State of Alaska’s financing strategy with respect to the AKLNG Project will likely be largely determined by the State’s overall Project funding requirement, its available sources of funds and the “optimal” capital structure (e.g., debt/equity mix). These determinations are interrelated and should be evaluated together, as illustrated below.



¹⁵⁴ ARMB denotes Alaska Retirement Management Board.

A. Description of Financing Need

As described earlier, the State must finance its portion of the upfront investment in the Project in order to participate as a 25% owner in the Project and receive future Project cash flows. Based on current forecasts, this financing amount could range from approximately \$7.0 billion (if it pursues the TransCanada Partnership Scenario) to \$13.7 billion (if it pursues the State Go-it-Alone Scenario).^{155, 156} These figures are presented below.

STATE OF ALASKA PROJECT INVESTMENT—TRANSCANADA PARTNERSHIP SCENARIO (\$ IN MILLIONS)

	PRE-FEED		FEED			EPC					Total
	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	
GTP	\$-	\$-	\$-	\$-	\$-	\$-	\$-	\$-	\$-	\$-	\$-
Pipeline	-	-	-	-	-	-	-	-	-	-	-
LNG Plant	14	29	61	72	46	954	1,637	1,686	1,390	1,073	6,964
Total	\$14	\$29	\$61	\$72	\$46	\$954	\$1,637	\$1,686	\$1,390	\$1,073	
Phase Total	\$43		\$180			\$6,741					\$6,964¹⁵⁷

STATE OF ALASKA PROJECT INVESTMENT—STATE GO-IT-ALONE SCENARIO (\$ IN MILLIONS)

	PRE-FEED		FEED			EPC					Total
	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	
GTP	\$11	\$22	\$46	\$54	\$35	\$415	\$712	\$733	\$604	\$467	\$3,099
Pipeline	11	22	46	54	35	498	854	880	725	560	3,685
LNG Plant	14	29	61	72	46	954	1,637	1,686	1,390	1,073	6,962
Total	\$35	\$73	\$153	\$180	\$116	\$1,866	\$3,203	\$3,300	\$2,719	\$2,100	
Phase Total	\$108		\$450			\$13,188					\$13,745¹⁵⁸

Source: Black & Veatch Model, dated February 2014.

The State must consider its total Project investment and the investment required at different phases of development. Given the varying degrees of risk associated with different phases of development and that the majority of the financing need (>95%) comes during the EPC phase, the State may choose to use different sources of financing and financing structures for each of the phases of the Project.

¹⁵⁵ Black & Veatch Model, dated February 2014.

¹⁵⁶ As discussed above in Section IV.F, under the TransCanada Partnership Scenario, the State is responsible for repaying TransCanada's upfront investment via a return of capital mechanism in the tariff structure.

¹⁵⁷ Represents 8% of State's total assets as of FY 2013.

¹⁵⁸ Represents 16% of State's total assets as of FY 2013.

B. Sources of Funds

The State has a variety of sources potentially available to fund its portion of the upfront investment in the Project. These sources include those that the State has direct access to, those that could come from Alaska entities and individuals, and those that could come from external sources. A brief overview of the various funding sources is presented below.

		DESCRIPTION
STATE OF ALASKA	PERMANENT FUND	<ul style="list-style-type: none"> The State is responsible for managing \$52.4 billion in the Permanent Fund <ul style="list-style-type: none"> Currently broadly invested across public/private debt and equity securities, with 19% currently allocated to real assets¹⁵⁹ Potential to allocate substantial capital to the Project, although no precedent exists for direct asset-level investments (generally conducted indirectly via private equity fund managers) Potential for the Legislature to allocate Permanent Fund earnings for investment in the Project
	PCE ENDOWMENT FUND	<ul style="list-style-type: none"> The PCE Endowment Fund consists of approximately \$1.0 billion invested in domestic and international equities, and fixed income securities <ul style="list-style-type: none"> The PCE Endowment Fund could potentially invest directly in the Project
	OTHER FUNDS	<ul style="list-style-type: none"> Through GeFONSI, CBRF, SBRF and various other funds, the State manages over \$19.0 billion <ul style="list-style-type: none"> While the State generally invests these funds in short- to medium-term liquid securities such that they may be drawn upon to pay expenses and fund budget shortfalls, certain funds could potentially invest in longer-term, less liquid assets
	BALANCE SHEET / BORROWING CAPACITY	<ul style="list-style-type: none"> The State currently has \$3.0 billion of long-term debt outstanding <ul style="list-style-type: none"> Revenue bonds, general obligation debt, capital leases, etc. compose this balance The State has the capacity to issue incremental debt of \$3.8 – \$8.1 billion, depending on the State’s willingness to accept a rating downgrade¹⁶⁰
ALASKA ENTITIES AND INDIVIDUALS	ARMB RETIREMENT FUNDS	<ul style="list-style-type: none"> ARMB is responsible for managing \$26.6 billion of funds across seven systems <ul style="list-style-type: none"> Currently broadly invested across public/private debt and equity securities Potential to allocate capital to the Project given current fund allocation to real assets¹⁶¹
	NATIVE CORPORATIONS	<ul style="list-style-type: none"> Alaska’s 13 native corporations generated \$368 million of net income in 2010¹⁶² <ul style="list-style-type: none"> These native corporations could potentially invest capital in the Project as a means of generating additional income and returning increased dividends to members
	MUNICIPALITIES	<ul style="list-style-type: none"> Alaska municipalities generate revenues via property, sales and severance taxes, and other fees <ul style="list-style-type: none"> While these revenues are generally used to fund operating budgets, municipalities could potentially invest directly in the Project Alaska municipalities currently have \$3.2 billion of debt outstanding¹⁶³ and generally exhibit strong credit ratings¹⁶⁴ <ul style="list-style-type: none"> Additional debt could be issued by municipalities to fund an investment in the Project
	RESIDENTS	<ul style="list-style-type: none"> Residents of Alaska are also potential investors in the Project <ul style="list-style-type: none"> Alaska residents could potentially elect to designate an amount of their annual Permanent Fund dividend to the Project (dividend was \$1,884 per resident in 2014) Alaska residents could potentially invest personal funds (e.g., savings) directly
EXTERNAL SOURCES	THIRD-PARTY EQUITY INVESTORS	<ul style="list-style-type: none"> Third-party institutional investors, including infrastructure direct investors (e.g., pension funds, sovereign wealth funds, insurance companies, banks, private equity sponsors, etc.), seek investments with long-term cash flow characteristics
	THIRD-PARTY LENDERS	<ul style="list-style-type: none"> Third-party lenders, including financing banks (e.g., JP Morgan, Bank of America, etc.), could potentially lend to the Project
	PUBLIC EQUITY/DEBT	<ul style="list-style-type: none"> Retail and institutional investors, via brokers and otherwise, make investments in a variety of public debt and equity securities
	EXPORT CREDIT AGENCIES	<ul style="list-style-type: none"> Export credit agencies provide loans to aid in the development of projects that provide their sponsor countries with key imports or exports, such as LNG or other natural resources <ul style="list-style-type: none"> Examples include Japan Bank for International Cooperation (“JBIC”) (\$126 billion of outstanding loans and guarantees), Korea Ex-Im Bank (\$86 billion of outstanding loans and guarantees), Export-Import Bank of the United States (\$79 billion of outstanding loans and guarantees)

¹⁵⁹ “Asset Allocation,” Alaska Permanent Fund Corporation.

¹⁶⁰ Per FirstSouthwest analysis in case where Project revenues are considered.

¹⁶¹ ~\$3.6 billion currently invested in real assets. However, the amount available to invest in the Project is likely much less, due, in part, to current illiquid investments and investment concentration concerns (i.e., the ARMB would not likely concentrate a substantial portion of its funds on one investment).

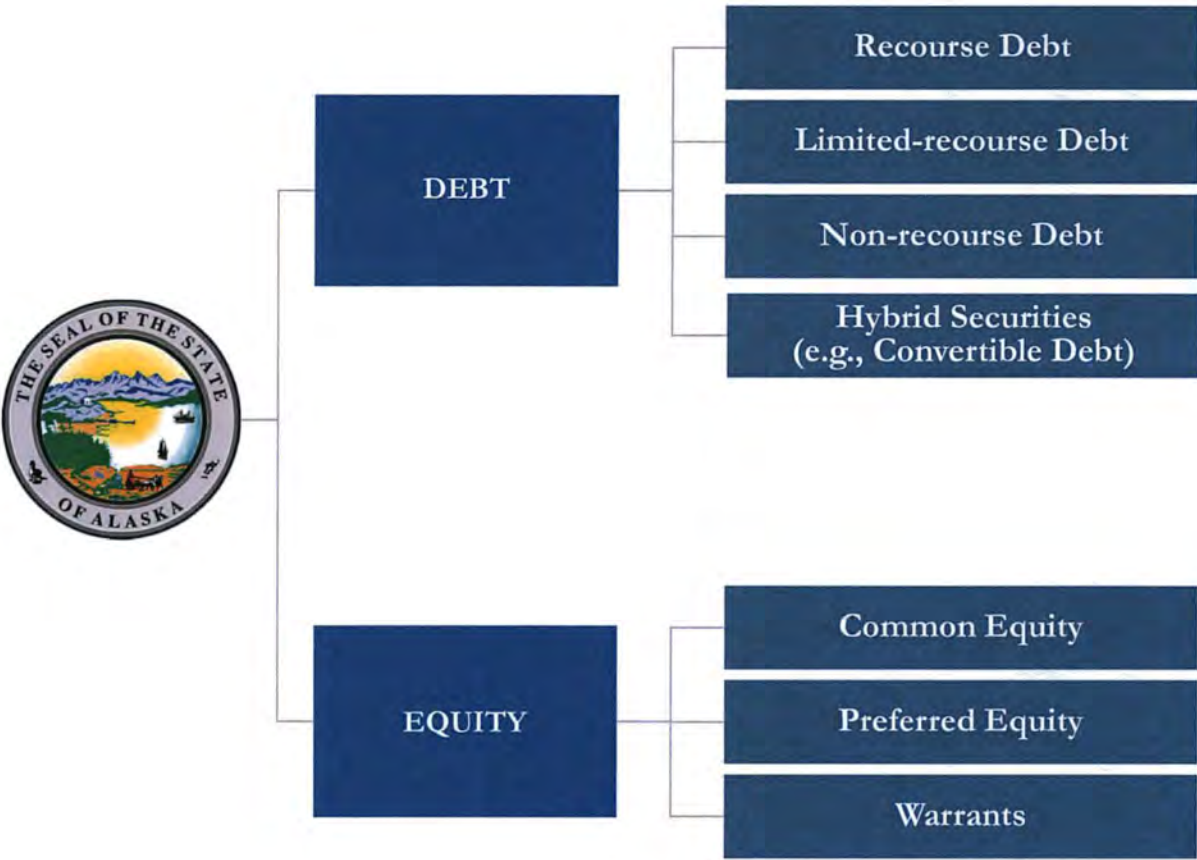
¹⁶² “Regional Alaska Native Corporations,” GAO, December 2012.

¹⁶³ “Alaska Public Debt,” The State of Alaska, January 2014.

¹⁶⁴ Moody’s.

C. Debt and Equity Structuring Alternatives

Irrespective of the funding source used, the State will need to evaluate the optimal financing structure via which those funds are invested in the Project.¹⁶⁵ In general, the State could structure these funds as either debt or equity interests in the Project. More specifically, a spectrum of structuring alternatives exists for both debt and equity. Each alternative offers different risk and return profiles, as well as other characteristics related to seniority/priority, payout structure, governance rights and other features.¹⁶⁶



¹⁶⁵ The State may also need to consider the overall capital structure of the Project (i.e., how other Project owners have chosen to capitalize their investments in the Project).

¹⁶⁶ Structuring alternatives to be discussed in greater detail in Section VII.

D. Other Considerations

The State might consider other alternatives to lower its cost of capital, shift/mitigate risk, or otherwise achieve its financing objectives. These alternatives could include:

	DESCRIPTION
CREDIT SUPPORT	<ul style="list-style-type: none"> ■ The State could provide or access credit support to spread risks posed by the Project to other parties and to lower the Project’s cost of capital ■ Potential opportunities for credit support include the following: <ul style="list-style-type: none"> ■ State provides a guarantee on debt payments owed by an external Project sponsor ■ State seeks a guarantee on debt payments owed by the State; such credit support may be provided by, for example, the U.S. Federal Government, multilateral banks, etc. ■ State or other third parties provide guarantees in the form of a backstop to Project cost overruns ■ Guarantees by financially strong third parties could potentially lower the overall cost of debt associated with financing; however, a guarantee issued by the State could potentially impact the State’s balance sheet and credit rating, even if the State is only indirectly obligated on the liability or the risk of triggering funding support is remote
INSURANCE/ RISK MITIGATION	<ul style="list-style-type: none"> ■ The State could purchase insurance to provide downside protection for various aspects of the Project to shift certain risks to third parties ■ Potentially insurable areas include: <ul style="list-style-type: none"> ■ Construction Risks: Covers losses or damage to materials, supplies, equipment or temporary structures for general building and engineering purposes, respectively ■ Delay in Start Up Risk: Covers any delays in the Project’s ability to generate revenue in a timely manner ■ <i>Force Majeure</i>: Covers any risks associated with acts of nature (e.g., storms, earthquakes, etc.) ■ Performance Failure or Design Risk: Covers any losses arising from ineffective design or workmanship ■ Political Risk: The State could provide contractual assurances that any increases in costs or delays associated with future Alaska political decisions would be borne by the State ■ The greater the likelihood of a claim and the larger the size of that claim dictate the cost of an associated premium paid to an insurer (i.e., insurance against large and likely events would likely be more expensive than insurance against small and unlikely events)
EQUITY/DEBT SYNDICATION	<ul style="list-style-type: none"> ■ The State could syndicate (i.e., market to third parties) its interest in the Project to spread risks posed by the Project to other parties and to provide liquidity to the State at later stages of Project development ■ Potential opportunities for syndications might include: <ul style="list-style-type: none"> ■ Debt and/or equity syndication to Alaska individuals, Alaska corporations, or individuals and corporations from outside the State ■ Syndication provides an opportunity to rotate capital out of the Project once specific Project milestones are achieved and the overall Project risk is reduced

VII Overview of Potential Structuring Alternatives

VII. Overview of Potential Structuring Alternatives

The State's interest in the Project would—as a practical, operational/governance and legal matter—likely be facilitated through a separate, standalone entity (herein referred to as the “State Project Company”).¹⁶⁷ The State Project Company would be similar to many other companies in that it would be able to issue debt and equity in order to raise funds to pursue investments. The State Project Company, however, would likely be limited to investing only in the AKLNG Project, and would subsequently serve to receive Project revenues, make debt service payments and generally manage the State's investment interest in the Project. Upon formation of the State Project Company, the State would be the sole owner and parent of the entity.

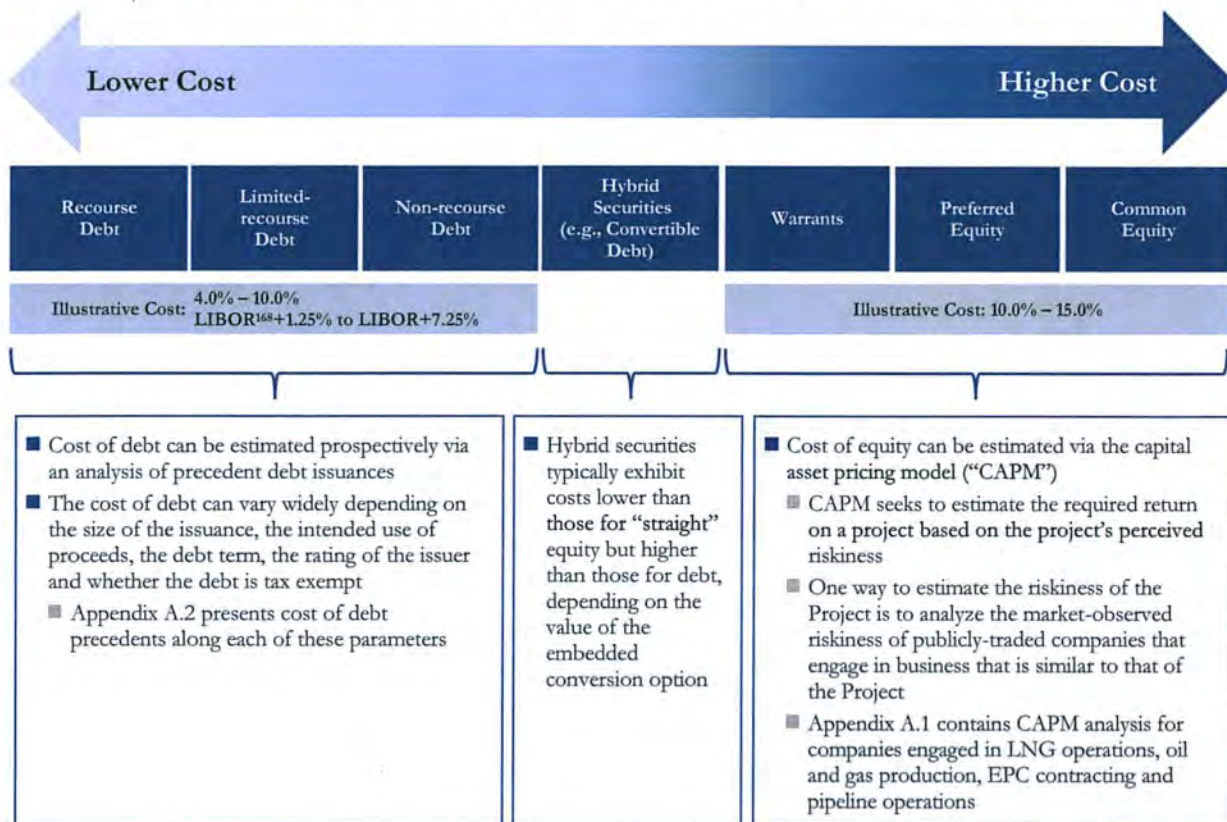
Importantly, the State Project Company would have various funding sources by which it would be capitalized, and various structuring alternatives, or ways in which it could invest in the Project. For example, the Permanent Fund (a funding source) might wish to invest in the State Project Company as a common equity holder (a structuring alternative). Similarly, the State could issue general obligation debt (a funding source) and, with the proceeds, decide to invest in the State Project Company as a non-recourse debt holder (a structuring alternative). The State may choose to fund the State Project Company via multiple funding sources—including Alaska municipalities, individuals and other State entities—and the State Project Company might invest in the Project via multiple structures, none of which are mutually exclusive.

While reading the following sections, which describe in detail the various ways that the State Project Company could potentially finance itself in order to invest in the Project, it is important to consider the relative cost of each of the structuring alternatives presented. The State Project Company's financing cost would likely be a function of many factors, including its capital structure and the Project's position in the development lifecycle. Various debt and equity alternatives have different relative costs, based on specific attributes. For example, non-recourse debt is typically more expensive than recourse debt, because the risk to lenders is higher in a default scenario. Similarly, preferred equity is typically less expensive than common equity, because preferred equity shareholders receive dividends before common equity shareholders receive dividends.

Ultimately, the State Project Company should seek to optimize its capital structure with debt, equity or a combination thereof, based on its priorities, including control and governance rights, operational flexibility and, importantly, cost. The State Project Company's blended financing cost (i.e., its weighted average cost of capital (“WACC”)) would be determined based on the relative amounts of debt and equity in its capital structure, and their respective costs. The following illustrates the relative cost of the various debt and equity structuring alternatives, each of which will be further explained in the following sections.

¹⁶⁷ An existing State entity could potentially serve as the State Project Company, depending on various legal and structuring considerations to be determined in the future.

ILLUSTRATIVE FINANCING COST—CAPITAL STRUCTURE



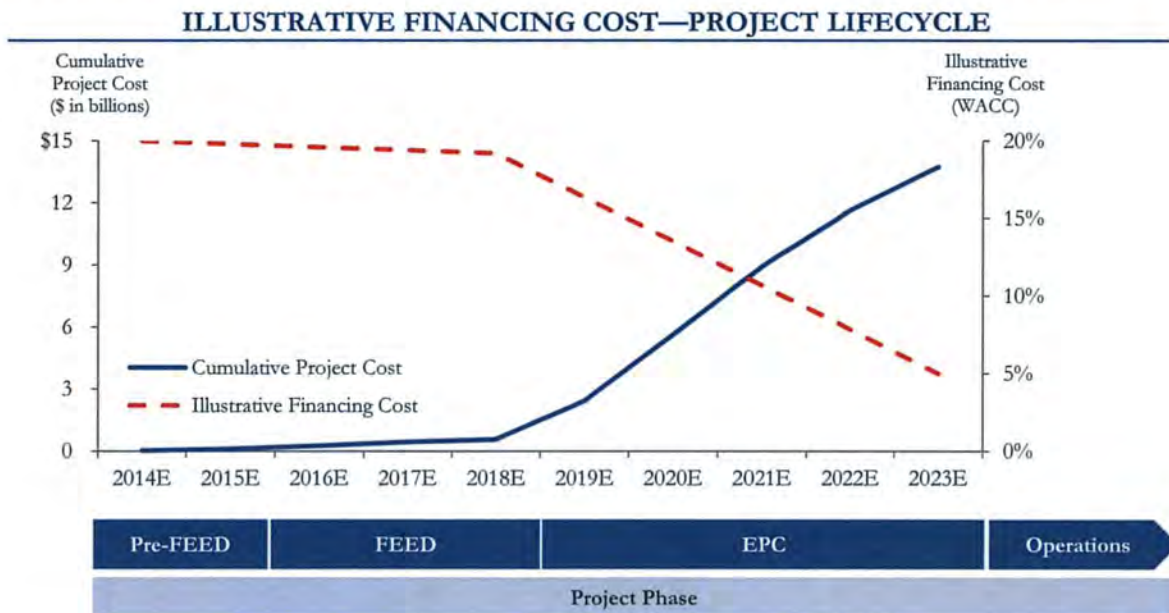
Another determinant of the State Project Company’s cost of financing is the perceived riskiness of its projected cash flows. The risk related to the Project’s expected cash flows will vary over time. In the early stages of the Project’s development lifecycle, financing costs are likely to be highest, due to the perceived risks associated with realization of the Project and, therefore, future Project cash flows. As the Project advances in its development lifecycle, the certainty of future Project cash flows should increase and the perceived risk associated with the Project should decrease accordingly, leading to lower financing costs.

As a practical matter, lenders would likely be reluctant to finance the Project in its early stages (absent some direct credit support/guarantee from the State or others), requiring the State Project Company to structure its initial investment as a form of equity. As the Project advances, permitting is completed, commercial arrangements are secured and construction is ready to commence, lenders would likely be more able to provide debt financing and the cost of securing third party financing should also be more competitive.

¹⁶⁸ The London Interbank Offered Rate (“LIBOR” or “L”) is a benchmark rate that banks charge each other for short-term loans. LIBOR is often used in determining the interest rate for floating-rate debt issuances. As of December 31, 2014, the 3-month LIBOR rate was 0.26%.

Similarly, as the Project advances, the value of the State’s ownership interest would likely increase. As the Project reaches commercial operation and is fully “de-risked”, the State may choose to monetize a portion of its ownership interest (via issuing debt, selling equity¹⁶⁹ or otherwise) in order to diversify its investment, pursue other relevant investment opportunities or allocate capital to other State priorities.

The following chart illustrates the relationship between the cost of financing and Project phase.



Note: Cumulative Project cost shown for State Go-it-Alone scenario.

¹⁶⁹ The State could also monetize its ownership interest in the Project via alternative structures, which include master limited partnerships and YieldCos, among others.

A. Debt

1. Recourse Debt

DESCRIPTION	<ul style="list-style-type: none"> ■ The State Project Company could issue recourse debt that may be secured by the revenue/assets of the State Project Company, but that ultimately has full recourse to the State <ul style="list-style-type: none"> ■ Recourse debt is a type of a loan that has full recourse to the borrower's parent entity ■ The lender would be entitled to principal and interest payments based on a negotiated amortization schedule and interest rate, respectively <ul style="list-style-type: none"> ■ Failure to make payments on time could result in a default scenario ■ In a default scenario, the State (as the parent of the State Project Company) would be fully liable for principal repayment <ul style="list-style-type: none"> ■ The lender's recourse to the State would not be limited ■ Recourse debt could potentially be accompanied by restrictive covenants, which would limit the actions of the State Project Company <ul style="list-style-type: none"> ■ Categories of covenants include maintenance covenants and incurrence covenants; violation of covenants may result in a default scenario <ul style="list-style-type: none"> – A maintenance covenant might require the State Project Company to maintain or achieve a certain level of financial performance to avoid default (e.g., a covenant requiring the State Project Company to maintain a certain ratio of Project cash flow to scheduled debt service) – Incurrence covenants might prohibit the State Project Company from undertaking certain actions (e.g., incurring additional debt or making a restricted payment) ■ A lender's claim on the State Project Company would expire after repayment of the initial loan principal <ul style="list-style-type: none"> ■ A lender's recourse to the State would expire after the initial loan principal was repaid
BENEFITS	<ul style="list-style-type: none"> ■ Less expensive than equity alternatives; additionally, least expensive form of debt alternatives ■ No dilution of the State's ownership or control interest in the State Project Company <ul style="list-style-type: none"> ■ Lenders have a defined interest in the State Project Company, limited to principal and interest payments ■ Debt service requirements are generally very predictable and stable over time and may therefore be structured in accordance with the State Project Company's investing needs and expected future revenues
CONSIDERATIONS	<ul style="list-style-type: none"> ■ State Project Company creditors have full recourse to the State in the event of a default scenario <ul style="list-style-type: none"> ■ Potentially significant impact on the State's credit rating ■ Restrictive covenants reduce operational flexibility for the State Project Company ■ Recourse debt can create conflicts of interest among State Project Company stakeholders <ul style="list-style-type: none"> ■ Lenders typically favor more conservative management choices, while equity investors favor riskier management choices with the potential for a higher payout ■ Potential for financial distress (not limited to Project level)
SUMMARY ASSESSMENT	<ul style="list-style-type: none"> ■ Riskiest debt alternative for the State Project Company; full recourse to the State and potentially significant impact on the State's credit rating ■ Relatively less expensive than other debt alternatives ■ Allows the State to maintain its undiluted ownership and control interest in the State Project Company

2. Limited-recourse Debt

<p>DESCRIPTION</p>	<ul style="list-style-type: none"> ■ The State Project Company could issue limited-recourse debt that may be secured by the revenue/assets of the State Project Company, but that ultimately has some amount of recourse to the State <ul style="list-style-type: none"> ■ Limited-recourse debt is a type of a loan that has recourse to the borrower's parent entity, but only to a specified amount and generally only for a specified period of time ■ The lender would be entitled to principal and interest payments based on a negotiated amortization schedule and interest rate, respectively <ul style="list-style-type: none"> ■ Failure to make payments on time could result in a default scenario ■ In a default scenario, the State (as the parent of the State Project Company) would be liable (only up to a certain amount) for principal repayment <ul style="list-style-type: none"> ■ The lender's recourse to the State would generally be limited to a negotiated amount (e.g., 50% of the original loan amount) and time period (e.g., until the Project has reached operations) ■ Limited-recourse debt could potentially be accompanied by restrictive covenants, which would limit the actions of the State Project Company <ul style="list-style-type: none"> ■ Categories of covenants include maintenance covenants and incurrence covenants; violation of covenants may result in a default scenario <ul style="list-style-type: none"> – A maintenance covenant might require the State Project Company to maintain or achieve a certain level of financial performance to avoid default (e.g., a covenant requiring the State Project Company to maintain a certain ratio of Project cash flow to scheduled debt service) – Incurrence covenants might prohibit the State Project Company from undertaking certain actions (e.g., incurring additional debt or making a restricted payment) ■ A lender's claim on the State Project Company would expire after repayment of the initial loan principal <ul style="list-style-type: none"> ■ A lender's recourse to the State would also expire at this time, unless negotiated to be earlier per the above (e.g., when the Project has reached operations)
<p>BENEFITS</p>	<ul style="list-style-type: none"> ■ Less expensive than equity alternatives ■ Limited recourse to the State in the event of a State Project Company default <ul style="list-style-type: none"> ■ Potential for only moderate impact on the State's credit rating ■ No dilution of the State's ownership or control interest in the State Project Company <ul style="list-style-type: none"> ■ Lenders have a defined interest in the State Project Company, limited to principal and interest payments ■ Debt service requirements are generally very predictable and stable over time and may therefore be structured in accordance with the State Project Company's investing needs and expected future revenues
<p>CONSIDERATIONS</p>	<ul style="list-style-type: none"> ■ More expensive than recourse debt, albeit less expensive than non-recourse debt ■ Restrictive covenants reduce operational flexibility for the State Project Company ■ Limited-recourse debt can create conflicts of interest among State Project Company stakeholders <ul style="list-style-type: none"> ■ Lenders typically favor more conservative management choices, while equity investors favor riskier management choices with the potential for a higher payout ■ Potential for financial distress (not limited to Project level)
<p>SUMMARY ASSESSMENT</p>	<ul style="list-style-type: none"> ■ Somewhat risky debt alternative for State Project Company; only limited recourse to the State and potential for only moderate impact on the State's credit rating ■ "Middle of the road" in terms of cost vs. other debt alternatives; still less expensive than equity alternatives ■ Allows the State to maintain its undiluted ownership and control interest in the State Project Company

3. Non-recourse Debt

DESCRIPTION	<ul style="list-style-type: none"> ■ The State Project Company could issue non-recourse debt¹⁷⁰ secured by the revenue/assets of the State Project Company <ul style="list-style-type: none"> ■ Non-recourse debt is a type of a loan that is secured by specific assets or cash flows (i.e., collateral) ■ The lender would be entitled to principal and interest payments based on a negotiated amortization schedule and interest rate, respectively <ul style="list-style-type: none"> ■ Failure to make payments on time could result in a default scenario ■ In a default scenario, the State (as the parent of the State Project Company) would not be liable for principal repayment <ul style="list-style-type: none"> ■ The lender's only recourse would be the revenue/assets used as collateral for the loan ■ Non-recourse debt could potentially be accompanied by restrictive covenants, which would limit the actions of the State Project Company <ul style="list-style-type: none"> ■ Categories of covenants include maintenance covenants and incurrence covenants; violation of covenants may result in a default scenario <ul style="list-style-type: none"> – A maintenance covenant might require the State Project Company to maintain or achieve a certain level of financial performance to avoid default (e.g., a covenant requiring the State Project Company to maintain a certain ratio of Project cash flow to scheduled debt service) – Incurrence covenants might prohibit the State Project Company from undertaking certain actions (e.g., incurring additional debt or making a restricted payment) ■ A lender's claim on the State Project Company would expire after repayment of the initial loan principal
BENEFITS	<ul style="list-style-type: none"> ■ Less expensive than equity alternatives ■ No recourse to the State in the event of a State Project Company default <ul style="list-style-type: none"> ■ Minimal (if any) impact on State's credit rating ■ No dilution of the State's ownership or control interest in or control of the State Project Company <ul style="list-style-type: none"> ■ Lenders have a defined interest in the State Project Company, limited to principal and interest payments ■ Debt service requirements are generally very predictable and stable over time and may therefore be structured in accordance with the State Project Company's investing needs and expected future revenues
CONSIDERATIONS	<ul style="list-style-type: none"> ■ More expensive than other debt alternatives ■ Restrictive covenants reduce operational flexibility for the State Project Company; these covenants are typically more restrictive when attached to non-recourse debt than other debt or equity alternatives ■ Non-recourse debt can create conflicts of interest among State Project Company stakeholders <ul style="list-style-type: none"> ■ Lenders typically favor more conservative management choices, while equity investors favor riskier management choices with the potential for a higher payout ■ Potential for financial distress (albeit limited to Project level)
SUMMARY ASSESSMENT	<ul style="list-style-type: none"> ■ Least risky debt alternative for State Project Company; no recourse to the State and potentially minimal impact on the State's credit rating ■ More expensive than other debt alternatives; less expensive than equity alternatives ■ Allows the State to maintain its undiluted ownership and control interest in the State Project Company

¹⁷⁰ Non-recourse debt is the debt structure most commonly associated with project finance.

4. Hybrid Securities (e.g., Convertible Debt)¹⁷¹

DESCRIPTION	<ul style="list-style-type: none"> ■ The State Project Company could issue debt that carries the right to be converted into common shares <ul style="list-style-type: none"> ■ Convertible debt is a type of “hybrid security” (i.e., one which exhibits characteristics of both debt and equity, depending upon conversion of an underlying option) ■ The option to convert debt principal into common shares rests with the holder <ul style="list-style-type: none"> ■ The debt would convert at a negotiated exchange ratio (e.g., a certain amount of principal would be worth a certain number of shares) set when the convertible debt is issued <ul style="list-style-type: none"> – Requires the State Project Company to have a view on the value of its common shares at a future conversion date ■ The option to convert generally expires at the maturity of the debt, although certain types of convertible debt have mandatory conversion and other specialized features ■ Prior to conversion, convertible debt would exhibit the attributes of the debt alternatives discussed above; following conversion, convertible debt would exhibit the attributes of common equity ■ If a conversion option is exercised, common shares of the State Project Company would not expire or mature
BENEFITS	<ul style="list-style-type: none"> ■ Less expensive than equity alternatives, but more expensive than debt alternatives ■ High level of structuring flexibility allows matching of State Project Company and investor goals ■ Attractive to a wider range of investors given the debt and equity features ■ Exhibits the benefits of debt alternatives prior to conversion and the benefits of common equity following conversion <ul style="list-style-type: none"> ■ Could be beneficial if the State Project Company prefers debt attributes in the near term
CONSIDERATIONS	<ul style="list-style-type: none"> ■ Complexities associated with calculating future value of State Project Company when setting exchange ratio upon convertible debt issuance <ul style="list-style-type: none"> ■ Miscalculations could result in not receiving adequate proceeds upon conversion ■ Exhibits the considerations of debt alternatives prior to conversion and the considerations of common equity following conversion <ul style="list-style-type: none"> ■ Could be detrimental if the State Project Company prefers equity attributes in the near term ■ Potentially limited market for convertible debt
SUMMARY ASSESSMENT	<ul style="list-style-type: none"> ■ A type of security that blends the characteristics of debt and equity, thereby producing a more expensive financing choice than other debt alternatives, but a less expensive financing choice than equity alternatives ■ Well-developed area of the capital markets, but more complex than other financing alternatives; in some cases, market for investors can be relatively limited ■ Allows the State Project Company to access a wide range of potential investors

¹⁷¹ Features of common equity described in this section are presented in greater detail in Section VII.B.1.

B. Equity

1. Common Equity

DESCRIPTION	<ul style="list-style-type: none"> ■ The State Project Company could issue common stock to investors¹⁷² <ul style="list-style-type: none"> ■ Common stock represents the most basic form of ownership in an entity ■ Individual units, or shares, of common stock would be issued based on the size of investment and the value of the State Project Company (i.e., the value of the State's interest in the Project)¹⁷³ ■ Common shareholders would be entitled to a residual claim on all assets of the State Project Company, following distributions to any debt holders and preferred equity holders <ul style="list-style-type: none"> ■ Common shareholders would realize a return on their investment via dividends from the State Project Company (i.e., in each operating period, the State Project Company's excess cash flows would be shared among the shareholders based on the number of shares owned) ■ Common shareholders could also realize a return via appreciation in the value of their shares ■ Individual shares would entitle holders to the right to vote on key State Project Company decisions <ul style="list-style-type: none"> ■ In certain cases, different classes of shares could represent a different number of votes (e.g., Class A shares might represent 10 votes, while Class B shares might represent 1 vote) ■ Common shares of the State Project Company would not expire or mature
BENEFITS	<ul style="list-style-type: none"> ■ Relatively more equity in the Project could provide the State with greater flexibility with respect to operating the State Project Company or otherwise, as the Project would be less burdened by required debt service payments (principal and interest) <ul style="list-style-type: none"> ■ The State Project Company would likely make dividend payments to common shareholders; however, the frequency and amount of these payments could vary ■ Long-term view of common shareholders could align with that of State and State Project Company ■ Common shareholders have no recourse to the State ■ Structure of Class A and Class B voting shares could allow the State to retain "control" of the State Project Company while maximizing external equity funding sources ■ The State, as a potential common stock investor in the State Project Company, would be able to share in all of the benefits of ownership (e.g., potential for outsized returns, governance rights, etc.)
CONSIDERATIONS	<ul style="list-style-type: none"> ■ Miscalculation of State Project Company value when issuing shares could result in not receiving adequate proceeds for share issuances ■ Potential dilution of the State's ownership interest in and control of the State Project Company in cases where common equity is sold to third-party investors ■ More expensive than debt alternatives ■ Greater potential complexity associated with the tracking of multiple shareholders and related rights
SUMMARY ASSESSMENT	<ul style="list-style-type: none"> ■ At a minimum, the State Project Company must have some amount of common stock, representative of the entity's ownership (i.e., the State prior to incremental common stock issuance) ■ More expensive than debt alternatives; however, may facilitate optimal capital structure and structuring approaches, which could minimize control and other effects of equity issuances ■ The sale of equity to third parties would result in the dilution of the State's ownership in and control of the State Project Company

¹⁷² Shares could potentially be issued via an initial public offering ("IPO"). An IPO could potentially occur late in Project development, when State Project Company cash flows are more certain. Existing equity holders (e.g., the State) could choose to sell or retain some or all of their shares through the IPO. IPOs have several benefits in addition to those listed above, including the potential for the State to monetize some or all of its ownership interest in the State Project Company, access a broad investor base, and provide a conventional way for Alaska municipalities, individuals and other State entities to invest in the Project. However, an IPO would also be associated with additional compliance, reporting and operating costs.

¹⁷³ In certain situations, limitations on the number and type of potential shareholders may exist.

2. Preferred Equity

DESCRIPTION	<ul style="list-style-type: none"> ■ The State Project Company could issue preferred equity to investors <ul style="list-style-type: none"> ■ Preferred equity represents an ownership interest with debt-like attributes ■ Shares of preferred equity would be issued based on the size of investment and the value of the State Project Company¹⁷⁴ ■ Preferred shareholders would be entitled to a claim on the assets of the State Project Company, but generally only up to the value of their initial investment (the “par value”) <ul style="list-style-type: none"> ■ Preferred shareholders would realize a return on their investment via a negotiated fixed dividend payment from the State Project Company that is distributed after all payments are made to debt holders (i.e., principal and interest payments), but before any payments are made to common equity shareholders <ul style="list-style-type: none"> – Failure to make dividend payments on time would not result in a default scenario (as it would in the case of a missed payment for debt alternatives); however, unpaid dividends generally accrue and must be paid out (with interest) prior to any future dividends to common equity shareholders ■ Preferred shareholders could also realize a return via appreciation in the value of their shares, albeit to a lesser extent than for common shareholders ■ Unlike common shares, preferred shares generally do not entitle holders to the right to vote on key State Project Company decisions, unless specifically structured to do so ■ Preferred shares are typically issued in blocks, and can be structured to accommodate varying investor needs (e.g., level of seniority, convertibility into common shares, ability to participate in earnings upside, etc.) ■ Preferred shares of the State Project Company would not expire or mature, but could be callable (i.e., able to be repurchased by the State Project Company at a premium to par value)
BENEFITS	<ul style="list-style-type: none"> ■ Relatively more equity in the Project could provide the State with greater flexibility with respect to operating the State Project Company or otherwise, as the Project would be less burdened by required debt service payments (principal and interest) <ul style="list-style-type: none"> ■ The State Project Company would still be required to make fixed dividend payments to preferred shareholders, but would not be at risk of a default scenario in the event of nonpayment ■ Long-term view of preferred shareholders could align with that of the State and State Project Company <ul style="list-style-type: none"> ■ High level of structuring flexibility allows matching of State Project Company and investor goals ■ Preferred shareholders have no recourse to the State ■ No dilution of the State’s ownership interest in the State Project Company ■ The absence of voting rights would allow the State to retain control of the State Project Company ■ Callable feature gives the State Project Company the option to reduce fixed dividend payments
CONSIDERATIONS	<ul style="list-style-type: none"> ■ Miscalculation of State Project Company value when issuing shares could result in not receiving adequate proceeds for share issuances ■ More expensive than debt alternatives, albeit less expensive than common equity ■ Greater potential complexity associated with the tracking of multiple shareholders and related rights
SUMMARY ASSESSMENT	<ul style="list-style-type: none"> ■ Preferred equity is a debt-like equity security that would allow the State Project Company to structure its financing in a way that likely does not impact the State’s credit rating ■ More expensive than debt alternatives; however, preferred stock is less expensive than common equity and preserves for the State operational flexibility and control/governance rights ■ Allows the State to maintain its undiluted ownership in and control of the State Project Company

¹⁷⁴ In certain situations, limitations on the number and type of potential shareholders may exist.

3. Warrants

<p>DESCRIPTION</p>	<ul style="list-style-type: none"> ■ The State Project Company could issue rights to investors to buy common shares of the State Project Company at a later date, for an upfront payment (warrant premium) <ul style="list-style-type: none"> ■ A warrant represents a right to buy common shares in an entity at a set price ■ The option to exercise the warrant (i.e., to buy common shares) rests with the holder <ul style="list-style-type: none"> ■ The price that the warrant holder would be required to pay for common shares (i.e., the exercise price) would be negotiated and set when the warrant is issued <ul style="list-style-type: none"> – This exercise price would typically be “out-of-the-money” at the time of warrant issuance, which means that it would be higher than the currently implied value of a common share; as the value of the State Project Company increases with time and exceeded the exercise price, the warrant holder would likely exercise their right to purchase common shares (at the exercise price) – Requires the State Project Company to have a view on the value of its common shares at a potential future warrant exercise date ■ The option to exercise the warrant would expire at a negotiated expiration date ■ Prior to exercise, warrants would have minimal, if any, impact on the State Project Company; following exercise, warrants would exhibit the attributes of common equity ■ If the warrant is exercised, common shares of the State Project Company would not expire or mature
<p>BENEFITS</p>	<ul style="list-style-type: none"> ■ Allows the State Project Company to receive an upfront premium without any immediate equity dilution ■ Potentially less expensive than other equity alternatives, as the State can raise capital without any immediate payments ■ Warrants could potentially be added as a “sweetener” to other securities (e.g., debt or preferred equity), to secure more favorable terms (e.g., lower interest or dividend payments, fewer covenants, etc.) ■ Exhibits the benefits of common equity following exercise <ul style="list-style-type: none"> ■ Could be beneficial if the State Project Company prefers equity attributes in the long term
<p>CONSIDERATIONS</p>	<ul style="list-style-type: none"> ■ Potentially difficult to raise a significant amount of capital ■ More expensive than debt alternatives, albeit less expensive than common equity ■ Complexities associated with calculating future value of State Project Company when setting exercise price upon warrant issuance <ul style="list-style-type: none"> ■ Miscalculations could result in not receiving adequate proceeds upon exercise ■ Exhibits the considerations of common equity following exercise <ul style="list-style-type: none"> ■ Could be detrimental if the State Project Company prefers equity attributes in the near term
<p>SUMMARY ASSESSMENT</p>	<ul style="list-style-type: none"> ■ Allow the State Project Company to raise some level of capital while deferring any potential ownership/control dilution ■ Potentially preferable to common equity, depending on the exercise price, scope and benefits to other financing efforts

VIII Preliminary Selected Evaluative Criteria

VIII. Preliminary Selected Evaluative Criteria

The Final Report will provide specific analysis and recommendations with respect to the Project funding sources and financing alternatives¹⁷⁵ available to the State. The various funding sources and financing alternatives will be evaluated against the following criteria, among others, to develop a recommended financing approach for the State:

	DESCRIPTION
POTENTIAL IMPACT ON DEBT CAPACITY/ OPPORTUNITY COST	<ul style="list-style-type: none"> ■ How does the proposed financing alternative potentially limit the State’s ability to issue debt or allocate funds to other priorities? <ul style="list-style-type: none"> ■ The State has a finite capacity to issue debt, and to the extent that it wishes to issue debt for other purposes, this capacity may be limited depending on how much debt is issued for the Project ■ The State’s funds (e.g., the Permanent Fund) invest in a variety of different securities; diverting dollars to invest in the Project means that these dollars are not available for other fund investments
POTENTIAL IMPACT ON ALASKA CREDIT RATING	<ul style="list-style-type: none"> ■ How does the proposed financing alternative impact the State’s credit rating? <ul style="list-style-type: none"> ■ Increasing the amount of State debt could potentially result in rating agency downgrades ■ A decrease in the State’s credit rating could constrain future efforts by the State to access the capital markets and could raise the State’s overall cost of debt
KEY RISKS	<ul style="list-style-type: none"> ■ How much/what types of key risks are involved with respect to the State undertaking the proposed financing alternative? <ul style="list-style-type: none"> ■ Potential for default, financial distress and loss of operational flexibility for debt structuring alternatives ■ Potential for the State to lose all or a portion of its investment in the Project ■ Potential for lenders to have recourse to State assets
COST	<ul style="list-style-type: none"> ■ What is the potential cost of securing the financing and providing a return to debt and equity investors? <ul style="list-style-type: none"> ■ Interest rate for funding alternatives and debt structuring ■ Required return for funding alternatives and equity structuring ■ Issuance, structuring and other fees (e.g., payments to underwriters, lawyers, financial advisors, etc.)
EXECUTION FLEXIBILITY/ FEASIBILITY	<ul style="list-style-type: none"> ■ How difficult will it likely be for the State to execute its preferred financing structure? <ul style="list-style-type: none"> ■ Certain types of financing structures are easier to implement than others, including with respect to facilitating investment participation by State residents, corporations and municipalities ■ Certain types of funding sources are more accessible than others ■ Certain provisions (e.g., debt covenants) can potentially be restrictive and limit the State’s flexibility
ALIGNMENT OF INTERESTS AMONG KEY PARTIES	<ul style="list-style-type: none"> ■ Are the interests of the various key parties aligned? <ul style="list-style-type: none"> ■ Certain financing alternatives and/or funding sources may introduce Project misalignment, conflicts of interest or other forms of dysfunction for sponsors

¹⁷⁵ Inclusive of any potential terms and conditions.

IX Recommended Next Steps

IX. Recommended Next Steps

In preparation for the delivery of the Final Report in Fall 2015, Lazard will focus on the following areas of analysis and interaction, among others:

- Participation in State legislative session during Spring 2015
- Continued monitoring of global LNG market dynamics
 - Update of Black & Veatch Model to reflect, among other items, current commodity pricing environment¹⁷⁶
- Continued monitoring of Project developments (e.g., offtake agreements, partnership agreement, etc.) and potential impacts on analysis of financing alternatives
- Further analysis of potential sources of funds
 - Interaction with various State and external fund providers to gauge interest in Project participation
 - Identification of preferred sources of funds via analysis and interaction with key stakeholders, including the Alaska Legislature
- Further analysis of potential structuring alternatives
 - Identification of preferred structuring alternatives via analysis and interaction with key stakeholders, including the Alaska Legislature
- Further refinement of evaluative criteria
- Formation of potential financing alternatives (i.e., combinations of sources of funds and structuring alternatives)
- Analysis of implementation issues associated with potential financing alternatives
 - Legislative
 - Regulatory
 - Legal
 - Execution
 - Other
- Assessment of financing alternatives against evaluative criteria
- Identification of optimal financing alternatives via iterative process (i.e., in consideration of evaluative criteria, implementation issues and other factors)
- Drafting of Final Report
 - Continued iteration and interaction with the Department of Revenue and State advisors

¹⁷⁶ Current Black & Veatch Model is dated February 2014.

X Preliminary Conclusions and Observations

X. Preliminary Conclusions and Observations

The State has determined that a direct investment in a large-scale LNG export project should be an important part of Alaska's fiscal future. While declining Alaska production and global oil prices threaten to create significant budget shortfalls in the near term (the State expects to deplete its current \$15 billion budget reserve funds by 2022/2023), the Project has the potential to provide a much needed new revenue source that could help to support the State's budget. Numerous features of the global LNG market, together with factors specific to the Project, support the investment, including projected demand growth in Pacific Rim countries, the State's strategic access to these markets and the quality and abundance of the State's natural gas reserves.

Given the State's determination to pursue a large-scale LNG export project, the State should consider a variety of factors as it determines how it could potentially finance an endeavor of this magnitude (as much as \$13.7 billion would be required under the State's currently contemplated 25% ownership stake). For example, there exist a number of funding sources that can be called upon by the State to fund its investment in the Project; these funding sources include those under the State's control (e.g., the Permanent Fund), those of Alaska entities and individuals and those of external investors. Additionally, the State must consider the equity and debt capitalization of its investment in the Project and what types of structures (e.g., non-recourse debt, common equity, etc.) are most beneficial, while also considering a number of potential evaluative criteria. In general, the State should seek an "optimal" structure that limits its overall cost of financing while also taking into account other evaluative criteria, including impact on the State's debt capacity and credit rating, risk, feasibility and the alignment of interests among key parties.

Over the next several months, in preparation for the delivery of the Final Report in Fall 2015, Lazard will further analyze the concepts introduced in this Report and will work with various stakeholders (including the Department of Revenue, other State advisors and the Alaska Legislature) to identify and formulate optimal financing recommendations for the State's participation in the Project.

XI Appendix Materials

XI. Appendix Materials

A. Preliminary Cost of Capital Data

The State Project Company's weighted average cost of capital would be determined based on the relative amounts of debt and equity in its capital structure, and their respective costs. An illustrative implied cost of equity can be derived via the CAPM, which utilizes observed market betas¹⁷⁷ of publicly-traded companies that have approximately similar risk profiles as the State Project Company. Since the Project has no directly-comparable publicly-traded peers, Lazard evaluated various categories of publicly-traded companies that engage in activities similar to those of the Project (e.g., LNG companies, oil and gas producers, EPC companies and pipeline operators) to derive an illustrative implied cost of equity. The State Project Company's cost of debt will vary based on several factors (e.g., term, size, issuing entity, credit quality, structure, covenants, etc.); however, an illustrative range for the cost of debt can be derived from observing the cost of debt for various comparable historical borrowings across several different categories of debt (e.g., general obligation bonds, revenue bonds, tax-exempt bonds and project financings), as presented in the following sections.

¹⁷⁷ Beta is a measure of risk arising from exposure to general market movements. A beta below 1 typically indicates an asset with lower volatility than the market, and/or a volatile asset whose price movements are not highly correlated with the market. A beta above 1 generally means that the asset is both volatile and tends to move up and down with the market.

1. Cost of Equity

a. LNG Companies¹⁷⁸

COMPARABLE COMPANIES	ENTERPRISE VALUE	NET DEBT	NET DEBT/ ENT. VALUE	NET DEBT/ EQUITY VALUE	LEVERED BETA ¹⁷⁹	UNLEVERED BETA ¹⁸⁰
Cheniere	\$26,863	\$10,680	39.76%	66.00%	1.621	0.996
		Median	39.76%	66.00%	1.621	0.996
		Mean	39.76%	66.00%	1.621	0.996

ASSUMPTIONS		SENSITIVITY RANGE		IMPLIED COST OF EQUITY	
		LOW	HIGH	LOW	HIGH
Unlevered Beta ¹⁸⁰	0.996	0.996	0.996	11.95%	11.95%
Target Debt/Capitalization	35.00%	25.00%	45.00%	11.03%	13.21%
Levered Beta ¹⁸¹	1.345				
Marginal Tax Rate	35.00%	35.00%	0.00%	11.95%	13.26%
Risk Free Rate of Return ¹⁸²	2.59%				
Equity Risk/Market Premium ¹⁸³	6.96%				
Cost of Equity¹⁸⁴				11.95%	

Sources: Barra, Wall Street research, FactSet and Company filings.

¹⁷⁸ Potential entities for further study and/or inclusion in this list include Sempra's LNG business, Dominion's LNG business and non-U.S. based LNG businesses, among others.

¹⁷⁹ Betas as of December 31, 2014.

¹⁸⁰ Unlevered Beta = Levered Beta/[1+(1-Tax Rate)(Debt/Equity)].

¹⁸¹ Levered Beta = (Unlevered Beta)[1+(1-Tax Rate)(Debt/Equity)].

¹⁸² Risk Free Rate is 30-Year Treasury Bond Yield as of January 8, 2015.

¹⁸³ Represents the long-horizon expected equity risk premium based on differences of historical arithmetic mean returns on the S&P 500 from 1926 – 2013 (Ibbotson Associates' 2014 Yearbook).

¹⁸⁴ Cost of Equity = (Risk Free Rate of Return) + (Levered Beta)(Equity Risk Premium).

b. Oil and Gas Producers

COMPARABLE COMPANIES	ENTERPRISE VALUE	NET DEBT	NET DEBT/ ENT. VALUE	NET DEBT/ EQUITY VALUE	LEVERED BETA ¹⁸⁵	UNLEVERED BETA ¹⁸⁶
BP	\$134,098	\$19,548	14.58%	17.44%	1.116	1.002
Chevron	221,778	11,219	5.06%	5.38%	1.106	1.069
Conoco	96,788	15,405	15.92%	19.27%	1.278	1.136
Exxon	417,273	16,820	4.03%	4.31%	0.961	0.935
Royal Dutch Shell	235,092	23,374	9.94%	18.27%	1.063	0.950
Median			9.94%	17.44%	1.106	1.002
Mean			9.91%	12.93%	1.105	1.018

ASSUMPTIONS		SENSITIVITY RANGE		IMPLIED COST OF EQUITY	
		LOW	HIGH	LOW	HIGH
Unlevered Beta ¹⁸⁶	1.018	0.935	1.136	10.16%	11.78%
Target Debt/Capitalization	20.00%	10.00%	30.00%	10.19%	11.65%
Levered Beta ¹⁸⁷	1.184				
Marginal Tax Rate	35.00%	35.00%	0.00%	10.83%	11.45%
Risk Free Rate of Return ¹⁸⁸	2.59%				
Equity Risk/Market Premium ¹⁸⁹	6.96%				
Cost of Equity¹⁹⁰	10.83%				

Source: Barra, Wall Street research, FactSet and Company filings.

¹⁸⁵ Betas as of December 31, 2014.

¹⁸⁶ Unlevered Beta = Levered Beta / [1 + (1 - Tax Rate)(Debt/Equity)].

¹⁸⁷ Levered Beta = (Unlevered Beta)[1 + (1 - Tax Rate)(Debt/Equity)].

¹⁸⁸ Risk Free Rate is 30-Year Treasury Bond Yield as of January 8, 2015.

¹⁸⁹ Represents the long-horizon expected equity risk premium based on differences of historical arithmetic mean returns on the S&P 500 from 1926 – 2013 (Ibbotson Associates' 2014 Yearbook).

¹⁹⁰ Cost of Equity = (Risk Free Rate of Return) + (Levered Beta)(Equity Risk Premium).

c. EPC Companies

COMPARABLE COMPANIES	ENTERPRISE VALUE	NET DEBT	NET DEBT/ ENT. VALUE	NET DEBT/ EQUITY VALUE	LEVERED BETA ¹⁹¹	UNLEVERED BETA ¹⁹²
Chicago Bridge & Iron	\$6,687	\$1,970	29.46%	43.73%	1.846	1.437
Fluor	8,123	(1,541)	(18.97%)	(16.50%)	1.462	1.638
KBR	1,437	(985)	(68.54%)	(40.51%)	1.653	2.244
Quanta	6,109	(59)	(0.97%)	(0.97%)	1.429	1.438
Technip	6,188	(943)	(15.24%)	(14.54%)	1.243	1.373
Willbros	465	192	41.37%	70.14%	1.973	1.355
		Median	(8.11%)	(7.75%)	1.557	1.438
		Mean	(5.48%)	6.89%	1.601	1.581

ASSUMPTIONS		SENSITIVITY RANGE		IMPLIED COST OF EQUITY	
		LOW	HIGH	LOW	HIGH
Unlevered Beta ¹⁹²	1.581	1.373	2.244	13.24%	20.00%
Target Debt/Capitalization	15.00%	5.00%	25.00%	13.97%	15.98%
Levered Beta ¹⁹³	1.762				
Marginal Tax Rate	35.00%	35.00%	0.00%	14.86%	15.54%
Risk Free Rate of Return ¹⁹⁴	2.59%				
Equity Risk/Market Premium ¹⁹⁵	6.96%				
Cost of Equity¹⁹⁶	14.86%				

Sources: Barra, Wall Street research, FactSet and Company filings.

¹⁹¹ Betas as of December 31, 2014.

¹⁹² Unlevered Beta = Levered Beta/[1+(1-Tax Rate)(Debt/Equity)].

¹⁹³ Levered Beta = (Unlevered Beta)[1+(1-Tax Rate)(Debt/Equity)].

¹⁹⁴ Risk Free Rate is 30-Year Treasury Bond Yield as of January 8, 2015.

¹⁹⁵ Represents the long-horizon expected equity risk premium based on differences of historical arithmetic mean returns on the S&P 500 from 1926 – 2013 (Ibbotson Associates' 2014 Yearbook).

¹⁹⁶ Cost of Equity = (Risk Free Rate of Return) + (Levered Beta)(Equity Risk Premium).

d. Pipeline Operators

COMPARABLE COMPANIES	ENTERPRISE VALUE	NET DEBT	NET DEBT/ ENT. VALUE	NET DEBT/ EQUITY VALUE	LEVERED BETA ¹⁹⁷	UNLEVERED BETA ¹⁹⁸
Enbridge	\$73,989	\$33,790	45.67%	84.06%	1.169	0.756
ONEOK	19,613	10,190	51.96%	108.14%	1.321	0.776
Spectra	39,117	16,199	41.41%	70.68%	1.014	0.695
TransCanada	59,991	27,041	45.08%	82.07%	1.117	0.728
Williams	64,489	32,191	49.92%	99.67%	1.250	0.759
Median			45.67%	84.06%	1.169	0.756
Mean			46.81%	88.92%	1.174	0.743

ASSUMPTIONS		SENSITIVITY RANGE		IMPLIED COST OF EQUITY	
		LOW	HIGH	LOW	HIGH
Unlevered Beta ¹⁹⁸	0.743	0.695	0.776	10.00%	10.86%
Target Debt/Capitalization	45.00%	35.00%	55.00%	9.57%	11.87%
Levered Beta ¹⁹⁹	1.138				
Marginal Tax Rate	35.00%	35.00%	0.00%	10.51%	11.99%
Risk Free Rate of Return ²⁰⁰	2.59%				
Equity Risk/Market Premium ²⁰¹	6.96%				
Cost of Equity²⁰²	10.51%				

Sources: Barra, Wall Street research, FactSet and Company filings.

¹⁹⁷ Betas as of December 31, 2014.

¹⁹⁸ Unlevered Beta = Levered Beta/[1+(1-Tax Rate)(Debt/Equity)].

¹⁹⁹ Levered Beta = (Unlevered Beta)[1+(1-Tax Rate)(Debt/Equity)].

²⁰⁰ Risk Free Rate is 30-Year Treasury Bond Yield as of January 8, 2015.

²⁰¹ Represents the long-horizon expected equity risk premium based on differences of historical arithmetic mean returns on the S&P 500 from 1926 – 2013 (Ibbotson Associates' 2014 Yearbook).

²⁰² Cost of Equity = (Risk Free Rate of Return) + (Levered Beta)(Equity Risk Premium).

2. Cost of Debt Precedents

a. Alaska Tax-exempt General Obligation Bonds

FINANCING DATE	ISSUER	TERM	YIELD	SIZE (\$ IN MILLIONS)	MOODY'S RATING	GENERAL USE OF PROCEEDS
Aaa Rated						
01/23/2013	Alaska	12.5	1.950%	150	Aaa	Education
02/08/2012	Alaska	11.5	2.000%	176	Aaa	General Purpose
05/29/2008	Alaska Industrial Development & Export Authority	18.9	0.000%	107	Aaa	Industrial Development
04/15/2008	Alaska Municipal Bond Bank	30.0	5.200%	62	Aaa	General Purpose
05/18/2005	Alaska Housing Finance Corp	25.6	4.789%	164	Aaa	Multi Family Housing
Aa2 Rated						
02/20/2014	Alaska Municipal Bond Bank	25.0	4.250%	47	Aa2	General Purpose
11/14/2013	Alaska Municipal Bond Bank	34.7	4.600%	72	Aa2	General Purpose
03/12/2013	Alaska Municipal Bond Bank	33.9	3.460%	96	Aa2	General Purpose
05/24/2012	Alaska Municipal Bond Bank	19.3	3.500%	53	Aa2	General Purpose
09/15/2011	Alaska Municipal Bond Bank	25.0	4.300%	78	Aa2	General Purpose
04/14/2009	Alaska	20.3	4.680%	165	Aa2	Transportation

Sources: Bloomberg and EMMA

WEIGHTED AVERAGE YIELD (EXCLUDING ZERO YIELD ISSUANCES)	
Aaa Rated	3.174%
Aa2 Rated	4.220%

b. Alaska Tax-exempt Revenue Bonds

FINANCING DATE	ISSUER	TERM	YIELD	SIZE (\$ IN MILLIONS)	MOODY'S RATING	GENERAL USE OF PROCEEDS
Aaa Rated						
11/22/2011	Alaska Housing Finance Corp	14.5	3.750%	71	Aaa	Single Family Housing
09/30/2010	Alaska Housing Finance Corp	30.2	4.625%	79	Aaa	Single Family Housing
10/03/2007	Alaska Housing Finance Corp	22.2	4.430%	96	Aaa	Transportation
08/29/2007	Alaska Railroad Corporation	13.9	5.000%	89	Aaa	Transportation
10/25/2006	Alaska Housing Finance Corp	33.6	4.660%	101	Aaa	Single Family Housing
08/22/2006	Alaska Railroad Corporation	15.0	4.320%	76	Aaa	Transportation
04/26/2006	Alaska	19.9	4.850%	68	Aaa	General Purpose
03/14/2006	Alaska	21.6	4.320%	176	Aaa	Airports
02/02/2006	CivicVentures	32.6	4.770%	111	Aaa	General Purpose
03/30/2005	Alaska Student Loan Corp	9.3	3.970%	88	Aaa	Student Loans
01/01/2005	Alaska Housing Finance Corp	36.9	4.540%	143	Aaa	Single Family Housing
10/28/2004	Alaska Industrial Development & Export Authority	29.4	0.000%	120	Aaa	Health Care
03/11/2004	Alaska Student Loan Corp	14.3	4.093%	75	Aaa	Student Loans
03/04/2004	Alaska Housing Finance Corp	28.8	4.750%	52	Aaa	Multi Family Housing
12/05/2002	Alaska Housing Finance Corp	21.6	0.000%	60	Aaa	Multi Family Housing
10/01/2002	Alaska Housing Finance Corp	37.7	4.950%	150	Aaa	Single Family Housing
09/05/2002	Alaska Housing Finance Corp	30.3	0.000%	79	Aaa	Multi Family Housing
04/01/2002	Alaska International Airport System	25.5	5.430%	128	Aaa	Airports
08/15/2001	Northern Tobacco Securitization Corp	27.8	5.620%	127	Aaa	General Purpose
08/02/2001	Alaska Housing Finance Corp	29.4	0.000%	77	Aaa	Single Family Housing
08/02/2001	Alaska Housing Finance Corp	29.4	0.000%	94	Aaa	Single Family Housing
02/01/2001	Alaska Housing Finance Corp	6.3	4.050%	75	Aaa	Single Family Housing
11/01/2000	Alaska Housing Finance Corp	40.1	6.00%	62	Aaa	Single Family Housing

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FINANCING DATE	ISSUER	TERM	YIELD	SIZE (\$ IN MILLIONS)	MOODY'S RATING	GENERAL USE OF PROCEEDS
06/01/2000	Alaska Housing Finance Corp	39.0	6.450%	56	Aaa	Single Family Housing
Aa1 Rated						
09/17/2014	Alaska	14.7	3.020%	31	Aa1	Health Care
Aa2 Rated						
11/17/2011	Alaska Industrial Development & Export Authority	29.9	4.830%	123	Aa2	Health Care
02/16/2011	Alaska Housing Finance Corp	16.8	5.020%	105	Aa2	General Purpose
08/26/2009	Alaska Housing Finance Corp	30.3	5.350%	81	Aa2	Single Family Housing
08/26/2009	Alaska Housing Finance Corp	31.3	0.000%	81	Aa2	Single Family Housing
05/28/2009	Alaska Housing Finance Corp	1.5	0.000%	81	Aa2	Single Family Housing
05/28/2009	Alaska Housing Finance Corp	1.5	0.000%	81	Aa2	Single Family Housing
09/30/2008	Alaska Housing Finance Corp	30.2	5.530%	81	Aa2	Single Family Housing
05/31/2007	Alaska Housing Finance Corp	34.5	0.000%	75	Aa2	Single Family Housing
05/31/2007	Alaska Housing Finance Corp	34.5	0.000%	75	Aa2	Single Family Housing
05/31/2007	Alaska Housing Finance Corp	34.5	0.000%	89	Aa2	Single Family Housing
11/30/2006	Alaska Industrial Development & Export Authority	29.9	4.380%	54	Aa2	Health Care
Aa3 Rated						
10/26/2000	Northern Tobacco Securitization Corp	30.6	6.600%	116	Aa3	General Purpose
A1 Rated						
02/24/2010	Alaska Industrial Development & Export Authority	17.1	4.500%	87	A1	Seaports/Marine Terminals

Sources: Bloomberg and EMMA.

WEIGHTED AVERAGE YIELD (EXCLUDING ZERO YIELD ISSUANCES)	
Aaa Rated	4.751%
Aa1 Rated	3.020%
Aa2 Rated	5.043%
Aa3 Rated	6.600%
A1 Rated	4.500%

c. Selected Precedent Taxable (Non-recourse) Project Financings

FINANCING DATE	PROJECT NAME	DEBT TERMS	PROJECT DESCRIPTION/NOTES
10/31/2014	Freeport LNG Export Project (Train 1 ²⁰³)	<p>Tranche 1 Size: \$2.6 billion Term Loan Pricing: L+200</p> <p>Tranche 2 Size: \$1.2 billion Term Loan Pricing: L+200</p> <p>Tranche 3 Size: \$100 million Term Loan</p>	The Freeport, Texas-based Freeport LNG Project was originally launched in 2008 as an import terminal. In July 2014, it received FERC approval to construct and operate facilities in order to export LNG. Project financing for Train 1 was completed in Fall 2014.
08/06/2014	Cameron LNG Export Project	<p>Tranche 1 Size: \$2.9 billion Term Loan Pricing: L+175 Term: 16 years Credit Rating: A/A3</p> <p>Tranche 2 Size: \$2.5 billion Term Loan Pricing: L+125 Term: 16 years Credit Rating: A</p> <p>Tranche 3 Size: \$2.0 billion Term Loan Pricing: L+175 Term: 16 years Credit Rating: A</p> <p>Tranche 4 Size: \$350 million Standby Letter of Credit</p>	Originally constructed as an import terminal, in 2011 Cameron LNG proposed adding export capabilities to its facilities in Hackleberry, Louisiana. In 2014, the project gained approval to export up to 12 MTPA of domestic LNG. The project is majority owned by Semptra, with GDF Suez, Sumimoto Mitsui Financial Group, Mitsubishi and Nippon Yusen K.K. the other owners.
05/28/2013	Sabine Pass Liquefaction	<p>Tranche 1 Size: \$2.0 billion Senior Notes Pricing: 5.625% Term: 8 years</p> <p>Tranche 2 Size: \$1.0 billion Senior Notes Pricing: 6.250% Term: 9 years</p> <p>Tranche 3 Size: \$1.5 billion Senior Notes Pricing: 5.625% Term: 10 years</p> <p>Tranche 4 Size: \$2.0 billion Senior Notes Pricing: 5.750% Term: 10 years</p>	Cheniere-owned Sabine Pass was originally constructed in 2008 as an import terminal, but has since altered its strategy, and intends to begin exporting LNG by 2016. Its Senior Notes issuances in 2013 and 2014 back the construction of Trains 1 – 4. To fully finance the remaining trains, additional debt or equity will likely be needed.
05/03/2010	Ruby Pipeline	<p>Tranche 1 Size: \$25 million Revolver Pricing: L+300 Term: 7 years</p> <p>Tranche 2 Size: \$1.5 billion Term Loan Pricing: L+300 Term: 7 years</p>	Ruby Pipeline, located in Colorado Springs, Colorado, owns and operates a 680-mile natural gas transmission pipeline system. It has a current capacity of approximately 1.5 Bcf/d, with expansion potential to 2.0 Bcf/d. In May 2010, Ruby Pipeline secured a \$1.5 billion loan financing to support construction costs.

²⁰³ An LNG train is an LNG plant's liquefaction and purification facility.

FINANCING DATE	PROJECT NAME	DEBT TERMS	PROJECT DESCRIPTION/NOTES
02/07/2008	LNG Clean Energy	Tranche 1 Size: \$870 million Term Loan Pricing: L+150 Term: 14 years	LNG Clean Energy's 2008 debt issuance backed the \$1.1 billion construction of LNG Clean Energy, an import terminal on the Port of Pascagoula in Mississippi.
12/16/2004	Qatargas 2	Tranche 1 Size: \$1.1 billion Term Loan Term: 25 years Tranche 2 Size: \$530 million Islamic Financing Term: 156 years Tranche 3 Size: \$800 million Export Credit Facility Tranche 4 Size: \$5.2 billion Term Loan	Exxon and Qatar Petroleum-owned Qatargas 2's 2004 \$7.6 billion project financing was the largest energy project financing in the world at the time. The project involves construction of two trains, the acquisition of several LNG carriers and construction of a receiving terminal in the U.K.

Sources: Bloomberg, FERC, LoanConnector and S&P Leveraged Commentary and Data.

d. Selected Precedent Taxable (Recourse) Financings

FINANCING DATE	ISSUER	DEBT TERMS	MOODY'S RATING
04/30/13	Sterling Resources	Tranche 1: Size: \$300 million Pricing: 9.000% Revenue Bonds Term: 7.0 Years	NR
04/23/13	Transportadora de Gas del Peru	Tranche 1: Size: \$850 million Pricing: 4.250% Senior Unsecured Notes Term: 15.0 Years	Baa2
03/19/13	IGas Energy	Tranche 1: Size: \$165 million Pricing: 10.000% Senior Secured Notes Term: 5.0 Years	NR
02/04/13	Geopark Chile	Tranche 1: Size: \$300 million Pricing: 7.500% Guaranteed Bonds Term: 7.0 Years	NR
11/17/09	State of Qatar	Tranche 1: Size: \$7.0 billion Senior Notes Pricing: 5.250% Term: 10.2 Years Tranche 2: Size: \$7.0 billion Senior Notes Pricing: 6.400% Term: 30.2 Years Tranche 3: Size: \$5.2 billion Senior Notes Pricing: 4.000% Term: 5.2 Years	Aa2
07/23/09	Dolphin Energy	Tranche 1: Size: \$1.3 billion Pricing: 5.888% Senior Secured Notes Term: 9.9 Years	Aa3
07/22/09	Georgia Municipal Gas Authority	Tranche 1: Size: \$100 million Pricing: Revenue Bonds, coupon range 2.571% – 4.037% Term: 4.1 Years	A1

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FINANCING DATE	ISSUER	DEBT TERMS	MOODY'S RATING
07/16/09	Ras Laffan Liquefied Natural Gas Co.	Tranche 1: Size: \$2.3 billion Guaranteed Senior Secured Notes Pricing: 6.750% Term: 10.2 Years Tranche 2: Size: \$2.3 billion Guaranteed Senior Secured Notes Pricing: 5.500% Term: 5.2 Years Tranche 3: Size: \$2.3 billion Guaranteed Senior Secured Notes Pricing: 4.500% Term: 3.2 Years	Aa2
06/02/09	City of San Antonio	Tranche 1: Size: \$375 million Pricing: 5.985% Revenue Bonds Term: 29.7 Years	Aa1
05/11/09	Maritimes & NE Pipeline	Tranche 1: Size: \$500 million Pricing: 7.500% Global Bonds Term: 5.0 Years	Baa3

Sources: LoanConnector and S&P Leveraged Commentary and Data.

B. Precedent LNG Export Projects

The following are examples of LNG export projects that either have been completed or are in the late stages of development. These examples are included to provide background on the financing and structuring decisions of projects similar to the AKLNG Project.

1. Sabine Pass Liquefaction LNG Project

a. Overview of Project

The Sabine Pass LNG Liquefaction Project (“Sabine Pass” or “Sabine Pass Liquefaction”), located in Cameron Parish, Louisiana, is the first LNG export facility in the Lower 48. The terminal was originally constructed by Cheniere Energy Partners, L.P. (“Cheniere”) in 2008 as an LNG import facility with unloading and regasification capabilities. However, due to a sharp increase in domestic shale gas production, the U.S.’s need for imported LNG has drastically reduced since 2008. This shift in need initially called into question the potential for profitability at Sabine Pass.²⁰⁴

Cheniere has since pivoted its Sabine Pass strategy and is currently developing liquefaction capabilities and export terminals at the site with a targeted in-service date (“ISD”) of early 2016. The Sabine Pass location is well-positioned to provide LNG export services due to its proximity to shale gas in Louisiana and Texas, its access to the Gulf Coast and its existing interconnections with multiple pipelines. As a result of this conversion, Sabine Pass is expected to be the first joint import/export terminal in the world. The liquefaction expansion project is expected to cost \$12 billion for the first four trains and to have a capacity of ~18 MTPA.²⁰⁵

Sabine Pass has currently contracted out its output to a variety of offtakers, including Japanese firms such as Chubu Electric and Kansai Electric Power, as well as European firms such as Total and Centrica.

Cheniere is a publicly-traded LNG project developer and operator based in Houston; the firm has a market capitalization of approximately \$17 billion.²⁰⁶

²⁰⁴ “Shale Gas: Terminal Decline No Longer,” Financial Times, April 23, 2012.

²⁰⁵ “Sabine Pass LNG Expansion Benefits Highlighted,” LNG Industry, September 19, 2014.

²⁰⁶ FactSet.

b. Map of Assets



Source: Cheniere.

c. Overview of Financing

Cheniere is targeting a 65/35 debt-to-equity ratio to finance Sabine Pass.²⁰⁷

Equity in Sabine Pass has been contributed by Cheniere and Blackstone. Cheniere financed a \$500 million equity stake in the project through sales of equity at the parent company level to two Asian investment firms in early 2012.²⁰⁸ A Blackstone-led consortium of private investors raised the remaining \$1.5 billion of equity in mid-2012. Blackstone’s equity investment is structured using a special type of “payment in kind” accreting equity that is convertible into common equity in Cheniere’s Sabine Pass subsidiary. This structure allowed Blackstone to gain several seats on the subsidiary’s board.²⁰⁹

Cheniere has also secured ~\$6.5 billion in debt financing. The senior note financing that Cheniere utilized has covenants on issuing additional debt or preferred stock, distributing capital, and selling or transferring assets, and is secured concerning a *pari passu* basis by all of Sabine Pass Liquefaction’s assets. Sabine Pass Liquefaction may make distributions only after certain conditions have been satisfied, including the substantial completion of the first two LNG trains and the achievement of a projected debt service coverage ratio of 1.25x. The senior notes also carry a “make-whole” provision that allows the company to redeem the senior notes at a “make-whole” price²¹⁰ plus any accrued or unpaid interest.²¹¹

²⁰⁷ “Non-recourse construction/term loan - Cheniere Energy Partners,” Société Générale, October 8, 2012.

²⁰⁸ “Temasek, RRJ Capital to Invest in Cheniere Energy,” Wall Street Journal, May 7, 2012.

²⁰⁹ Cheniere Energy Partners, LP company filings.

²¹⁰ A borrower often can repay certain types of debt early at a premium called the “make-whole” price.

²¹¹ Cheniere company filings.

Sabine Pass secured a \$5.9 billion credit facility in 2013 and a \$325 million letter of credit reimbursement agreement, but as of September 2014, the company was not borrowing any money from either facility. The credit facility was priced on a floating basis at a 2.3% – 3.0% spread to LIBOR prior to completion of the fourth liquefaction train and priced at 2.3% – 3.5% spread thereafter. The credit facility was structured such that, as Cheniere issues additional senior notes, the size of the credit facility commitment available will decrease. As of September 30, 2014, \$2.7 billion of the credit facility was available.²¹²

SABINE PASS LIQUEFACTION CAPITALIZATION TABLE (\$ IN BILLIONS)²¹³			
SECURITY	AMOUNT	PRICING	TERM
Equity			
Cheniere Equity	\$0.5	NA	NA
Blackstone-led Consortium Equity	1.5	NA	NA
Total Equity	\$2.0		
Debt			
2021 Senior Notes (Project Finance)	\$2.0	5.625%	8 years
2022 Senior Notes (Project Finance)	1.0	6.250%	9 years
2023 Senior Notes (Project Finance)	1.5	5.625%	10 years
2024 Senior Notes (Project Finance)	2.0	5.750%	10 years
Total Debt	\$6.5		

Source: Company filings, LoanConnector and news releases.

²¹² Cheniere Energy Partners, LP company filings.

²¹³ The table displays all debt outstanding and equity invested in Sabine Pass Liquefaction. To fully finance the entire project (e.g., Trains 1 – 6), Cheniere will likely need to issue incremental debt or equity.

2. Gorgon LNG Project

a. Overview of Project

The Gorgon LNG Project (“Gorgon LNG”), located on Barrow Island off the Western Coast of Australia, is a large integrated LNG project that includes upstream development of remote gas fields, an LNG facility and a 44-mile gas pipeline. The project is situated on Australia’s largest gas resource, which could hold more than 40 Tcf of natural gas, and is expected to have a capacity of 16 MTPA.²¹⁴ The main sponsors of Gorgon LNG include Chevron (47% ownership), Exxon (25% ownership) and Royal Dutch Shell (25% ownership). Several Japanese utilities (combined 3% ownership) compose the remainder of the ownership structure.²¹⁵

Although originally estimated to cost \$37 billion in 2009, the project is now expected to cost \$54 billion, including gas field development costs. These cost overruns include higher work-related costs, weather and productivity issues, and, most significantly, the strengthening of the Australian dollar.²¹⁶ As a result of these cost overruns, the project is the largest single energy investment in Australia’s history.²¹⁷

The sponsors have executed long-term sale and purchase agreements (“SPAs”) with several Japanese, South Korean, Indian and Chinese companies for approximately 65% of the project’s output. As of November 2014, the project is 87% complete and has a targeted ISD of late 2015.²¹⁸

b. Map of Assets



Source: Chevron.

²¹⁴ Chevron company filings.

²¹⁵ “AUSTRALIA,” E, August 28, 2014.

²¹⁶ “Take-off for Australian LNG,” LNG 18, February 18, 2014.

²¹⁷ “Chevron’s Gorgon project 78% complete,” The Australian Business Review, March 2014.

²¹⁸ Chevron Press Release, October 31, 2014.

c. Overview of Financing

The Gorgon LNG Project relies upon Chevron, Exxon, Royal Dutch Shell and, to a lesser extent, Osaka Gas, Tokyo Gas and Chubu Electric Power to fund the project using their respective balance sheets. This is in contrast to the financing profile of many other LNG projects, which typically utilize non-recourse project financing.

The three Japanese utility project sponsors invested in Gorgon LNG's equity (specifically into Chevron's stake) in conjunction with their negotiations to purchase gas from Gorgon via 25-year SPAs. These sponsors have utilized loans from state-owned lending institutions to fund their respective stakes in the project.

Additionally, as a result of the cost overruns described above, the sponsors of the project have had to contribute additional funds to project development.

GORGON CAPITALIZATION TABLE²¹⁹

SECURITY	OWNERSHIP	PRICING	TERM
Equity			
Chevron	47.3%	NA	NA
Exxon	25.0%	NA	NA
Royal Dutch Shell	25.0%	NA	NA
Osaka Gas	1.3%	NA	NA
Tokyo Gas	1.0%	NA	NA
Chubu Electric Power	0.4%	NA	NA
Total Equity	100.0%	NA	NA

Source: Company filings, LoanConnector and news releases.

²¹⁹ Ownership amounts only refer to respective shares of costs and gas produced—individual parties can finance their respective capital requirements in accordance with individual capital budgeting targets.

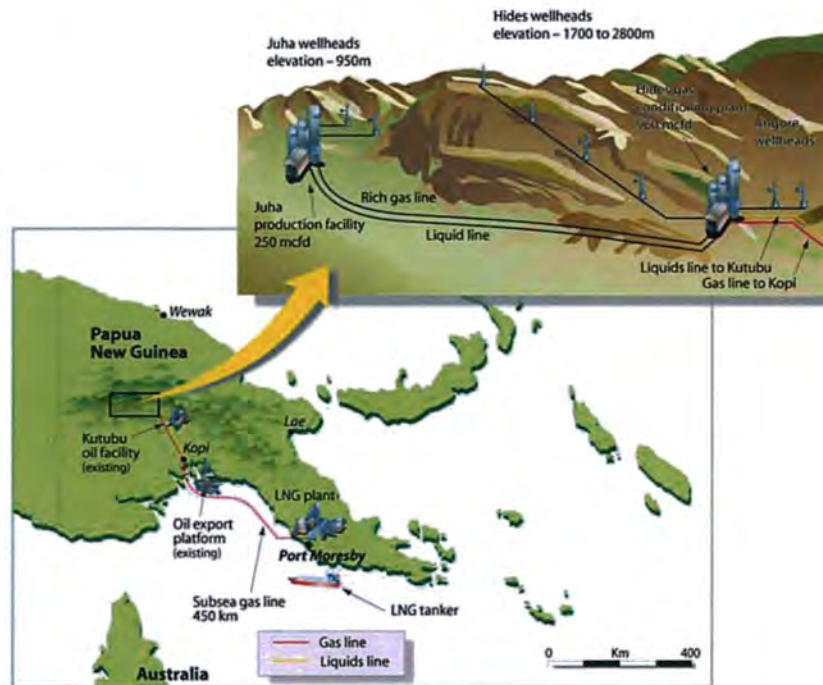
3. Papua New Guinea

a. Overview of Project

The PNG LNG Project, located in Papua New Guinea, is an integrated LNG development that includes upstream production at gas fields, a 435-mile above- and below-sea pipeline, a liquefaction terminal and export facility. The main sponsor of the project is Exxon, with support and investment provided by the Government of Papua New Guinea, Oil Search, Santos and other natural resource extraction companies.²²⁰

The project has a capacity of 7 MTPA and is expected to produce 9 Tcf of gas over its lifetime. The sponsors have contracted out the supply to a variety of buyers in Japan, China and Taiwan. The project is estimated to have cost \$19 billion and produced its first gas in May 2014.²²¹

b. Map of Assets



Source: Esso Highlands.

²²⁰ "PNG LNG: A World Class Financing Venture," ExxonMobil Gas & Power Marketing Company, April 2013 ("Exxon PNG Report").

²²¹ Exxon PNG Report.

c. Overview of Financing

The firms that provided equity to the project included Exxon (33% of equity), Oil Search (29% of equity), Santos (13% of equity), and Japan Papua New Guinea Petroleum and Nippon Oil Exploration (combined 5% of equity). Three Papua New Guinea-owned national firms also contributed a combined 20% of the equity.²²²

The PNG LNG Project utilized significant financing from public export credit agencies. Six export credit agencies, including the Export-Import Bank of the United States and the JBIC, have provided \$8.3 billion of loans to Exxon and the PNG LNG Project. In addition to investing equity and being the main operator of the project, Exxon also provided a \$3.8 billion loan from a subsidiary. To round out the financing, 17 commercial banks provided a total of \$3.5 billion.^{223,224}

PNG LNG CAPITALIZATION TABLE (\$ IN BILLIONS)²²⁵

SECURITY	AMOUNT	PRICING	TERM
Equity			
Exxon	\$1.2	NA	NA
Oil Search	1.0	NA	NA
National Petroleum Company of PNG	0.6	NA	NA
Santos	0.5	NA	NA
Nippon Oil	0.2	NA	NA
MRDC	0.1	NA	NA
Total Equity	\$3.5		
Debt			
2024 Term Loan (Project Finance)	\$3.5	L+325	15 years
2026 JBIC Export Credit (Project Finance)	1.8	NA	17 years
2026 Export-Import Bank of the United States Export Credit (Project Finance)	2.2	NA	17 years
2026 Export-Import Bank of China Export Credit (Project Finance)	1.3	NA	17 years
2026 Export Finance & Insurance Corp. (Project Finance)	0.4	NA	17 years
2026 Export Credit (Project Finance)	0.8	L+150	17 years
2026 Export Credit (Project Finance)	0.9	L+165	17 years
2026 Export Credit (Project Finance)	1.0	L+175	17 years
2026 Exxon Loan (Project Finance)	3.8	NA	17 years
Total Debt	\$15.5		

Source: Company filings, LoanConnector and news releases.

²²² Exxon PNG Report.

²²³ Exxon PNG Report.

²²⁴ "Exxon Secures \$1.5B For \$19B Papua New Guinea LNG Project," Law360, October 4, 2013.

²²⁵ Equity investments assume necessary equity contributions given current debt levels and projected cost of the PNG LNG Project. Also assumes that equity is invested in levels commensurate to project ownership.

4. Qatargas 2 LNG Project

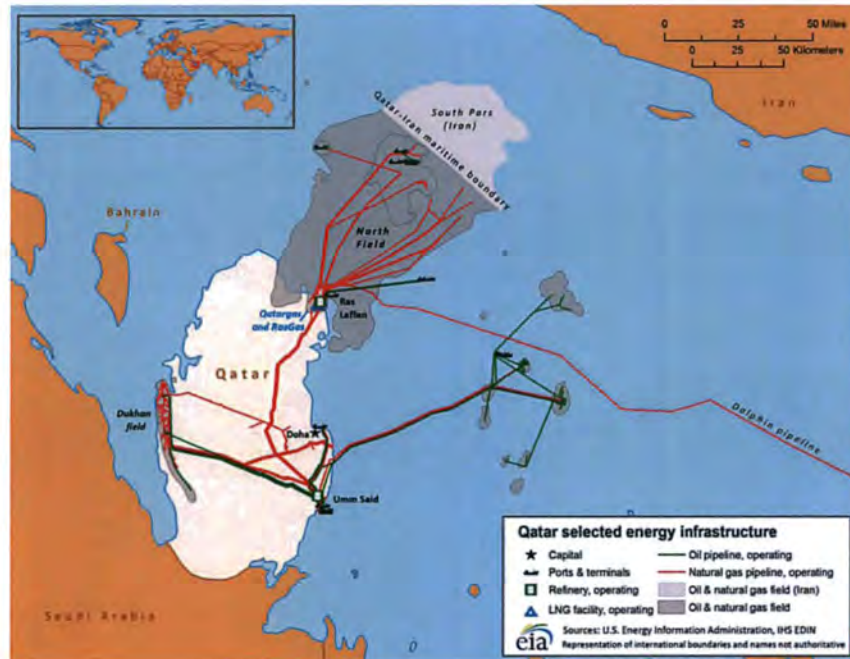
a. Overview of Project

The Qatargas 2 LNG Project, located in Qatar, is the world's first fully-integrated LNG development. The project included the development of 30 wellheads, several unmanned platforms, liquefaction and export facilities in Qatar, several tankers and an LNG receiving facility in Europe. The main sponsors of the project are Qatar Petroleum, a company owned by the government of Qatar, ExxonMobil and Total. The project cost was over \$12 billion and has a capacity of ~16 MTPA.^{226, 227}

Although the original goal of the project was to supply the U.K. with LNG, in the wake of the 2011 Fukushima crisis, much of the LNG is now projected to be shipped to Japan and other Asian countries. The sponsors negotiated SPAs for over 50% of production with the U.K.

The project is notable in that it was the first LNG project in which the entire value chain, from wellhead to terminal, was developed and financed by the same partners. Additionally, the project involved the development of the two largest liquefaction trains in the world.²²⁸

b. Map of Assets



Source: EIA.

²²⁶ "Milestones : Qatar Gas Project Pushes Bounds Of Project Finance," Global Finance, February 1, 2005.

²²⁷ Qatargas press release.

²²⁸ "White & Case Closes Largest Ever Energy Financing," White & Case, December 16, 2004 ("White & Case Report").

c. Overview of Financing

The sponsors targeted a 70/30 debt-to-equity ratio when financing the project.²²⁹

Qatar Petroleum owns the majority equity stake in both trains of the LNG plant (70% of train 1 and 65% of train 2), while the private sponsors, Exxon and Total, own the balance.²³⁰

The Qatargas 2 LNG Project also utilized significant debt financing. Altogether, \$7.6 billion was provided for the project, which, at the time, made it the single largest energy project financing in history. In total, 57 institutions provided debt financing for the project, including 36 commercial banks, an export credit agency, six Islamic banks and an Exxon lender on the upstream side, and 12 commercial banks and an Exxon lender on the receiving terminal side. Notably, the project utilized the largest amount of long-term Islamic project financing (\$530 million) in history.²³¹

QATARGAS 2 CAPITALIZATION TABLE (\$ IN BILLIONS)²³²

SECURITY	AMOUNT	PRICING	TERM
Equity			
Qatar Petroleum	\$3.0	NA	NA
Exxon	1.1	NA	NA
Total	0.4	NA	NA
Total Equity	\$4.4		
Debt			
2029 South Hook Term Loan (Project Finance)	\$1.1	NA	25 Years
2020 Islamic Financing (Project Finance)	0.5	NA	15 Years
2022 Export Credit (Project Finance)	0.8	NA	NA
2020 Term Loan	5.2	NA	NA
Total Debt	\$7.6		

Source: Company filings, LoanConnector and news releases.

²²⁹ "Issues Facing U.S. Shale Gas Exports To Japan," Pipeline & Gas Journal, December 2011.

²³⁰ Qatargas press release.

²³¹ White & Case Report.

²³² Equity investments assume necessary equity contributions given current debt levels and projected cost of the Qatargas 2 Project. Also assumes that equity is invested in levels commensurate to project ownership.

5. Ichthys LNG Project

a. Overview of Project

The Ichthys LNG Project, located off the coast of Western Australia, is an integrated LNG development. The project includes the development of a central processing facility, a floating production, storage and offtake vessel, a 556-mile pipeline and liquefaction facilities. The main sponsors of the project are INPEX (a Japanese oil company with a market capitalization of \$17 billion), Total, Tokyo Gas, Osaka Gas, Chubu Electric Power and Toho Gas. The project is expected to cost over \$34 billion and has a capacity of approximately 8.4 MTPA. The project has a targeted ISD of late 2016.²³³

The project is also the first in which a Japanese company has led a multinational LNG project as an operator.²³⁴

b. Map of Assets



Source: INPEX.

²³³ "Ichthys LNG Project," INPEX, 2014.

²³⁴ "INPEX Secures \$20 Bln in Loans for Ichthys LNG Project (Australia)," Offshore Energy Today, December 18, 2012.

c. Overview of Financing

The Ichthys LNG Project secured arrangements for \$20 billion of project financing, the largest amount ever arranged in international markets. The sponsors collected the funds from a variety of sources, including eight export credit agencies and 24 commercial banks.²³⁵

The project's equity owners are also providing debt financing. INPEX (66% of equity), Total (30% of equity) and the Japanese utilities (combined 4% of equity) are contributing \$4 billion in loans, in proportion to each company's equity stake.²³⁶

During the construction phase of the project, each of the sponsors will severally guarantee the repayment of the loans. Japan Oil, Gas and Metals National Corporation, a Japanese government owned agency, has agreed to guarantee \$2 billion of INPEX's commitment.²³⁷

ICHTHYS CAPITALIZATION TABLE (\$ IN BILLIONS)²³⁸

SECURITY	AMOUNT	PRICING	TERM
Equity			
INPEX	\$9.2	NA	NA
Total Equity	4.2	NA	NA
Tokyo Gas	0.2	NA	NA
Osaka Gas	0.2	NA	NA
Chubu Electric Power	0.1	NA	NA
Toho Gas	0.1	NA	NA
Total Equity	\$14.0		
Debt			
Export Credit Agency Direct Loans (Project Finance)	\$5.8	NA	NA
ECA insured/Guaranteed Commercial Loans	5.4	NA	NA
Commercial Loans	4.8	NA	NA
Sponsor Loans	4.0	NA	NA
Total Debt	\$20.0		

Source: Company filings, LoanConnector and news releases.

The project also uses novel structuring approaches to share development risk among the equity owners. The project's downstream facilities are owned by a special purpose vehicle that is the main borrower under the project financing. The upstream facilities are part of an unincorporated joint venture. Each sponsor owns an equal interest in both the upstream and downstream entities.

²³⁵ "Ichthys LNG Project Completes Project Financing Arrangements," INPEX, December 18, 2012 ("INPEX Report").

²³⁶ INPEX Report.

²³⁷ INPEX Report.

²³⁸ Equity investments assume necessary equity contributions given current debt levels and projected cost of the Ichthys LNG Project. Also assumes that equity is invested in levels commensurate to project ownership.

C. List of Selected Key Terms

Below is a list of key terms and definitions used throughout this Report. Where a term is defined or otherwise explained in further detail in this Report, the relevant section is indicated in parentheses.

- **AAPP:** Arctic Alaska Petroleum Province; location of the majority of Alaska's petroleum reserves (Section III.B.1.a)
- **AFUDC:** Allowance for Funds Used During Construction; a return-on-capital calculation for construction financing (Section IV.F)
- **AGDC:** Alaska Gasline Development Corporation (Section III.C and Section IV.C)
- **AGIA:** Alaska Gasline Inducement Act; 2007 State statute providing, among other things, for reimbursement of natural gas developers' expenses to promote development of a natural gas pipeline (Section III.D)
- **ANGDA:** Alaska Natural Gas Development Authority (Section III.C)
- **ANGTA:** Alaska Natural Gas Transportation Act; 1976 Federal statute promoting expedited development of a pipeline to deliver natural gas from Alaska to the Lower 48 (Section III.C)
- **ANWR:** Arctic National Wildlife Refuge; Federal area within Alaska's North Slope with significant undiscovered oil (Section III.B.1.a)
- **ARMB:** Alaska Retirement Management Board; entity controlling seven State retirement systems (Section VI and Section VI.B)
- **ASAP:** Alaska Stand Alone Pipeline; proposed 727-mile pipeline southward from the North Slope to an existing pipeline system in the Matanuska-Susitna Borough (Section III.C)
- **BBL:** Billion barrels (unit of *oil* volume)
- **Bcf:** Billion cubic feet (unit of *natural gas* volume)
- **CAPM:** Capital asset pricing model; framework for calculating cost of equity (Section VII)
- **CBRF:** Constitutional Budget Reserve Fund (Section V.A.1 and Section V.B.2)
- **Cook Inlet:** Area in Southcentral Alaska, location of substantial oil and gas reserves (Section III.B.2.b.ii)
- **DOE:** U.S. Department of Energy
- **EIA:** U.S. Energy Information Administration
- **EPC:** Engineering, Procurement and Construction; final phase of Project before operations, encompasses final engineering and preparation, and expected to cost approximately \$52.8 billion (midpoint) (Section IV.D and Section IV.G.1)
- **FEED:** Front-End Engineering and Design; final phase of Project before major construction, encompasses contract preparation and financing arrangements, and expected to cost approximately \$1.8 billion (midpoint) (Section IV.D and Section IV.G.1)
- **FERC:** Federal Energy Regulatory Commission
- **FID:** Final Investment Decision; last Project milestone before EPC phase (Section IV.D and Section IV.F – IV.G.1)

- **FTSA:** Firm Transportation and Services Agreement; agreement describing the tariff that the State of Alaska pays TransCanada under the Memorandum of Understanding (Section IV.C and IV.F)
- **Fuel Use Act:** Powerplant and Industrial Fuel Use Act; 1978 Federal statute restricting construction of new power plants and boilers (Section III.C – III.D)
- **FY:** the State of Alaska’s Fiscal Year starts on July 1 and ends on June 30 (e.g., Fiscal Year 2014 ended on June 30, 2014)
- **GeFONSI:** General Fund and Other Non-segregated Investments; includes the State’s general operating fund (Section V.B.2)
- **GTP:** the Project’s gas treatment plant (Section IV.B)
- **GW:** Gigawatt (unit of power equivalent to one billion watts)
- **Heads of Agreement:** agreement that establishes non-binding guiding principles and partner roles for the Project as well as important commercial and operating arrangements among each of the key Project parties (Section IV.A and Section IV.C)
- **IPO:** Initial public offering; method of issuing shares to public investors (Section VII.B.1)
- **ISD:** In-service date; date upon which a project becomes available for operations
- **JBIC:** Japan Bank for International Cooperation (Section VI.B)
- **KOGAS:** Korea Gas Corporation; state-owned South Korean utility (Section III.A.2)
- **LIBOR or L:** London Interbank Offered Rate; benchmark rate that banks charge each other for short-term loans (Section VII and Section XI.A.2)
- **LNG:** Liquefied natural gas
- **LNG Plant:** the Project’s liquefaction facility (Section IV.B)
- **Lower 48:** Contiguous U.S. states, consisting of 48 states and Washington, D.C.
- **Mcf:** Thousand cubic feet (unit of *natural gas* volume)
- **MMBD:** Millions of barrels per day (unit of *oil* volume)
- **MMBtu:** Million British thermal units (unit of energy)
- **MOU:** Memorandum of Understanding; agreement between the State and TransCanada (Section IV.F)
- **MTPA:** Metric tons per annum (unit of *LNG* volume)
- **North Slope:** Region in northern Alaska bound by the Brooks Range and Arctic Ocean (Section III.B.1 – III.B.2)
- **NPRA:** National Petroleum Reserve-Alaska; area within Alaska’s North Slope with significant undiscovered oil (Section III.B.1.a)
- **NPV:** Net present value; the present value of a series of future cash flows (Section IV.G.5)
- **OMB:** State of Alaska Office of Management and Budget; prepares and manages the State’s budget on behalf of the Governor (Section V.A.1)

- **PCE Endowment Fund:** Power Cost Equalization Endowment Fund; State fund created to provide affordable electricity for rural Alaska regions (Section V.B.2)
- **Pipeline:** the Project's natural gas pipeline (Section IV.B)
- **Point Thomson:** Area located in Alaska's North Slope; location of an existing oil and gas field (Section IV.B)
- **Pre-FEED:** Pre-Front End Engineering and Design; initial phase of Project, encompasses preliminary engineering and planning, and expected to cost approximately \$400 million (midpoint) (Section IV.D and Section IV.G.1)
- **Project:** the Alaska LNG Project
- **Prudhoe Bay:** Area located in Alaska's North Slope; location of an existing oil and gas field (Section III.B.2.b.i)
- **SB 138:** Senate Bill 138; 2014 State statute facilitating Alaska individuals' and entities' participation in ownership of a North Slope natural gas pipeline (Section I)
- **SBRF:** Statutory Budget Reserve Fund (Section V.A.1 and Section V.B.2)
- **SPA:** Sale and Purchase Agreement
- **Stranded Gas Act:** Alaska Stranded Gas Development Act; 1998 State statute enabling State negotiation of terms for oil producers dealing with stranded gas (Section III.C)
- **TAPS:** Trans-Alaska Pipeline System; 800-mile pipeline constructed in the 1970s to allow for the transportation of natural gas from Prudhoe Bay to Valdez (Section III.B.2.b.i)
- **Train:** Refers to an LNG plant's liquefaction and purification facility (Section XI.B)
- **Tcf:** Trillion cubic feet (unit of *natural gas* volume)
- **USGS:** U.S. Geological Survey; scientific agency of the U.S. Government
- **WACC:** Weighted average cost of capital; blended cost of financing that takes into consideration the amount of debt and equity in an entity's capital structure, and the respective costs (Section VII)
- **WTI:** West Texas Intermediate; a type of crude oil, the price of which is often used as a benchmark for oil prices (Section III.A.1)

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October 23, 2015

The Honorable Mike Chenault
Speaker of the House
Alaska State Legislature
State Capitol, Room 208
Juneau, AK 99801-1182

Dear Speaker Chenault:

Under the authority of Article II, Section 9, and Article III, Section 18, of the Alaska Constitution, I am transmitting a bill for supplemental appropriations for the fiscal year 2016. The bill will move us toward monetization of our vast natural gas resources by engaging the State fully in the process as an equal participant in our future development.

First, the bill requests an appropriation to the Alaska liquefied natural gas (AKLNG) project fund in order to acquire the interests of TransCanada. While TransCanada has been a valuable ally, it is time for the State to step in and participate as a full partner in the development of a gas pipeline and liquefaction facilities.

In the last several days, the producers have reviewed an overall Preliminary Front-End Engineering and Design (Pre-FEED) phase increase from \$511,000,000 to \$693,000,000 that will impact costs in calendar year 2016. The State's 25 percent share of this Pre-FEED increase is included in the supplemental request.

Additionally, the bill requests necessary appropriations to the Departments of Natural Resources, Law, and Revenue related to the State's continued and vital participation in the AKLNG project. Further appropriations recognize the need for Alaska Gasline Development Corporation to have statutory program receipt authority to be reimbursed from producers for specific work on the AKLNG project.

Finally, the Legislature recognized earlier this year when it passed HB 2001 that there may be a need for supplemental appropriations for fiscal year 2016, and authorized the withdrawal from the budget reserve fund for fiscal year 2016 to include an amount, not to exceed \$500,000,000, for future fiscal year 2016 appropriations. Accordingly, this bill provides that if there are insufficient general funds available for appropriation, Section 12(c), Chapter No. 1, SSSLA 2015, will apply to the supplemental appropriations provided for in this bill.

The Honorable Mike Chenault
Transmittal AKLNG Appropriations
October 23, 2015
Page 2

Thank you for your consideration of this bill.

Sincerely,

A handwritten signature in black ink that reads "Bill Walker". The signature is written in a cursive, flowing style.

Bill Walker
Governor

Enclosure

BILL WALKER
Governor



P.O. Box 110001
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STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

Questions and Answers: House Finance – 1:00 PM – October, 24 2015

Representative Wilson:

How would using the permanent fund account affect our credit rating vs using the CBR? If our credit rating is lowered, it will affect not only this project but all other projects the state is borrowing for correct? Why or why not would the State of Alaska want to invest in this?

Department of Revenue Response:

Using the Alaska Permanent Fund (APF) will have less of an impact on the states ratings than using the CBRF. The CBRF is available for all state expenditures while the APF is limited to investment opportunities. The CBRF will need to be repaid while the APF can be viewed as investment.

Representative Neuman:

Asked for copies of all reports that have been given out to the administration. Would also like base-line of what financial decisions are based on.

Department of Revenue Response:

- Lazard, FirstSouthwest and Greengate LLC have provided the following reports.
- The Interim Lazard Report, February 2015

<http://dor.alaska.gov/Portals/5/AKLNG-PROJECT-LAZARD-INTERIM-REPORT-2015.pdf>

FirstSouthwest analysis on the state's debt capacity as described below:

The most recent analysis of the State's debt capacity is attached.

The attached analysis is as of June 3, 2015. The analysis shows how much the State could potentially borrow for the project with general obligation bonds, taking into account ratios for debt service as a % of unrestricted general fund revenues and interest rates associated with specific credit ratings using both tax-exempt and taxable rates.

First Southwest believes that a State borrowing could be feasible. There are several ways that the State could access the debt capital markets. One method is to issue general obligation bonds.

General obligation bonds would require voter approval. A second method would be to issue appropriation backed bonds. Appropriation bonds would require annual appropriations from the State Legislature for the payment of debt service. Another alternative would be to have AGDC issue the bonds. This would also require an annual appropriation for debt service from the Legislature. Yet another alternative is to issue bonds for projects that are currently funded on a pay-as-you-go basis and use those freed up pay-go funds for the project which otherwise would not have qualified for lower cost tax-exempt bond funding. The financing costs under this option could be on a tax-exempt basis.

FirstSouthwest believes that any of the above alternatives would result in lower financing costs to the State. The basis behind that assumption is twofold. First, under the TransCanada Precedent Agreement, TransCanada is entitled to a "Carrying Cost Calculation" on its capital invested during the Pre-FEED JVA stage at a rate of 7.1%. This is materially higher than anticipated financing costs on a State borrowing. Current municipal market rates suggest an interest cost to the State of approximately 3.06% for 20 year AAA rated tax-exempt general obligation bonds and 4.36% for AAA rated taxable general obligation bonds, while interest costs for certificates of participation (appropriation backed debt) rated a notch below the State's general obligation rating are currently at 3.41% for tax-exempt bonds and 4.76% for taxable bonds. Secondly, the Precedent Agreement provides for an agreed weighted cost of capital for TransCanada of 6.15% (per B&V Report) for TransCanada's FEED and FID capital investment (with the Pre-FEED JVA capital and 7.1% Carrying Cost Calculation included as part of the capital investment against which the weighted cost of capital is applied). Again, we note this is higher than anticipated State financing costs as described above. Second, we believe that any debt issued by the State will carry a higher credit rating than the ratings on TransCanada debt that might be issued backed by the revenues from the State's Firm Transportation Services Agreement with TransCanada. TransCanada's current long term debt credit ratings (see attachment).

Representative Neuman:

Is this standard boiler plate contracts we have with TC or are we forging new ground here? What I am trying to get to is to see how much risk we are funding, and you said these circumstances are unique, I want to look at that further. Is the risk proportionate for all the parties or is the state taking on more risk than the other? Send us what are the risks and how and why they are risks, and what we can do to manage those risks?

Department of Revenue Response:

Risks Faced Generally by LNG Project Equity Participants:

- Technical Feasibility: determined during Pre-FEED/FEED; can the Project be technically constructed (permitting, route, geology, environmental, technology). Equity participants assume the risk of losing their investment in Pre-FEED/FEED costs if Project deemed not technically feasible.

- **Financial Feasibility:** determined during Pre-FEED/FEED; if built, can the Project be completed and operated at a cost that delivers a profit on gas sales with a return sufficient to justify constructing the Project. Equity participants assume the risk of losing their investment in Pre-FEED/FEED costs if Project deemed technically feasible but not financially feasible.
- **Funding Feasibility:** determined during Pre-FEED/FEED; if technically feasible and financially feasible, will the financial markets have sufficient liquidity to fund the Project construction costs at an acceptable level and cost of debt/equity. Equity participants assume the risk of losing their investment in Pre-FEED/FEED costs if Project deemed technically feasible, financially feasible, but not fundable under then current financial market conditions.
- **Construction Completion:** determined after FID; can the Project be completed and placed into service. Equity participants assume the risk of losing their Pre-FEED/FEED/ and Construction investment if the Project construction cannot be completed and placed in operation.
- **Cost Overruns/Project Delays:** determined during FID; if the Project experiences cost overruns and project delays, do those cost overruns and project delays undermine the financial feasibility of the Project and will funding be available to meet the cost overruns. Equity participants assume the risk of negative netback from the Project or loss of investment in worst case scenario.

Risks Allocated Among the AKLNG Participants

- **Among Producer Parties and State:** under the current commercial structure being negotiated, the categories of risk outlined above are allocated proportionately to each party based on its share of gas projected to flow into the Project from PBU and PTU, which is mirrored in the percentage ownership of and allocated of construction and operating costs in the Project.
- **State Disproportionate Risk:** although the Pre-FEED, FEED, and post-FID construction and operating cost risks are allocated proportionately among the Producers and the State, the State has a disproportionate risk as an indirect gas owner with no control of the upstream gas fields (vs. the Producers direct control), and as sole source gas market participant with no previous market experience and buyer relationships (vs. the Producers with multiple worldwide gas source availability, extensive market experience and multiple relationships with buyers).

Risks Allocated Between the State and TransCanada

- **Technical Feasibility:** under the terms of the PA and anticipated terms of an FTSA, all technical feasibility risk is born by the State with none born by TransCanada. If the Project does not proceed to FID, the State reimburses all of TransCanada Project costs plus interest at a negotiated rate (7.1% for Pre-FEED, as adjusted for 30 year Treasury Bill fluctuations through FEED).
- **Financial Feasibility:** under the terms of the PA and anticipated terms of an FTSA, all financial feasibility risk is born by the State with none born by TransCanada. If the Project does not proceed to FID, the State reimburses all of TransCanada Project costs plus interest at a negotiated rate (7.1% for Pre-FEED, as adjusted for 30 year Treasury Bill fluctuations through FEED).
- **Funding Feasibility:** under the terms of the PA and anticipated terms of an FTSA, all funding feasibility risk is born by the State with none born by TransCanada. If the Project does not proceed to FID, the State reimburses all of TransCanada Project costs plus interest at a negotiated rate (7.1% for Pre-FEED, as adjusted for 30 year Treasury Bill fluctuations through FEED). If the Project does proceed to FID, but TransCanada does not identify debt and equity funding for its share of the construction of the Project at a cost and on terms acceptable to TransCanada in its sole

discretion, TransCanada can unilaterally exit the Project and the State reimburses all of TransCanada Project costs plus interest at a negotiated rate (7.1% for Pre-FEED, as adjusted for 30 year Treasury Bill fluctuations through FEED).

- **Construction Completion:** under the terms of the PA and anticipated terms of an FTSA, all Construction Completion risk is born by the State with none born by TransCanada. If the Project construction is not completed and the Project does not go into service, the State reimburses all of TransCanada Project costs plus interest at a negotiated rate (7.1% for Pre-FEED, as adjusted for 30 year Treasury Bill fluctuations through construction).
- **Cost Overruns/Project Delays:** under the terms of the PA and anticipated terms of an FTSA, all Cost Overruns and Project Delays risk is born by the State with none born by TransCanada. Cost Overruns are included in TransCanada's tariff capital cost calculation to be recovered from the State through an increased tariff payment. Project delays are solely born by the State, as TransCanada has no gas sales/buyer default risks, and TransCanada interest continues to accrue and be capitalized into the tariff capital cost calculation to be recovered from the State through an increased tariff payment.
- **Appropriation Risk:** TransCanada assumes the risk that the Legislature will not appropriate funds necessary to reimburse TransCanada if TransCanada exits the Project or the Project is terminated or will not appropriate funds necessary to pay the TransCanada tariff after the Project is operational. To hedge this risk, TransCanada has included a requirement in the PA and anticipated terms of the FTSA that the State pledge the full faith and credit of the State to make such payments or dedicate a separate State fund to secure such payment (which would require a voter referendum or Constitutional Amendment). TransCanada has also included a requirement that the State maintain an investment grade credit ratings at all times during the Project, absent which TransCanada can terminate its participation in the Project and accelerate all reimbursement obligations of the State.

Representative Gara:

I would like to quantify the value. If we buy out TC and we finance it at a favorable rate, who can quantify if that is better than leaving them in the project and paying their tariff?

Department of Natural Resources Response:

Slides 19-21 of the "TransCanada's AKLNG Participation" presentation given by Deepa Poduval on Monday, October 27, 2015, in House Finance walks through a comparison of the value associated with retaining TransCanada vs. terminating the relationship.

The State could potentially achieve up to ~\$400 million incremental annual cash flows, based on the State's expected lower cost of capital.

Representative Gara:

Can you provide scenarios on if we leave TC in through feed and pre feed or if we buy them out now, how much would we save/spend in each scenario?

Department of Natural Resources Response:

The table below shows the total cost to the State of leaving TC in for pre-FEED until Dec 2015 and a scenario leaving TC for FEED until December 2018. In the scenario where the State terminates

the TC relationship in Dec 2015, the State would need to repay TC approximately \$70MM. In the scenario where the State terminates the TC relationship in Dec 2018 after FEED, the State would need to repay TC approximately \$490MM. The total repayment to TC would include WP&B costs for AKLNG, TC's internal costs as well as 7.1% interest as shown below:

	Nominal \$Millions	
	Dec 2015	Dec 2018 (Current Estimate for end of FEED)
WP&B Costs	\$51	\$400
TC Internal Management Fee	\$16	\$35
Interests Costs	\$3	\$55
Total	\$70	\$490

* All values are approximate and are based on estimated Pre-FEED and FEED costs and schedule.

Representative Gara:

In trying to determine the difference between the two (if the State buys out TC and fails after FEED or TC remains after FEED), would we calculate that the 7% payment would be on estimate of roughly \$820 million dollars over 4 years?

Department of Natural Resources Response:

Of the total \$820 million that is estimated to the total share of the State's cost going forward to complete Pre-FEED and FEED without TC, approximately \$15MM for Pre-FEED and \$365MM for FEED are associated with AGDC's investment in the AKLNG LNG plant component which would have been incurred directly by the State with or without TC. In addition to TC's estimated costs to date for Pre-FEED (of approximately \$67MM), the 7% interest for TC would apply to approximately \$60MM of remaining AKLNG midstream costs to complete Pre-FEED and \$310MM of AKLNG midstream costs for FEED. As indicated in the response to Question 5, the total interest cost to TC if the agreement is terminated in Dec 2015 during Pre-FEED would be approximately \$3MM and the interest expense to TC if the relationship is terminated assuming a Dec 2018 end of FEED would be approximately \$55MM.

Representative Edgmon:

Is the permeant fund on anyone's sights here?

Department of Revenue Response:

The Permanent Fund is being considered as part of a financing package and a full analysis will be included in the final Lazard Report to be presented to the legislature when the Commissioner of the

Department of Natural Resource submits the first contract or agreement.

Representative Gara:

As a shipper of gas, if we send less gas than expected will we still owe on the amount that was supposed to be shipped?

Department of Natural Resources Response:

Yes. The SOA will be obligated to pay for transportation whether we ship the required volumes or not. Secondly, the long term gas contracts with the customers will require us to deliver the full volume of contracted gas. These are the reasons: the upstream supply and delivery agreements are so critical; billions of dollars are at stake. The SOA as a non-producer must use commercial agreements to ensure its gas is available.

Representative Saddler:

SB 138 sets up a clear process and in the AKLNG project over the last year we haven't firmed up the transportation services agreement and other milestones. Does the failure to hit these milestones affect our credit rating? Does AKLNG appear less valuable?

Department of Revenue answered in hearing, written response:

AKLNG is a complex process. The rating agencies have noted that the State is proceeding upon a difficult and complicated journey. It is unrealistic to expect that there will not be delays or challenges. To date, the State has not incurred significant obligations that required access the capital markets. The rating agencies will take a more intensive look when the State will issue debt.

Representative Neuman:

**How do we see the state measuring these contracts that go for 25-30 years?
How do we see the credit agencies analyzing that knowing what is coming and our plan looks at a 30 year plan on financing this. How do you analyze the PA and the buyers of gas credit ratings? How much would the credit rates scrutinize the purchasers of gas? What are the possible alternatives the state could face? What are the possible future implications? What about the market in the future? What are long term projects in the Asian market looking like?**

Department of Revenue answered in hearing, written response:

Using the purchasers of gas to help finance the project is one option that the State will explore. The purchase contracts have not been negotiated as of yet, and this process could take several years. When and if such contracts are executed, the rating agencies will review those contracts to see if they are creditworthy. There are a number of factors that will go into the rating agencies' analysis, but it is too early in the process to comment upon the potential purchaser at this time.

Representative Saddler:

When looking at all scenarios, the governor has mentioned going to Asian buyers. Can you describe the implications if we turn to buyers who look at both sides of our equity sheet as owners and buyer?

Department of Revenue answered in hearing, written response:

LNG buyers will be an important component of the Project's commercial structure and ultimate economic viability. The implications of having one or more LNG buyers potentially also participate as co-owners of the Project could help align incentives with key customers and, potentially, enable more favorable commercial terms than might otherwise be available. It is important to note that, given the early stage of the Project, it is premature to know whether or not pursuing LNG buyers as co-owners of the Project would be advantageous for the State, and the ultimate implications in this regard will largely depend on the specific terms of the agreements that would be negotiated in the future.

BILL WALKER
Governor



P.O. Box 110001
Juneau, AK 99811-0001
(907) 465-3500

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

Questions and Answers: House Finance - 3 pm - October, 25 2015

Representative Neuman:

What are the problems with TC? What are the issues? Are they good or bad?

Department of Natural Resources(DNR) Response:

As Deputy Commissioner mentioned during testimony, some of the issues the State has experienced with TransCanada center around some of the governance issues and access to information. However, the State would like to emphasize that TransCanada is a world-class pipeline company and the State has not found any fault with the technical expertise provided to the State.

If TC remains in the Alaska LNG Project, they could demand independent control over the midstream segment of the project going forward, which will likely lead to a misalignment of expectations and wants because TC answers to its shareholders versus the citizens of Alaska.

Without TC, access to information will still require AGDC to be the conduit between the Project and the State, but now AGDC will have access to all aspects of the project (including midstream). Furthermore, voting will be through AGDC but AGDC does answer to the State and its citizens in many ways and will therefore not be "independent" in the same way as TC would have been.

Representative Thompson:

Who is the state gas team? What role do they play? How do they interact with AGDC?

DNR Response:

The State Gas Team (SGT) consists of personnel from the Department of Natural Resources (DNR), and in particular personnel from the North Slope Gas Commercialization (NSG) component, the Department of Revenue (DOR) and Department of Law (DOL) and the Office of the Governor. The team provides the administration with in-house capacity for consistent support and well-informed advice throughout the negotiation and crafting of critical commercial agreements related to the Alaska LNG Project. The SGT also consists of subject matter experts within these agencies and external consultants.

The AKLNG state gas team is primarily responsible for:

- Negotiating critical commercial agreements for the Alaska LNG Project with the Producer parties (ExxonMobil, BP, and ConocoPhillips);
- Developing a plan to market and dispose of the State's share of project gas for in-state use and LNG exports;
- Evaluating, and if it's in the best interest of the State, modify existing lease structures to accommodate the State taking tax-as-gas and royalty in-kind;
- Negotiating Property Tax for the Payment in Lieu of Taxes (PILT) and Impact Payments during construction;
- Assuring the project allows for adequate expansion for new discovery and alternative gas supplies; and
- Assuring the pipeline is adequately designed to provide supply to meet in-state gas demand (demand is determined by the Alaska Gasline Development Corporation).

The State Gas Team coordinates with AGDC on a number of different levels:

- AGDC serves as the SGT's conduit for accessing AKLNG Project technical information developed by the Houston-based AKLNG Project Team
- SGT and AGDC conduct bi-weekly meetings to coordinate on aspects of providing AKLNG gas for in-state use
- SGT provides AGDC with technical information on Upstream gas supply to support the engineering analysis of the project's technical design basis

Representative Neuman:

Is there anything that lines out who the players are?

DNR Response:

Organization Chart provided on 10/26/15 (attached).

Representative Guttenberg:

Costs that incurred as project expenses, are they passed on to TC or does the state cover them? What is the timeline if we terminate before TC terminates? Or if they terminate first?

DNR Response:

Refer to "TC Right to Terminate and Effect of Termination" distributed on 10/26/15 (attached).

Representative Neuman:

We need a chart that lines this out. If the state terminates vs if TC terminates

DNR Response:

Refer to "TC Right to Terminate and Effect of Termination" distributed on 10/26/15 (attached).

Representative Neuman:

I would like to know where we are in negotiations and I would like it in writing.

DNR Response:

Active negotiations among the State, AGDC and the Producers (with the parties varying depending on the nature of the agreement) are currently underway on the following commercial agreements and issues. As these negotiations include proprietary and confidential terms and conditions, additional details on these agreements and issues will be provided as negotiations are completed.

- Fiscal agreement
- Governance agreement
- Gas supply/balancing agreement
- Expansion and Access terms
- Withdrawal agreement
- Gas Sales by Withdrawing Parties agreement
- Byproduct Handling Agreement/Terms (including treatment of CO₂)
- Lease Modifications/Conversions
- Joint Venture Marketing Agreement(s) and/or Producer offers to purchase RIK gas per SB 138
- Aspects of the System Use Agreement (including Capacity Release provisions for imbalance management)
- Agreement on pro rata obligation to provide for utility Domestic Gas needs on reasonable terms (e.g., no requirement for AGDC to make long-term take-or-pay commitments)

A number of commercial agreements necessary to inform the RIK/RIV decision cannot be finalized until the details of a gas balancing agreement have been resolved because there are key inter-dependencies. These include upstream and information sharing agreements, and aspects of governance and system use agreements, especially as they relate to capacity entitlement and capacity release.

Representative Gattis:

Will it take longer than 120 days to buy TC out?

DNR Response:

We do not anticipate that it will take longer than 120 days to buy out TransCanada. Furthermore, it is not the intent of DNR or TC to drag out the closing of the buyout. Both DNR and TC are willing to amend existing contractual arrangements to reasonably meet the needs of the parties.

Representative Gattis:

Are we currently auditing or will we have to back track?

DNR Response:

DOR has not begun auditing any of the expenditures but the process for audits of TC's development costs are contained in the Precedent Agreement Article 4.3(c). Article 4.3 of the Precedent Agreement outlines the requirements necessary in case of a termination. DOR is in the process of procuring services for that audit and working with TransCanada. From an accounting perspective, until we give a notice of termination or receive a termination notice, an audit would not begin. Once Notice is given, the State has 30 days to perform the audit process in accordance with the provisions established in the current PA

DOR Responses to additional auditing questions:

Is there time built into the PA's billing/payment process for the audit of numbers and does it trigger any delays to payment timing requirements?

Yes. The current PA sets out the auditing process and payment timing requirements. The State has not been provided the actual termination amount or any supporting documentation. This information will be provided when the Notice of Termination is submitted.

If we need to challenge TC's numbers, what is the process and, again, how does it affect payment timing?

Under the PA, TC's costs are challenged as part of the audit process. Any disputed amounts by the State are placed into an escrow account set up by the parties. Disputed amounts are determined through executive level dispute resolution process and paid within 30 days. Unresolved issues are tried in Alaska courts.

Amendment No. 01

WHEREAS, The Alaska Gasline Development Corporation ("AGDC") and Rigdon H. Boykin (the "Contractor") have entered into a Master Services Agreement (the "Agreement") effective May 28, 2015, with a term that extended until September 1, 2015;

WHEREAS, AGDC and the Contractor hereby agree to extend the term of the Agreement in accordance with the terms of the Agreement and the terms provided herein;

Therefore, AGDC and the Contractor agree that paragraph 32 of the Agreement is amended to provide that the Agreement shall expire on September 30, 2015.

Except as specifically amended herein, all other terms and conditions of the Agreement remain unchanged and in full force and effect.

IN WITNESS WHEREOF, the parties have executed this amendment on the dates set out below. This amendment takes effect on the date of its execution by AGDC.

Agreed to and accepted by the CONTRACTOR

By: Rigdon H Boykin
(Authorized signature)
Rigdon H Boykin
(Printed name/title)

8-20-15
Date

Agreed to and accepted by the ALASKA GASLINE DEVELOPMENT CORPORATION

By: Daniel R Fauske
(Authorized signature)
DANIEL R FAUSKE President
(Printed name/title)

8-20-15
Date

Approved as to form
[Signature]
LEGAL

Amendment No. 02

WHEREAS, The Alaska Gasline Development Corporation ("AGDC") and Rigdon H. Boykin (the "Contractor") have entered into a Master Services Agreement (the "Agreement") effective May 28, 2015, with a term that extended until September 30, 2015;

WHEREAS, AGDC and the Contractor hereby agree to extend the term of the Agreement in accordance with the terms of the Agreement and the terms provided herein;

Therefore, AGDC and the Contractor agree that

1. Paragraph 32 of the Agreement is amended to provide that the Agreement shall expire on December 31, 2015.
2. Paragraph 1 of Exhibit E of the Agreement is amended to provide that in addition to the Contractor's monthly fee, the Contractor will be reimbursed for actual expenses, including per diem, up to \$10,000.00 per month. In no event will AGDC be obligated to pay, or liable for, an amount greater than \$850,000.00.

Except as specifically amended herein, all other terms and conditions of the Agreement remain unchanged and in full force and effect.

IN WITNESS WHEREOF, the parties have executed this amendment on the dates set out below. This amendment takes effect on the date of its execution by AGDC.

Agreed to and accepted by the CONTRACTOR

By: *Rigdon H Boykin*
(Authorized signature)

9/27/15
Date

Rigdon H Boykin
(Printed name/title)

Agreed to and accepted by the ALASKA GASLINE DEVELOPMENT CORPORATION

By: *Bruce Tangeman*
(Authorized signature)

9/27/15
Date

Bruce Tangeman
(Printed name/title)

Approved as in form
[Signature]
LEGAL

**AGDC Master Services Agreement
Contract Number: 15-078**

This Master Services Agreement, including all task orders (as defined in Exhibit B hereto, the "Task Orders"), if any, issued hereunder and including the exhibits attached hereto, (collectively, the "Agreement") is made between Rigdon H. Boykin (the "Contractor") and the Alaska Gasline Development Corporation ("AGDC").

For good and valuable consideration in hand paid, receipt of which is hereby acknowledged, the Contractor and AGDC agree as follows:

1. INCORPORATION BY REFERENCE. The following documents (each, an "Exhibit" and, collectively, the "Exhibits") are incorporated by reference into this Agreement.

- a. Exhibit A: RESERVED
- b. Exhibit B: Scope of work
- c. Exhibit C: RESERVED
- d. Exhibit D: RESERVED
- e. Exhibit E: Invoicing, and Payment
- f. Exhibit F: RESERVED
- g. Exhibit G: Subcontractor Rider

2. CONTRACTOR'S DUTIES. This Agreement is for services specified in Exhibit B. The Contractor shall diligently perform for AGDC all of its duties under this Agreement in accordance with Exhibit B or other instructions by AGDC. All work performed by the Contractor is subject to inspection, evaluation, and approval by AGDC. AGDC may employ all reasonable means to ensure that the work progresses and is performed in compliance with this Agreement.

The Contractor shall have no liability for defects in the services attributable to the Contractor's reliance upon or use of data, design criteria, drawings, specifications, or other information furnished by AGDC or by third parties retained by AGDC; provided, however, that the Contractor shall at all times and in all circumstances use judgment reasonable to the Contractor's level of expertise and knowledge in conducting work under this Agreement to discover and alert AGDC to any such defects. The Contractor, unless otherwise provided in any Exhibit to this agreement shall not be responsible for the verification of any documents or other information provided by AGDC and relied upon by the Contractor in performing the services.

In performing the services, the Contractor may be required to make certain assumptions or forecasts of conditions, events, or circumstances that may occur in the future. The Contractor will take reasonable efforts to assure that assumptions and forecasts made are reasonable and the basis upon which they are made follow generally accepted practices for such assumptions or projections under similar circumstances.

3. **SUBCONTRACTORS.** Subject to compliance with the provisions of this paragraph, the Contractor may engage subcontractors to perform services required by this Agreement or otherwise to support the Contractor's performance of services under this Agreement. The Contractor shall notify AGDC in writing of the name of each subcontractor to be engaged by the Contractor under this paragraph and the work anticipated to be performed by the subcontractor. A subcontractor may not begin work under this paragraph before (a) the Contractor and subcontractor have executed a Subcontractor Rider in the form set forth in Exhibit G; (b) the Contractor has delivered to AGDC the completed, signed Subcontractor Rider; and (c) the Contractor and subcontractor have entered into a contract or other agreement and attached the executed Subcontractor Rider to such contract or other agreement. All compensation and reimbursement payments to a subcontractor are the responsibility of the Contractor, and AGDC is not responsible for, and will not make, payments owed by the Contractor to the subcontractor.

4. **TRAVEL.** AGDC will reimburse the Contractor for travel expenses incurred or paid in conducting work under this Agreement.

5. **NO ADDITIONAL WORK OR MATERIALS.** AGDC is responsible only for payment of work and provision of materials as provided in this Agreement.

6. N/A

7. N/A

8. **COMPENSATION.** AGDC will pay the Contractor as provided in Exhibit E. AGDC is not responsible for payment for, and will not pay for, work performed or materials provided before the date on which both AGDC and the Contractor have signed this Agreement. All costs associated with the Agreement must be stated in U.S. currency.

9. **REIMBURSEMENT.** Any costs or expenses the Contractor incurs performing the Contractor's duties under this Agreement will be reimbursed by AGDC except as provided in this Agreement.

10. **TERMINATION BY CONTRACTOR.** The Contractor may terminate this Agreement at any time but not sooner than sixty days after the Contractor has given written notice to AGDC.

11. **TERMINATION BY AGDC.** AGDC, by written notice to the Contractor given at any time on or before the date of termination, may terminate this Agreement at any time.

Regardless of whether AGDC has notified the Contractor of the termination of this Agreement under this paragraph, AGDC may take any action that, in its discretion, is reasonable to protect itself from the Contractor's breach of this Agreement.

Failure of AGDC to exercise its right to terminate this Agreement for the Contractor's breach does not waive that right or any other right under this Agreement.

AGDC is liable only for payment in accordance with the compensation and other provisions of this Agreement for services rendered before the effective date of any termination of this Agreement.

12. **TERMINATION NOT A RELEASE.** Termination of this Agreement by AGDC as permitted by this Agreement does not release the Contractor from any obligations or liability under the Agreement unless AGDC expressly releases the Contractor in writing. Upon termination of the Agreement by AGDC, the Contractor must assist in an orderly transfer of the Contractor's entire work product, including all work product of any subcontractor or vendor of the Contractor, related to this Agreement to the offices of AGDC or to any successor or custodian designated by AGDC in writing. Notwithstanding the termination

of this Agreement, the Contractor shall preserve and protect all such files, notes, draft reports, and other work product, including maintaining the confidentiality of the same, and the Contractor's duty to preserve and protect all such material shall survive the termination of this Agreement until such time as the Contractor shall have delivered all such material to AGDC and AGDC shall have acknowledged receipt of same in writing to the Contractor.

13. INDEMNIFICATION. The Contractor shall indemnify, save harmless and defend AGDC and the State, its officers, agents, and employees from all liability, including costs and expenses, for all actions or claims resulting from injuries or damages sustained by any person or property arising directly or indirectly as a result of any error, omission, or negligent act of the Contractor, its subcontractors, or anyone directly or indirectly employed by the Contractor in the performance of this Agreement.

All actions or claims, including costs and expenses, resulting from injuries or damage sustained by any person or property arising directly or indirectly from the Contractor's performance under this Agreement which are caused by the joint negligence of AGDC and the Contractor shall be apportioned on a comparative-fault basis. Any such joint negligence on the part of AGDC must be a direct result of active involvement by AGDC.

"Contractor" and "AGDC" as used within this article, include the employees, agents and other contractors who are directly responsible, respectively, to each.

14. NO ASSIGNMENT OR DELEGATION. This Agreement is a personal services agreement, and the Contractor may not assign or delegate this Agreement, or any part of it, or any right to any compensation or reimbursement paid under it, except with the express written consent of AGDC, which AGDC will not unreasonably withhold; provided, however, that the Contractor may, subject to the provisions of paragraph 3 above, subcontract portions of the services to approved subcontractors.

15. NOTICE. Any notice given to AGDC or to the Contractor under this Agreement must be in writing and must be sent by registered mail or certified mail, return receipt requested, or by email to the address described in the "Notice" section of Exhibit E.

The Contractor and AGDC will promptly notify each other of any changes in their respective addresses (including email addresses).

16. OWNERSHIP, PRESERVATION, RETENTION, AND DELIVERY OF RECORDS. All records related to work performed by the Contractor for AGDC under this Agreement, including but not limited to documents, reports, recommendations, analysis, work produced in any form including intellectual property, computerized data files, and other media or papers of whatever kind or description and all information and materials made available to Contractor by AGDC (each, a "Record" and, collectively, the "Records"), regardless of whether the Records are developed or originated by the Contractor or by a subcontractor or vendor of the Contractor or by AGDC, are the sole property of AGDC.

Nothing contained in this Section shall be construed as limiting or depriving the Contractor of its rights to use its basic knowledge and skills to design or carry out other projects or work for itself or others, whether or not such other projects or work are similar to the work to be performed pursuant to this Agreement.

AGDC shall not acquire any rights to any of the Contractor's, its subcontractors', or its vendors' proprietary computer software that may be used in connection with the services provided under this Agreement.

The Contractor, upon AGDC's written request, shall deliver all Records to AGDC or as AGDC otherwise dictates in writing. The Contractor may not condition the delivery of Records in any manner whatsoever. The Contractor must reproduce, at no cost to AGDC, any Records that the Contractor has retained on microfilm or otherwise condensed. The Contractor acknowledges that time is of the essence with respect to any request for Records described in this paragraph. The Contractor agrees that, immediately upon receipt of any such request, the Contractor shall take reasonable steps necessary to provide for delivery of the requested Records at the earliest possible time, which, unless otherwise agreed to by AGDC in writing, shall be no later than 30 days after receipt of the request. In addition to all other remedies available to AGDC for breach of this provision, AGDC may withhold payment of any amount owed to the Contractor until such time as the Contractor delivers the requested Records to the satisfaction of AGDC.

Unless all Records have been delivered to AGDC, the Contractor shall preserve and retain all Records in its possession relating to the performance of this Agreement until the end of the later of (a) five years after the expiration or earlier termination of this Agreement, or (b) receipt by the Contractor of notice from AGDC of the final resolution of any audit findings, claims, or litigation related to the Agreement with respect to an audit, claim, or litigation for which AGDC received notice before the expiration or earlier termination of this Agreement.

17. EXAMINATION OF RECORDS. The Contractor shall permit any person designated by AGDC, at any reasonable time during regular business hours, and upon twenty-four hour notice, to examine and make audits of any and all of the Records.

18. PRIOR AGREEMENTS. This Agreement supersedes any and all prior agreements and understandings between AGDC and the Contractor relating to the subject matter of this Agreement. However, the provisions of this paragraph do not operate to release the Contractor or AGDC from any responsibilities or liability that may have arisen under any prior agreement.

19. N/A

20. PERMITS; LICENSES. The Contractor shall be solely responsible and financially responsible for obtaining all required permits, licenses, and approvals to comply with municipal, state and federal authority to operate the Contractor's own business. The Contractor, as part of its services, may assist AGDC with obtaining permits and approvals for project work performed under this Agreement; however, the Contractor shall not be financially responsible for the costs of such project-related permits and/or approvals.

21. SAFETY. The Contractor shall establish and implement, and shall take reasonable steps to assure that each of the Contractor's subcontractors establish and implement, safety procedures and practices to minimize injuries and illness to employees and others in the conduct of work under this Agreement (the "Safety Procedures").

22. CONFIDENTIALITY. The Contractor acknowledges that all information owned by AGDC is to be treated as confidential and proprietary unless AGDC specifically notifies the Contractor otherwise in writing. The Contractor agrees to protect and keep confidential all such information and will undertake to maintain the same standard of care and security to protect the confidentiality of the information as the Contractor uses to protect its own confidential and proprietary information and, in addition, shall take such reasonable steps as AGDC may require of the Contractor for that purpose. In no event may the

Contractor display any AGDC information on any website that is available to any person other than the Contractor, its subcontractors, and AGDC without prior written permission from AGDC.

The Contractor's confidentiality obligation hereunder shall not extend to information which is a part of the public domain before the disclosure of such information by the Contractor.

The Contractor shall not be restricted in any way from releasing information in response to a subpoena, court order, or other legal process, or as may be legally compelled by any tribunal or governmental or regulatory authority, but, in such event, the Contractor shall immediately notify AGDC of the demand for information before the Contractor responds to such demand.

The Contractor agrees to limit distribution of the information owned by AGDC to those of its employees who are performing work under the Agreement. The Contractor may not distribute information owned by AGDC to other parties without the express written consent of AGDC. The Contractor agrees that, upon completion of this Agreement or at any other time requested by AGDC, it will return the originals and all copies of any information owned by AGDC that is then in the Contractor's possession to AGDC. For purposes of this MSA "information owned by AGDC" means (a) the Records and (b) all information provided to the Contractor by AGDC or by another person at the request of AGDC.

23. **COPYRIGHT AND OTHER INTELLECTUAL PROPERTY RIGHTS.** The Contractor acknowledges that the work product developed under this Agreement is a work for hire specifically commissioned by AGDC. The Contractor agrees that AGDC is entitled to the copyright and all other intellectual property rights (such as, but not limited to, patents, trademarks, and service marks) in all technical materials, reports, drawings, manuals, or other work product developed pursuant to this Agreement and the Contractor hereby releases and waives any claim it may have to such copyright. At all times, each party shall retain all of its intellectual property rights with respect to property not described in the preceding sentence.

24. **LIENS.** The Contractor shall pay for all services, labor, materials, and equipment used in the execution of this Agreement and will maintain all materials, equipment, and Records free of all liens. The Contractor will, upon completion of each Task Order and before final payment is due, furnish AGDC with reasonable evidence that all services, labor, materials, and equipment have been paid in full and that any prior liens with respect thereto have been released.

25. N/A

26. **INDEPENDENT CONTRACTOR.** The Contractor and any agents, employees, officers, and subcontractors of the Contractor act in an independent capacity and are not officers or employees or agents of AGDC in the performance of this Agreement.

27. **GOVERNING LAW.** This Agreement is governed by the laws of the State of Alaska. Any actions brought as a result of this Agreement shall be brought in the courts for the State of Alaska in the Third Judicial District in Anchorage, Alaska.

28. **NO CONSEQUENTIAL DAMAGES.** Neither the Contractor nor AGDC may seek or be entitled to loss of anticipated profits or any special, indirect, or consequential damages for work resulting from this Agreement and any subsequent Task Orders.

29. **OFFICIALS NOT TO BENEFIT.** The Contractor must comply with all applicable State or federal laws regulating ethical conduct of public officers and employees.

30. CAPTIONS, SEVERABILITY. The captions and headings of the paragraphs of this Agreement are for convenience only and are not to be used to interpret or define the provisions of this Agreement. If any provision of this Agreement conflicts with applicable law, the conflict does not affect the other provisions of this Agreement which can be given effect without the conflicting provision. The provisions of this Agreement are declared to be severable.

31. EQUAL OPPORTUNITY EMPLOYMENT. The Contractor certifies that it complies with the applicable portions of 42 U.S.C. 1971, 1975 and 2000 of the Civil Rights Act of 1964 and the civil rights laws in the Alaska Statutes, AS 18.80 2 AAC 12.120 (a) (4). The Contractor further certifies that subcontracting will be allocated to meet goals established to eliminate and prevent discrimination.

32. TERM. This Agreement shall expire on September 1, 2015. AGDC, at its sole discretion, may extend this Agreement from the original expiration date set forth above by providing written notice to the Contractor before the original Agreement expiration date or before the then current Agreement expiration date.

33. FUNDING. The Contractor acknowledges that AGDC is an agency of the State of Alaska and, therefore, is only able to make payments for any purpose, including for the purpose of making any payments that may be due under this Agreement, to the extent that AGDC receives appropriations for such purpose.

IN WITNESS WHEREOF, the parties have executed this Agreement on the dates set out below. This Agreement takes effect on the date of its execution by AGDC.

Agreed to and Accepted by CONTRACTOR

By: Rigdon H Boykin
(Authorized signature)
Rigdon H Boykin
(Typewritten name/title)

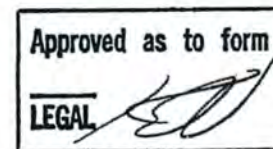
May 26, 2015
Date

Agreed to and Accepted by ALASKA GASLINE DEVELOPMENT CORPORATION

By: Bruce Tangeman
(Authorized signature)

5/28/15
Date

Bruce Tangeman / V.P. Finance + Admin
(Typewritten name/title)



**EXHIBIT A
RESERVED**

EXHIBIT B

Scope of Work

The Contractor shall provide oil and gas consulting services concerning natural gas resources, project development and project financing. Services shall include assistance in integrating the activities of AGDC with respect to the ASAP and AKLNG projects with the work of the Governor's Office, the Department of Natural Resources, the Department of Revenue, and the Department of Law. In addition the Contractor will assist in and coordinate the negotiations of the State and AGDC with the producers participating in AKLNG and possible partners in ASAP. It is understood that the Contractor is not admitted to the Bar of the State of Alaska and will not render opinions or give advice with respect to the laws or Constitution of the State of Alaska.

The Contractor shall remain in good standing with the Internal Revenue Service, the Alaska Department of Labor, the Alaska Department of Commerce, Community and Economic Development, the Fair Labor Standards Act, OSHA and other applicable authorities.

**EXHIBIT C
RESERVED**

**EXHIBIT D
RESERVED**

EXHIBIT E Invoicing and Payment

NEW CONTRACTORS / VENDORS SETUP

New Contractors will need to be set up in AGDC systems for payment of invoices. AGDC accounting will coordinate receiving the following forms from new Contractors.

- Vendor Set Up Form
- W-9, if required
- Automated Clearing House Transmission Request Form
- Alaska Business License

INVOICING ITEMS TO NOTE / REQUIREMENTS

1. Contractor shall be paid a fixed fee of \$120,000.00 per month commencing June 1, 2015 for the month of June and continuing on the first day of each month thereafter until termination of this contract or November 1, 2015, whichever occurs first. If this contract is still in effect on November 1, 2015, payment will equal \$100,000.00 per month from and after November 1, 2015, until termination; provided, however, that in no event will AGDC be obligated to pay, or liable for, an amount greater than \$500,000.00
2. Contractor shall be reimbursed for all reasonable living expenses in Alaska and travel expenses for one trip to South Carolina per month. Direct costs will be reimbursed based on submitted receipts and without mark-up,
3. AGDC does not pay local, state, or federal taxes on work performed under the Contract.
4. Contractors shall invoice monthly.
5. It is expected that most services under this contract will be performed in Anchorage, Juneau and at offices of project participants (primarily in Houston). Travel between such locations is authorized.
6. **Disputed Invoice Amounts:** AGDC may exclude unallowable amounts that are incorrectly billed on an invoice when making payments. In the event AGDC disputes any invoice item, AGDC shall give Contractor written notice of such disputed item and work with the Contractor to resolve the item. AGDC may short pay invoices for disputed items and would expect that AGDC and the Contractor will make every reasonable effort to timely resolve any disputed items.

INVOICE SUBMITTAL

Invoices and supporting documentation shall be submitted to AGDC as follows:

E-mail to: accounting@agdc.us

Or

Mail to: AGDC

Attn: Accounting

3201 C Street, Suite 200

Anchorage, Alaska 99503

INVOICE PAYMENT

Payments (other than disputed amounts described in paragraph 6 above) are due the Contractor no later than thirty calendar days following AGDC's receipt of an invoice.

NOTICE

Unless and until AGDC otherwise notifies the Contractor in writing, the Contractor shall send all notices required under the Agreement to the following address in accordance with paragraph 15 of the Agreement:

Alaska Gasline Development Corporation
Attn: (Contract Manager)
3201 C Street, Suite 200
Anchorage, Alaska 99503

Alternatively, and in accordance with the provisions of paragraph 15, of the Agreement, the Contractor may send notices and otherwise communicate to AGDC by email using the email address provided to the Contractor by the Contractor's contact person at AGDC.

Unless the Contractor otherwise notifies AGDC in writing, AGDC shall send all notices required under the Agreement to the Contractor at the address or email address provided by the Contractor in writing to AGDC.

**EXHIBIT F
RESERVED**

EXHIBIT G
Subcontract Rider

This Subcontract Rider is entered into by and between _____ (the "Contractor") and _____ (the "Subcontractor") and is dated _____, 20__.

WHEREAS, the Contractor has entered into a contract (the "Contract") with the Alaska Gasline Development Corporation ("AGDC"), a public corporation of the State of Alaska organized and existing under AS.31.25; and

WHEREAS, pursuant to the Contract, the Contractor will perform certain work as described in the Contract; and

WHEREAS, the Contractor now wishes to enter into a subcontract with the Subcontractor (the "Subcontract") to provide for work from the Subcontractor in furtherance of the Contract; and

WHEREAS, the Contractor and the Subcontractor will attach this Subcontract Rider to any contract or agreement between them for the provision of such services;

NOW, THEREFORE, THIS SUBCONTRACTOR RIDER WITNESSETH:

1. The Subcontractor agrees that all payments and reimbursements owed to the Subcontractor under the Subcontract are the responsibility of the Contractor and that AGDC has no liability or responsibility under the Contract or under the Subcontract for any such payments.
2. The Subcontractor agrees that AGDC has no liability or responsibility for any other term or provision of the Subcontract, and the Subcontractor shall not attempt to pursue remedies for any portion of the Subcontract against AGDC.
3. In performing work under the Subcontract, the Subcontractor may receive or view information that belongs to AGDC. The Subcontractor agrees that it will treat all such information as confidential unless and until it receives written notification otherwise from AGDC. The Subcontractor further agrees to observe all the requirements imposed on the Contractor under paragraph 22 of the Contract (relating to confidentiality).
4. The Subcontractor agrees to indemnify AGDC to the same extent and in the same manner as required of the Contractor pursuant to paragraph 13 of the Contract (relating to indemnification).
5. The Subcontractor agrees that no part of the Subcontract may be assigned or delegated without the express and prior written consent of AGDC.
6. All records related to work performed by the Subcontractor under this Subcontract are property of AGDC and shall be subject to the terms of paragraphs 16 (relating to ownership of records) and 17 (relating to examination of records) of the Contract as though "Contractor" in those paragraphs means "Subcontractor" and "Contract" means "Subcontract."

7. The Subcontractor shall maintain insurance as required of the Contractor under paragraph 19 of the Contract (relating to insurance) and in accordance with the terms and conditions of said paragraph 19.

8. Any notices or other communications required to be sent to AGDC for purposes of this Subcontractor Rider shall be sent as follows:

Alaska Gasline Development Corporation
3201 C Street, Suite 200
Anchorage, Alaska 99503

9. The Contractor and the Subcontractor agree to attach this Subcontractor Rider as an appendix or exhibit to the Subcontract and to cause this Subcontractor Rider, by such attachment, to become part of the Subcontract. The Contractor and the Subcontractor agree that, to the extent there is a conflict between the terms of this Subcontractor Rider and any other terms of the Subcontract, the terms of this Subcontractor Rider shall control.

10. The Contractor and the Subcontractor agree that AGDC is a third party beneficiary to this Subcontractor Rider and shall have all the rights and powers that a party to this Subcontractor Rider would have in the enforcement of the terms hereof and the pursuit of remedies.

CONTRACTOR

SUBCONTRACTOR

By: _____

By: _____

Current Debt Position

As of June 30, 2014 the State of Alaska ("State") had approximately \$1.3 billion in General Obligation debt outstanding. The State has traditionally has adopted a very conservative stance towards general obligation bond funding, as the State employed pay as you go strategy as a primary source of capital.

As of June 30, 2014, the State had additional commitments, included in the calculation of net tax supported debt, of approximately \$248 million in Certificates of Participation and \$268.8 million of capital lease obligations securitized through political subdivisions that were authorized by Alaska Law.

Rating agency reports have commended the State's conservative financial management, citing a low debt burden and increased reserve amounts to offset any unanticipated shift in the price or production of oil. While the State currently relies on North Slope oil production for revenues, there are long term alternatives being considered in natural gas and mineral production generated revenue, potential implementation of a State-wide broad based tax, and the potential use of earnings of the Permanent Fund to offset costs of government services. The State's current debt position is very conservative and, as a result, the State has maintained a level of flexibility not experienced by many other states in funding for capital projects.

Evidence of the conservative nature of the State's debt practices is witnessed by the relatively low level of debt service as a percentage of unrestricted general fund revenue. While the current State policy is designed to limit this ratio to 8%, for the last ten years the State has remained below 5% and was 3.3% for fiscal year 2013. In addition to the low level of debt service as a percentage of unrestricted general fund revenue, another metric demonstrating the conservative debt position of the State is the trajectory of general obligation debt retirement. Approximately 70% of the current general obligation debt outstanding will amortize and retire over the next 10 years, allowing for increased flexibility for the State to participate and support in large scale projects.

The State has traditionally utilized long-term fixed rate debt in relation to its general obligation bond issuance. This, in turn, has resulted in no exposure to floating or variable rate debt as well as swaps and other derivative products used to hedge interest rate risk. While it is recognized that agencies of the State use variable rate debt and derivative products, no direct exposure exists for the State and the risks associated with such products are not found in the States general obligation bond indebtedness.

The State's ability to fund capital projects with current revenues has played a significant factor in the relatively low level of general obligation debt for the State. The reliance on current revenues has limited the State's need for bond issuance as a funding source and as a result has allowed the State to maintain a flexible debt profile.

Affordable Level of Additional Debt or Obligations

The State of Alaska is 2nd lowest of all the 50 states for debt service as percent of budget/revenues. The range for AAA rated States is 0.9% (Iowa) up to 8.2% (Delaware), so it is very hard to say how much additional debt could result in a downgrade for the State. The State of Alaska was at 1.2% in 2013. However, in other debt ratios, the State is much closer to, and sometimes above, the medians for all states. Median ratings are AA+/Aa1, so the State of Alaska has no capacity to increase debt with the other rating factors (debt as % GDP, personal income, etc.) particularly because the trends have been for these ratios to decrease (i.e. improve credit strength). So, by taking on additional debt, the State would be going against national trends and any capacity vs current medians is likely to decrease. Only four states have debt service ratios above 10%: CT (Aa3), MA (Aa1), IL (A3) and NY (Aa2)—so going above 10% is very unusual and could put the State in a precarious position (again the revenue concentration would most likely be a factor).

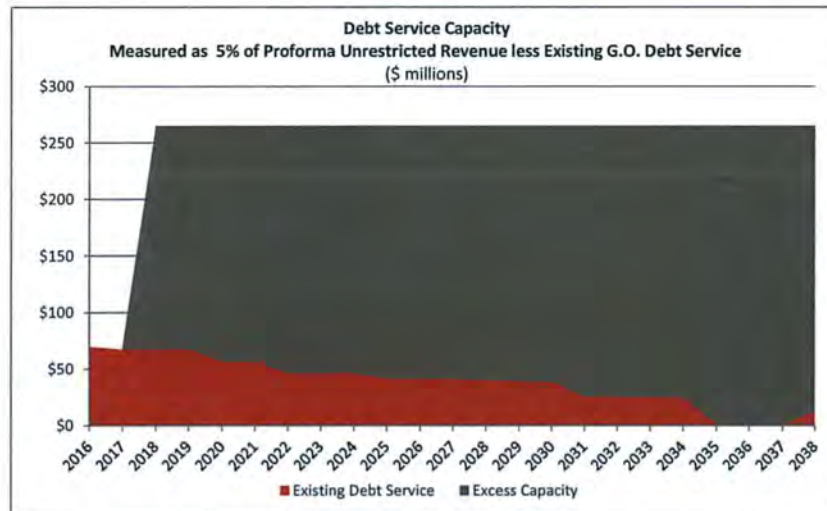
As of result of the above rationale, FirstSouthwest has developed a debt capacity model which will enable the State to calculate its available borrowing capacity to meet its future capital needs. The model results are based on the following constraints:

(Current AAA Rating)

- Debt service in any year cannot exceed the targeted level of 5% of the prior year's revenues;
- All future debt issuances are structured as tax-exempt bonds amortized over 20 years, with level debt service payments;
- All bonds are issued at an assumed interest rate of interest based on the assumed rating; and
- Annual unrestricted revenues available to pay debt service through 2023 are set at amounts stipulated in the Fall 2014 Revenue Sources Book of the Department of Revenue's Tax Division.

Based on these assumptions, FirstSouthwest has determined the State has the capacity to issue up to \$3.3 billion in debt over the next 10 years and still meet its 5% debt service ratio. As previously noted, the term "debt" includes all the State's outstanding general obligation and state-supported debt. Lowering the ratio limit below 5% will necessarily reduce the amount of debt that can be borrowed over this time period. Conversely, raising the ratio limit to 8% will produce an additional \$2.3 billion of debt capacity over this time period.

The graph below depicts the State's debt service capacity while maintaining the 5% debt service ratio. The red area on the graph shows the State's existing annual general obligation debt service, while the remaining amount, depicted in the graph as the grey shaded area, displays the excess capacity available to the State to accommodate the issuance of up to \$3.3 billion in additional debt while still maintaining the 5% debt service ratio and AAA rating.

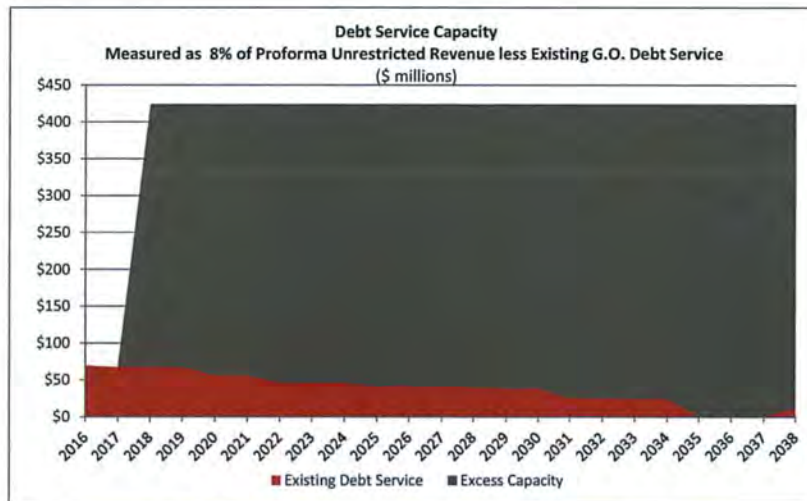


(AA+ Rating)

- Debt service in any year cannot exceed the targeted level of 8% of the prior year’s revenues;
- All future debt issuances are structured as tax-exempt bonds amortized over 20 years, with level debt service payments
- All bonds are issued at an assumed interest rate of interest based on the assumed rating; and
- Annual unrestricted revenues available to pay debt service through 2023 are set at amounts stipulated in the Spring 2014 Revenue Sources Book of the Department of Revenue’s Tax Division.

Based on these assumptions, FirstSouthwest has determined the State has the capacity to issue up to \$5.6 billion in debt over the next 10 years and still meet an 8% debt service ratio, but with the assumption the State will be revised to a AA+ rating. As previously noted, the term “debt” includes all the State’s outstanding general obligation and state-supported debt.

The graph below depicts the State’s debt service capacity while maintaining the 8% debt service ratio with a AA+. The red area on the graph shows the State’s existing annual general obligation debt service, while the remaining amount, depicted in the graph as the grey shaded area, displays the excess capacity available to the State to accommodate the issuance of up to \$5.6 billion in additional debt with a 10% debt service ratio and AA+ rating.



(AA Rating)

- Debt service in any year cannot exceed the targeted level of 10% of the prior year’s revenues;
- All future debt issuances are structured as tax-exempt bonds amortized over 20 years, with level debt service payments;
- All bonds are issued at an assumed interest rate of interest based on the assumed rating; and
- Annual unrestricted revenues available to pay debt service through 2023 are set at amounts stipulated in the Spring 2014 Revenue Sources Book of the Department of Revenue’s Tax Division.

Based on these assumptions, FirstSouthwest has determined the State has the capacity to issue up to \$7.1 billion in debt over the next 10 years and still meet a 10% debt service ratio, but with the assumption the State will be revised to a AA rating. As previously noted, the term “debt” includes all the State’s outstanding general obligation and state-supported debt.

The graph below depicts the State’s debt service capacity while maintaining the 10% debt service ratio with a AA. The red area on the graph shows the State’s existing annual general obligation debt service, while the remaining amount, depicted in the graph as the grey shaded area, displays the excess capacity available to the State to accommodate the issuance of up to \$7.1 billion in additional debt with a 10% debt service ratio and AA rating.

