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ConocoPhillips
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August 19, 2015

Catherine P. Foerster, Commission Chair
Alaska Oil and Gas Conservation Commission
333 W. 7th Ave #100
Anchorage, Alaska, 99501-3539

RE: Docket Numbers: AIO 15-032, AIO 15-033, CO 15-09 – Prudhoe Bay Unit

ConocoPhillips Comments to BP Exploration (Alaska) Inc. (BPXA) and ExxonMobil Alaska Production, Inc. (EMAP) July 17, 2015 Consolidated Application for Amendment of Prudhoe Oil Pool Rule 9 and Modification of Prudhoe Bay Unit Area Injection Orders AIO 3A and AIO 4F

Dear Commissioner Foerster,

ConocoPhillips Alaska, Inc. (CPAI) submits, on behalf of itself and Chevron U.S.A. Inc. (CUSA), both Prudhoe Bay Unit (PBU) working interest owners, the following comments to the above-referenced application (BPXA and EMAP Consolidation Application), and respectfully requests that the Alaska Oil and Gas Conservation Commission (Commission):

(i) Approve BPXA's and EMAP's request to increase the Rule 9 maximum allowable gas offtake rate, but to a maximum offtake rate of 3.6 billion standard cubic feet per day (bscf/d) annual average, rather than the 4.1 bscf/d annual average requested by BPXA and EMAP;

(ii) Approve BPXA's and EMAP's request to modify relevant area injection orders to permit injection of carbon dioxide (CO2) and other gas treatment byproducts for purposes of enhanced oil recovery (EOR) and pressure maintenance; and, in addition to BPXA's and EMAP's request, also approve injection of CO2 and other gas treatment byproducts for disposal in appropriate intervals, in the event that EOR or pressure maintenance opportunities that result in increased POP hydrocarbon recovery are not identified; and

(iii) Include in Rule 9 and relevant area injection orders provisions, as necessary, to permit administrative approval of future modifications.

A. CPAI Supports BPXA's and EMAP's Request to Increase the Rule 9 Maximum Allowable Offtake Rate, But Requests the Commission Approve a Rate – 3.6 bscf/d – Commensurate With the AKLNG Design Basis and Reasonably Expected Gas Volume Needs

As the Commission is aware, CPAI has been working closely with the other PBU working interest owners (WIOs), to support a request to the Commission to increase the current 2.7 bscf/d annual average Rule 9 maximum gas offtake rate for the Prudhoe Oil Pool (POP), as an important part of making possible potential major gas sales from PBU through the Alaska LNG Project (AKLNG).

Affiliates of BPXA, EMAP and CPAI, together with agents of the State of Alaska, have advanced AKLNG pre-FEED engineering, and AKLNG is expected to enter FEED[1] next year. Increasing the Rule 9 maximum annual average offtake rate will provide additional certainty to support an AKLNG FEED decision, as well as subsequent decisions to construct and operate AKLNG. In this regard, CPAI always has supported, and continues to support, requesting that the Commission increase the Rule 9 maximum allowable POP offtake rate.

As the Commission likely is aware, until June, CPAI supported considering an increase to the maximum annual average POP offtake to 4.1 bscf/d, where that daily rate would be available if the PBU WIOs determined to supply additional gas to the AKLNG gas treatment plant (GTP), in the event of a temporary non-POP gas supply disruption.

As explained below, after further consideration, CPAI has determined that 3.6 bscf/d annual average POP offtake is more than sufficient to accommodate full AKLNG GTP supply from the POP for the full duration of any reasonably expected non-POP gas supply disruption. Accordingly, CPAI requests that the Commission approve 3.6 bscf/d as the Rule 9 maximum allowable annual average POP offtake rate.

1. Governor Walker's June 8 Letter Defined Reasonable Expectations For the Duration of Non-POP Gas Supply Disruption

On June 8, Governor Walker sent a letter to BPXA, EMAP and CPAI. The Governor shared the June 8 letter with the Alaska Legislature on June 15.[2] The Governor's letter provided helpful clarity regarding necessary gas supply terms to support AKLNG, including the duration of potential non-POP gas supply disruption.

Appendix A of the Governor's June 8 letter lays out a preferred commercial structure comprised of two joint ventures: one receiving PBU gas and one receiving PTU gas (PTU being the non-POP gas supply source to AKLNG), and treating, transporting and liquefying the gas through AKLNG capacity reserved for each source of supply. Appendix A notes that the Prudhoe Bay joint venture and the Point Thomson joint venture may enter into certain mutual aid arrangements: one month of mutual aid per year, in case of downtime caused by operational issues; and two months of mutual aid on a one-time basis, in case of severe disruption.

This proposal from the Governor defined reasonable expectations regarding maximum durations over which 100% POP offtake rate *could* be required: at most, one month on an annual basis; at most, two additional months, in case of once-in-field-life emergency.

These maximum durations are conservative, safe assumptions, well in excess of typical industry or North Slope downtimes. So far as CPAI is aware, no major North Slope field ever has experienced an operational issue that caused the field to be entirely offline for three months. The longest major shutdown of which

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[1] Front-End Engineering and Design (FEED) is the final engineering phase before AKLNG sanction, or final investment decision (FID). The AKLNG parties are expected to determine whether to enter FEED in 2016, and to determine whether to approve FID in 2019.

[2] The Governor's June 15 and June 8 letters are Attachment 1 to these comments.

CPAI is aware occurred in October 2006 when approximately 30% of PBU production was shut in for 82 days, due to transit line issues.

2. 3.6 bscf/d Is the Appropriate Maximum POP Offtake Rate At This Time

Taking into account the AKLNG design basis, premised POP and non-POP AKLNG supply, reasonable expectations regarding PTU downtime, minimization of PBU liquid impacts, and the basic premise that 4.1 bscf/d could be used as an excursion rate, available if the PBU WIOs determined to supply additional gas to the AKLNG GTP, in case of a temporary non-POP gas supply disruption, 3.6 bscf/d is the appropriate maximum annual average POP offtake rate at this time.

3.6 bscf/d annual average maximum offtake provides more than sufficient capacity, even in case of a worst-case 3 month period of 100% PTU downtime in a single year. In fact, a maximum annual average offtake of 3.6 bscf/d would allow for the PBU WIOs to supply 100% of AKLNG GTP inlet volume for approximately 4 months in one year.[3]

3. 3.6 bscf/d Annual Average Offtake Is More Than Sufficient for AKLNG

AKLNG FEED is estimated to cost approximately $2 billion. Accordingly, the decision to enter FEED will require certainty on many issues to support such a large commitment. The current shared goal of BPXA, EMAP and CPAI is to secure an increase to the current Rule 9 maximum allowable offtake rate from the POP, to provide certainty regarding available POP gas, which would be a key factor supporting a 2016 AKLNG FEED decision, as well as subsequent decisions to build and operate AKLNG. A 3.6 bscf/d annual average rate would provide more than sufficient certainty regarding POP gas availability, based on reasonable expectations of maximum PTU downtime in any year.

4. The Commission Should Defer Consideration of an Offtake Rate Higher Than the 3.6 bscf/d Annual Average Rate Required for AKLNG

The 3.6 bscf/d annual average POP offtake rate will be more than sufficient to supply AKLNG. However, if AKLNG does not proceed, and if another gas commercialization project is later developed, with different gas sources, or a different basis of design, then it would be appropriate for the Commission to reevaluate POP offtake in light of that new technical information, and then-current POP reservoir and other information.

5. PTU Is Premised to Provide 25% of the Gas to AKLNG; However, If PTU Start Up Is Materially Delayed or PTU Resources Are Materially Less Than Predicted, There Will Be More Than Sufficient Time to Amend the POP Offtake Rate, If Appropriate

BPXA's and EMAP's application states that additional POP rate may be required "during startup of, or after gas production begins to decline from, other fields".[4] CPAI does not entirely understand this statement.

It may suggest that BPXA and EMAP perceive a real risk that PTU start-up will be materially delayed, after AKLNG start-up currently premised in 2025. CPAI also is a PTU owner, and is not aware of such a risk, especially in light of the extent of work that will have been completed by next year for IPS. As far as CPAI is aware, excepting TAPS, no North Slope project similar to (or larger than) PTU gas expansion has been delayed more than 3 months. Further, given the complexity and scope of AKLNG (currently estimated to

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[3] CPAI's requested 3.6 bscf/d POP maximum annual average offtake rate is comprised of 2.7 bscf/d normal AKLNG GTP supply, 0.6 bscf/d for fuel gas, other field operations, and minor North Slope sales, plus 0.3 bscf/d to allow for the POP to supply 100% of AKLNG GTP inlet volume for up to four months in one year. In this regard, if POP offtake occurred at 4.1 bscf/d for 4 months, and at 3.3 bscf/d for 8 months, then the annual average offtake rate would be approximately 3.6 bscf/d.

[4] BPXA and EMAP Consolidated Application, at 4.

cost $45-$65 billion), it is much more likely that AKLNG – not PTU – would be the source of any material start-up delay.

However, if AKLNG did start-up in 2025, and if PTU start-up were materially delayed after AKLNG start up, and the PBU WIOs wished to supply the AKLNG GTP during the period of PTU delay, CPAI anticipates the Commission could timely consider a short term increase to the Rule 9 offtake rate at that time. As construction progress will be closely tracked against critical path schedules, the PBU WIOs would know likely at least one year in advance if PTU start up would be delayed more than four months.[5]

In any event, given the low likelihood of material PTU delay – a successful AKLNG project is premised on simultaneous start-up of all project and related upstream systems – there is no need for the Commission to grant a POP annual average offtake rate higher than 3.6 bscf/d at this time.

The same is true if, in relation to BPXA's and EMAP's statement that additional POP supply may be required "after gas production begins to decline from . . . other fields".[6] This statement appears to suggest that if PTU declines much faster than expected, supply from the POP will be needed to cover the difference. As far as CPAI is aware, this is unlikely. The PTU operator has provided very high quality information validating PTU resources. The IPS Project will provide additional validation. CPAI expects there will be a low likelihood that PTU will decline much faster than anticipated.

However, in the unlikely event that PTU declines much faster than expected, and the PBU WIOs wished to supply additional gas from the POP, there would be sufficient time to request an appropriate Rule 9 increase.[7] AKLNG start-up currently is premised to occur in 2025. Accelerated PTU decline, if it were to occur, would occur many years after 2025 start-up.

In sum, material PTU delay and materially accelerated PTU decline are both unlikely events. If either ever occurred, a PBU offtake increase could be timely considered by the PBU WIOs and the Commission, if appropriate, at that time.

B. CPAI Supports BPXA's and EMAP's Request to Allow GTP Byproduct Injection for EOR and Pressure Maintenance, But Further Requests That the Commission Allow Disposal of GTP Byproducts in Appropriate Intervals Through Class II Wells

CPAI supports BPXA's and EMAP's request to inject GTP byproducts, principally comprising CO2, into appropriate intervals within the PBU, for EOR and pressure maintenance. However, CPAI notes that the benefit BPXA and EMAP identify in connection with such injection – approximately 3.8 billion barrels of oil equivalent – is the total gas recovery associated with major gas sales into AKLNG.[8] This additional recovery is very material, but it is not an EOR benefit. BPXA and EMAP have not identified actual EOR benefits in their application.[9]

However, AKLNG start up is premised to occur in 2025, so there are many years in which to investigate additional EOR opportunities. In this regard, CPAI requests that the Commission grant BPXA's and EMAP's

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[5] Further, unless AKLNG start up is to occur on the first of a calendar year, a 3.6 bscf/d maximum offtake rate would allow offtake from the POP at 4.1 bscf/d for longer than four months in that year (as the daily rates are averaged over the entire calendar year), which would afford additional flexibility.
[6] BPXA and EMAP Consolidated Application, at 4.
[7] CPAI requests that the Commission include, as necessary, provisions in Rule 9 and relevant area injection orders to permit administrative approval of future modifications.
[8] BPXA and EMAP Consolidated Application, at 5.
[9] The Consolidated Application does not identify "an expected increase in incremental hydrocarbon recovery" from CO2 injection. 20 AAC 25.402(c)(14).

request to approve GTP byproduct injection for EOR and pressure maintenance, in anticipation that there may be EOR opportunities later identified.

However, in the event that EOR opportunities are not later identified, CPAI also requests that the Commission approve disposal of GTP byproduct in appropriate intervals in Class II PBU wells.[10]

C. Supporting Information

CPAI will have appropriate experts available at the public hearing to testify regarding these comments. Depending on the testimony presented by others, CPAI reserves the right to present additional testimony at the public hearing, or by post-hearing submission, if so authorized by the Commission.

D. Conclusion

Based on the above comments, CPAI respectfully requests that the Commission:

(i) Approve BPXA's and EMAP's request to increase the Rule 9 maximum allowable offtake rate, but to a maximum offtake rate of 3.6 bscf/d annual average, rather than the 4.1 bscf/d annual average requested by BPXA and EMAP;

(ii) Approve BPXA's and EMAP's request to modify relevant area injection orders to permit injection of CO2 and other gas treatment byproducts for purposes of EOR and pressure maintenance; and, in addition, also approve injection of CO2 and other gas treatment byproducts for disposal in appropriate PBU intervals, in the event that EOR or pressure maintenance opportunities that result in increased POP hydrocarbon recovery are not identified; and

(iii) Include in Rule 9 and relevant area injection orders provisions, as necessary, to permit administrative approval of future modifications.

Please contact Eric Reinbold at 907-263-4465 if the Commissioners or Commission staff have any questions regarding these comments. Please direct communications regarding procedural matters, including the public hearing, to John Evans, counsel for CPAI, at 907-265-6329.

Sincerely,

Jon Schultz, Manager, Greater Prudhoe Area
ConocoPhillips Alaska, Inc.

Concurring for Chevron U.S.A. Inc.

J.M. Woliver, NOJV Manager
Chevron North America Exploration and Production Company,
a division of Chevron U.S.A. Inc.

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[10] CPAI recognizes that the Commission will need additional information under 20 AAC 25.252 to approve a disposal request; however, this information can be readily provided by the PBU operator. Relevant to 20 AAC 25.252(c), as noted in BPXA's and EMAP's Consolidated Application, there is no risk of movement of fluids into sources of freshwater or underground drinking water. BPXA and EMAP Consolidated Application at 6.

Attachment 1 – June 15 and June 8 Letters from the Governor of the State of Alaska

cc via email:

Gilbert Wong, EMAP (gilbert.wong@exxonmobil.com)
Steve Luna, EMAP (charles.s.luna@exxonmobil.com)
Phil Ayer, CUSA (pmayer@chevron.com)
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Attachment 1

June 15 and June 8 Letters from the Governor of the State of Alaska

See attached.

STATE CAPITOL
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Governor Bill Walker
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June 15, 2015

The Honorable Kathy Giessel
Alaska State Senate
716 W. 4th Ave. Suite 511
Anchorage AK, 99501

The Honorable Benjamin Nageak
Alaska State House of Representatives
State Capitol Room 126
Juneau AK, 99801

The Honorable Dave Talerico
Alaska State House of Representatives
1292 Sadler Way Suite 328
Fairbanks AK, 99701

Dear Senate and House Resource Committee Chairs and Co-Chairs:

I want to inform you about the efforts of my administration to move the AK LNG project ahead. Attached is my letter dated June 8, 2015 to the heads of the producers' negotiating teams for the AK LNG project. We have identified a lack of urgency in the parties' resolution process. The methodology that the AK LNG team adopted for identifying problems and issues is excellent. However, there does not appear to be much process associated with resolving issues between the parties, and certainly not one with a sense of time urgency.

It is time to build this gas pipeline to Nikiski, and therefore the state needs to take the lead and proactively mediate and find resolutions within a time frame that will keep the project on schedule. The attached letter proposes a time frame and process for moving the issues to resolution.

To date, the producers have been working towards a 2nd quarter-2016 FEED decision. This meshes efficiently with a fall special session for legislative review of the proposed agreements. It also works well should voter consideration of a November 2016 constitutional amendment be required in addressing the fiscal certainty needs of the project. For these reasons, schedules should not be allowed to slide. Assuming that all the producers match the State's commitment to commercialize North Slope gas, we must push ourselves to close out these issues.

The attached letter identifies the key issues requiring resolution and the state's position on those issues. My hope is that with clarity of focus and attention, the producers and the state can stay the course on their intended timeline and give Alaskans a gas pipeline project from the North Slope to Nikiski that will provide the next generation the revenues they need to build a prosperous future.

Sincerely,

Bill Walker
Governor

cc: Janet Weiss
Dave VanTuyl
Joe Marushack
Pat Flood
Bill McMahon
Jim Flood

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June 8, 2015

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22777 Springwoods Village Parkway
Spring, Texas 77389

Dear AK LNG Sponsors:

A few weeks ago, we jointly set a goal to finalize the term sheets for all major project enabling contracts by the middle of June. It is now June 8th. Despite the efforts of all parties, it is clear we are not on schedule to achieve this goal.

There are at least two major issues and at least three smaller major issues. I have summarized the State's listing of those issues along with my comments.

I am asking that this list be considered by the VAMOU on Tuesday to determine if consensus can be reached on the completeness of the list. The goal would be to gain agreement on a final list of major issues in order for our respective negotiating teams to share a common focus and issue prioritization. The resulting list would then be presented at the Sponsor Meeting on Wednesday with the Sponsor representatives tasked to resolve these major issues – especially the two large major issues. Resolution of these major sticking points will be a catalytic event enabling substantial progress on finalizing the terms of the project contracts.

To the extent there are issues remaining after the Sponsor Meeting where the parties are substantially apart, I would like the State to engage in a shuttle diplomatic effort with producers, with a goal of gaining issue closure or at least a clear understanding of the extent of remaining disagreement. Following the best efforts of our teams to reach closure on the major issues, I

would like to meet face to face during the week of June 15th with each Sponsor executive individually to attempt to resolve the remaining issues. I would like to resolve the major issues in these meetings so we can begin the process of drafting contracts

The AK LNG team will be briefing the Legislature on the 16th of June in Kenai, Alaska. After months of expectation, the people of Alaska and their elected representatives are anxious for concrete progress.

Large Major Issues

1. The largest issue is Joint Venture Marketing vs. Equity Marketing.
   The State believes it will be very difficult, if not impossible, for this project to proceed with the PBU and PTU fields with all the current participants outside a Joint Venture Marketing context.

2. Upstream issues – to the extent they are not resolved by Joint Venture Marketing. Most of the remaining upstream issues can be resolved through the use of separate Joint Ventures that would receive the gas from the PBU and PTU fields with support between the two Joint Ventures along the lines of the proposal attached as Appendix A.

Other Major Issues

3. Fiscal Stability: It will only deal with the gas dedicated to this Project from PBU and PTU. It will not include oil. The State is willing to consider a 25 year term in order to facilitate integrated project financing. The State believes a Constitutional Amendment will provide the certainty that all parties would like. Attached as Exhibit B is an example of what I envision the constitutional amendment might look like.

4. 48 inch line: Constructing a 48 inch line will alleviate the issues of open access and expansion. The Producers have stated they do not need or want a 48 inch line. The State is willing to pay for this expansion subject to legislative approval, but it would own all the benefits of the increased size. The State would also pay for installing the valves, pads etc. to accommodate four more compressor stations that will be added when demand exists from new developments or fields. The State intends to use this expansion capacity to encourage open access.

5. East vs. West Cook Inlet crossing: It is my understanding that the studies for the two routes are under way but that the tentative conclusion at this point in time is that the Western Route is the preferred alternative. The Matsu Valley constitutes the second largest population base in the State of Alaska and has some of the highest industrial potential in the State. Consequently, the State strongly prefers the Eastern Route since the studies to date do not indicate any insurmountable obstacles. Also, the Eastern Route will better enable this Project to better fulfill the statutory domestic gas mandate.

Sincerely,

Bill Walker
Governor

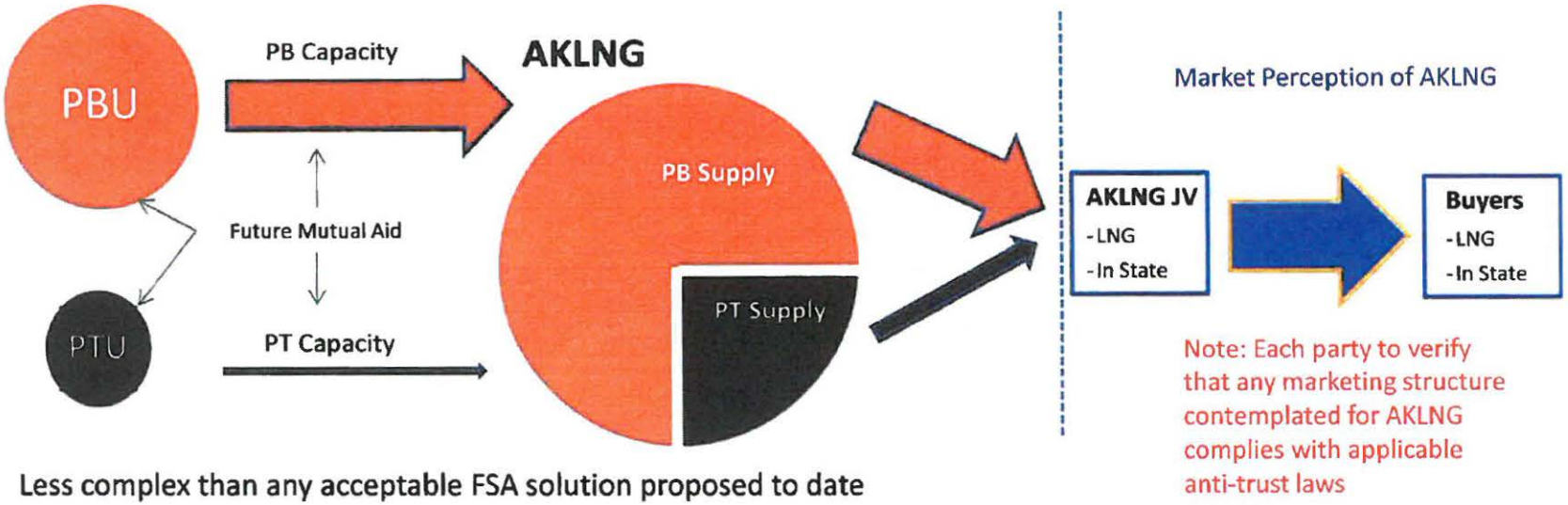
Enclosure

Appendix A – Joint Venture Marketing Model
Appendix B – Sample Draft Constitutional Amendment

cc: Dona Keppers, SOA, Deputy Commissioner of Revenue
Dan Fauske, AGDC
Steve Wright, SOA, Department of Natural Resources
Audie P. Setters, SOA, Gas Team, General Manager

Appendix A

Joint Venture Marketing Model



Less complex than any acceptable FSA solution proposed to date

- Can explain to buyers, lenders and other State stakeholders
- The JV revenue flows back to Titleholders in proportion to their respective participation
- Any JV costs (including SPA penalties) flow back to Titleholders in proportion to their respective participation
- The JV nominates supply from each Unit, and takes title at entry point to the relevant Transmission Line

Gas Balancing and Mutual Aid:

- One month of borrow/loan gas each year for operational issues:
  - to be repaid in kind within one calendar year;
  - In place for 15 years after start-up
- One time gas purchase option (approx. 2 months of PTU downtime):
  - 80 BCF (20 cargos) on an energy basis
  - Expires lesser of 5 years after triggered or year 15.
- JVs can "bank" gas to ensure access to additional future gas;
- Good faith mutual assist provision to ensure JVs avoid reputational damage to AKLNG (dropped cargos)

APPENDIX B

Sample Draft Constitutional Amendment

* Section 1. Article IX, Constitution of the State of Alaska, is amended by adding a new section to read:

> **Section 18. Suspension of Taxation by Contract Authorized by Law.** Contracts approved by a majority of the legislature and entered into by the executive branch by December 31, 2017 to provide fiscal terms for a liquefied natural gas project, including a gas treatment plant, gas pipelines, and a liquefied natural gas plant and related facilities, as provided by law are constitutional under this article. Such contracts as originally executed shall be binding upon future legislatures as to terms of gas taxation, but any amendments to such contracts executed between the parties shall not bind future legislatures as to any aspect of taxation.