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would decline jurisdiction over this major interstate natural gas pipeline system is remote and far fetched. It should be noted that the fiscal contract does not change or restrict the jurisdiction of the RCA so in the remote hypothetical postulated, the RCA would be free to assert whatever lawful jurisdiction it might have over some element of the project. The fiscal contract requires the parties to the contract to support FERC jurisdiction. This objective was shared by everyone who testified on this issue. With respect to the remote possibility that project facilities might be subject to commercial agreements, the administration is proposing language that any such commercial agreement must be consistent with FERC principles of regulation. This addresses any lingering concern about fair access.

27. Contract Provisions Regarding Deference to, or Presumptions in Favor of, State Interpretations and Conforming Other Agreements to the Contract. The basic concept of the fiscal contract is to create a comprehensive contractual framework governing the fiscal issues that affect the successful development of a gas project. It was essential that there be a clear understanding of the relationship of pre-existing agreements among the parties that addresses issues resolved in the fiscal contract and the contractual provisions themselves. That is what Article 41.3 solves. Otherwise, the private parties to the fiscal contract would be left in a state of confusion and uncertainty over which provisions governed. Your suggestion can only be read as suggesting either that (1) a state of uncertainty is preferable, or (2) the fiscal contract should not address issues that have an economic impact on the project but were addressed in prior agreements. Neither suggestion is consistent with the purposes of the SGDA.

Equally, your suggestion about preserving presumptions in favor of State interpretations or deference towards the State is not consistent with an established, balanced, contractual resolution of all fiscal issues that affect the development of the project. Some of those presumptions simply do not apply because of the different structure with respect to the State's role of having direct responsibility for the sale of royalty and tax gas. In other cases, where appropriate, presumptions were preserved. See Article 19.10.

28. Ignoring the Advice of Experts. Many Experts were Hired by DNR and by Legislative Budget & Audit Committee (LB&A) and by other Departments. Having their Advice Ignored is a Travesty of the Best Interest of the State. This is an incorrect statement by a wide margin. Much of the consulting work done by experts hired by the DNR or working under guidance of the DNR was effectively used to the best interest of the State. For example:

- The work done by the pipeline engineering firm (Paragon) was used to do due diligence on the initial cost estimates of the Producers:

- The work of Lukens Energy was used to arrive at an average price forecast of $5.50 used in much of the economic studies and was used to develop the tariff methodology for the various economic models;

- The work of Lukens Energy was also used to determine the benefit of the "higher of" as well as the differential between Chicago and Alberta in the economic models;

- The work of Lukens Energy was used in negotiating capacity management provisions that reduced the risks it identified in an earlier draft; and,

- The work done on the DNR economic model served to validate and confirm the results of models of the Department of Revenue (DOR) and Dr. Pedro van Meurs.

Many of the views expressed by the LBAC and LBAC consultants were taken into consideration in the development of the fiscal contract and in the development of the proposed changes to the contract. However, after analysis, we found many of the criticisms to be misplaced. Thus, we did not ignore the criticisms; we simply disagreed with them and did not adopt them.

A Law of General Application. The administration just proposed and achieved passage of a law of general application—the PPT. The PPT has now been adopted which includes specific and quantifiable incentives for any entity willing and able to commit to the construction of new gas and gas condensate fields on the North Slope, which could underpin the construction of the gas pipeline. This PPT law specifically moved the point of production in order to ensure that entities willing to invest in gas processing would benefit from these incentives. Furthermore, this PPT law specifically provided significant support for smaller companies to enter into the exploration and development of new gas resources. At the same time the PPT law will make the development of liquids at Point Thomson a much more attractive proposition. This will increase the probability that the development of an initial cycling project is economic. This could provide a strong stimulus to the subsequent construction of the gas pipeline.

It should be noted that the Port Authority did not request fiscal incentives to build the gas pipeline. The matter of fiscal incentives was not high on the agenda of TransCanada either. The reason is that these were midstream projects and pipeline companies can pass on taxes in the pipeline tariff. However, without upstream fiscal protection, there is no realistic chance that the Producers would commit their gas under lease to a midstream project.

However, more fundamentally, the proposal for a law of general application for incentives for building a gas pipeline that could apply to any developer, again indicates a complete failure to understand the basic economics of the Alaska gas pipeline project. The project is not about the construction of the pipeline itself. The fiscal contract should address a complete project—one that relates to encouraging Producers or buyers of the gas to make the respective FT commitments (and in case of buyers the gas purchase and sale agreements) that

underpin the construction of a gas pipeline. Anyone can construct a pipeline if investors are willing to make the FT commitments.

The problem so far has been that we have not found Producers that are willing to make the FT commitments on a full commercial risk basis without providing for a fiscal contract on the gas that provides for fiscal stability. Nor have we found buyers willing to buy gas for favorable prices that are willing to assume FT commitments (nor will we find such buyers at $4.26/mcf gas). As long as we do not have investors willing to consider making the FT commitments, there will be no gas pipeline, regardless of a law of general application on incentives for pipeline construction.

In closing, your comments cite extensively an "opinion piece" of Vic Fischer and Jack Coghill from the July 19, 2006, Anchorage Daily News concerning their recollections of the meaning of the constitutional provisions regarding the surrender of the power of taxation. On July 31, 2006, the Attorney General of Alaska addressed these opinions. He began by noting a very fundamental legal point. The Alaska Supreme Court has made clear on repeated occasions that the "subsequent statements of a lawmaker about what a law was intended to do has no weight in a judicial proceeding." This makes common sense: today's recollection of what may have been intended nearly fifty years ago is fraught with the difficulties of the passage of time and the diminution of memory. Nor can the memories of two delegates reflect what others thought or intended. The opinion of Messrs. Fischer and Coghill emphasize that the Constitution requires tax exemptions to be temporary. The Constitution itself does not use the word temporary or state any time limitations on tax exemptions. According to the Attorney General, the Commissioner of Revenue has concluded "that the periods of fiscal certainty in the fiscal contract are not permanent and are reasonable in length given the size, cost and unique nature of the gas pipeline project." For further discussion, please refer to the Attorney General's letter and his opinion regarding the constitutionality of the fiscal term.

Very truly yours,

William A. Corbus

William A. Corbus
Commissioner

Enclosures

cc: Ms. Marty Rutherford
Mr. Richard LeFebvre
Mr. Mark Meyers
Mr. Bill Jeffress
Ms. Nancy Welch

Appendix I

This appendix addresses the comments of the former Department of Natural Resources (DNR) team from two perspectives. First, it compares the comments to the historical record of the positions that the signers of the former DNR team letter agreed to in the development of the joint State positions in the Producer negotiations or, in fact, negotiated in the discussions with TransCanada, all while employees of the State of Alaska. Second, it addresses the merits of the arguments advanced by the former DNR team, relying in a number of cases on answers that were a matter of public record before the former DNR team comments were filed but which the former DNR team comments ignore.

- **A retro-active "fix" of the Stranded Gas Development Act (SGDA) will result in an unfair advantage for the Producers over other applications**. This did not prove to be the case in practice. Marty Rutherford led negotiations with TransCanada based on its application of June 1, 2004, until the summer of 2005. These negotiations involved matters that went well beyond the confines of the SGDA. The former DNR negotiating team considered commitments on the part of the State of Alaska to make offers to purchase gas from Producers as well as extensive equity participation by the State in the pipeline. All of these are outside the purview of the SGDA in the view of the former DNR team. Therefore, Marty Rutherford must have led this negotiation on the assumption that a retro-active fix would be made to the SGDA in order to pass the TransCanada contract in the Legislature and that her conduct was lawful.

- **The contract does not guarantee a pipeline and work commitments are weak**. The former DNR negotiating team recommended to the Governor in mid 2005 to adopt the TransCanada term sheet as an alternative to the Producer fiscal contract and recommended to start papering a final contract with TransCanada. The former DNR negotiating team did not require the guarantee of a pipeline, nor did it provide for any work commitments after the first open season.

- **The project description is weak and could permit an over the top route**. The former DNR negotiating team did not provide a project description that was stronger, nor was there a procedure for preventing TransCanada from making work plan changes. What's more, the former DNR team supported the acceptance of the Producers' application, which included the project description, after a detailed discussion about the Northern Route. The Irwin team was satisfied in January 2004 that the application was applicable to the Highway Route.

- **The State cannot terminate the contract even if the Producers do nothing**. The former DNR negotiating team did not provide for the ability for the State to terminate the contract at all if after the open season TransCanada would proceed with the project in a manner that was not diligent.

- **The contract provides Producer benefits today while doing little to encourage a pipeline sooner rather than later. Any contract should include a construction**

deadline and penalties. The former DNR negotiating team provided for reduced pipeline taxes, but did not have any provisions for a construction deadline or penalties.

- **The contract provides too many financial incentives.** The most important incentive that is provided under the fiscal contract is the State risk sharing and participation of approximately 20%, which enhances the rate of return and net present value of the project. This concept was included in the October 29, 2004, opening proposal made by the State to the Producers. This proposal was formally endorsed by all departments in a meeting with the Governor prior to being proposed. This included the endorsements of the former DNR team. The DNR furthermore repeated its acceptance of such incentives in their letter of August 4, 2005, to the Governor outlining the "bottom line" position of the DNR.

- **Legislative consultants have shown the project to be highly profitable.** Legislative consultants suggested that the project would be profitable under conditions where an independent gas purchaser would buy all or most of the gas at the point of production on the North Slope. During the entire negotiating process, the DNR was specifically in charge of gas marketing matters. The former DNR team never presented to the Governor a credible independent buyer with ample financial strength who would be prepared to purchase large volumes of gas for favorable prices to the State and producers at the point of production. In fact the former DNR team specifically opposed undertaking early negotiations between the State and possible large buyers, such as Shell or British Gas, for long term contracts for all or most of the State's share of the gas. As a result, it is not possible for the legislative consultants to demonstrate that the project is profitable under the conditions they assume.

- **Under low prices the State gives away a significant share of the royalty and tax values.** The concept of providing incentives with respect to royalty and tax values under low prices was originally proposed by the former DNR team. The former DNR team insisted upon and specifically endorsed in the October 29 proposal a Price Differential Payment (PDP) based on a so-called S-curve. Under this concept, the State agreed to make significant payments to the Producers when Chicago well head prices would be less than $ 3.50 per MMBtu. The former DNR team repeated their suggestion of the S-curve in their August 4, 2005, letter to the Governor.

- **At any gas price the contract saddles the State proportionately with more costs and risk than the Producers.** The risk under the proposed fiscal contract is far less than the high, disproportionate risks the State would incur under the terms proposed by the former DNR team for a deal with TransCanada. Under the TransCanada term sheet conditions the State was to contribute a high percentage of the pre-open season development costs for the project without the ability to participate proportionately in the Alaska portion or Canadian portion of the line. Also the State would commit to a huge firm transportation (FT) commitment on the Canadian portion of the line without corresponding pipeline ownership. Furthermore, the term sheet proposed that the State make an extreme high risk price offer to the Producers for the purchase of a large volume of gas.

- **The State should not pay for <u>any</u> production and development costs**. As indicated above, the former DNR team itself had proposed a PDP on October 29, 2004, by which the State would pay for a share of production and development costs under low gas prices.

- **The State is forced under the contract to market its own gas**. As stated above, this was the risk sharing incentive that the former DNR team had specifically endorsed in front of the Governor as part of the October 29, 2004, proposal. Under the TransCanada contract the State would also be forced to market a far greater volume of gas.

- **The contract does not assure gas for Alaskans at reasonable rates and times**. The DNR's preference, as stated in the letter, to rely solely on the "superior" gas marketing of the Producers would certainly not result in gas for Alaskans, since the Producers prefer largely to sell their gas in Canada and the Lower 48 States.

- **The contract does nothing to assure reasonable transportation charges**. The fiscal contract does more to assure reasonable transportation charges than the term sheet that was negotiated by the former DNR team with TransCanada, which provided for favorable transportation charges for TransCanada. The fiscal contract with the Producers specifies that a separate open season will be held for gas shipped to in-state users and that in-state tariffs must not underwrite lower 48 transportation costs.

- **The contract could last for 45 years. This is very long.** The 35 year term from the commencement of commercial operations was endorsed by the former DNR team in the October 29, 2004, proposal.

- **The Production Tax is based on "profit" which is complex and will result in conflict with the Producers. It will also make the income of the State more uncertain**. In its letter about the "bottom line" of August 4, 2005, to the Governor the former DNR team specifically endorsed the Petroleum Production Tax (PPT) as then proposed, which was based at that time on a 20% tax and a 50% uplift (equivalent to a 10% tax credit). The PPT that was actually passed and signed by the Governor is more favorable to the State than the PPT endorsed in August 4, 2005, by the former DNR team.

- **The gas is not stranded**. As addressed above, the former DNR team endorsed the approval of the application of the Producers for an SGDA fiscal contract. The former DNR team also endorsed the application by TransCanada for a contract under the SGDA. Such approvals could not have been provided unless the former DNR team was of the view that the gas was stranded. The former DNR team led negotiations with the TransCanada team with respect to a contract under the SGDA well into the second half of 2005. Such negotiations would only be rational if the former DNR team also considered the gas to be stranded.

- **The State should not take its royalty and tax in kind**. The former DNR team recommended to the Governor that the State should take its royalty and tax in-kind in its endorsement of the October 29, 2004, proposal. The Governor relied on this

recommendation to approve the initial proposal to the Producers and in conducting the negotiations. The former DNR team specifically proposed taking the gas in-kind in its August 4, 2005, letter to the Governor.

- **If there is a dispute, under the contract Alaska cannot protect itself using its well-established judicial system but must resort to arbitration.** In its royalty settlement agreements (RSAs), the DNR has included arbitration, not court litigation, as the dispute resolution mechanism for royalty re-openers. The DNR has utilized the arbitration process quite successfully to date. It is also used in most international contracts.

STATE OF ALASKA

DEPARTMENT OF REVENUE

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October 18, 2006

Mr. Dick LeFebvre
1921 Sunrise Drive
Anchorage, AK 99508

Dear Mr. LeFebvre:

I want to acknowledge your comments of July 20, 2006, which we have reviewed as part of our process of receiving and digesting public comments. We note that your comments make the same points as the July 24, 2006, comments of Tom Irwin, Marty Rutherford and four other former Department of Natural Resources (DNR) officials. In fact the July 20, 2006, comments use language almost identical to the July 26, 2006, comments of the former DNR team and raise the same issues in the same sequence as those comments. You signed the July 26, 2006, comments as well as the July 20, 2006, comments. For these reasons, we have not drafted an independent response to your July 20, 2006, comments and refer you to today's answer to the July 26, 2006, comments which addresses the substantive points made in your comments. A copy is enclosed.

Very truly yours,

William A. Corbus

William A. Corbus
Commissioner

Enclosure

STATE OF ALASKA

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Senator Johnny Ellis
Senate Minority Leader
Juneau, AK 99801-1182

October 20, 2006

Representative Ethan Berkowitz
House Minority Leader
Juneau, AK 99801-1182

Dear Senator Ellis and Representative Berkowitz:

This is in response to your July 24 letter regarding comments on the proposed Alaska Stranded Gas Fiscal Contract and Preliminary Findings and Determination. The attachment addresses your bulleted concerns raised in your cover letter as well as those of your Gas Line Comments attachment.

Very truly yours,

William A. Corbus
Commissioner

CC: Senator Bettye Davis
Senator Donny Olson
Senator Hollis French
Senator Kim Elton
Representative Beth Kerttula
Representative Berta Gardiner
Representative David Guttenberg
Representative Eric Croft
Representative Harry Crawford
Representative Les Gara
Representative Max Gruenberg

SPECIFIC CONTRACT CONCERNS

ARTICLE 1: Definitions

1. Wrong Parties to the Contract

Recommendation: If the State enters into a contract with the subsidiary corporations, the corporate parent companies must also be signatories to the contract in order to protect the state's interest and ensure development of a gas pipeline.

Answer: Failure to perform under the fiscal contract would result in the loss of fiscal certainty for the sponsors' Alaska operation, a very significant penalty that promotes performance. As an additional backstop to implementation of the fiscal contract, the State has pursued a coordinating agreement to make sure that the obligations of the contract will be performed by the various LLC's and other ownership entities that will be established. Related to this is the issue of what is the appropriate corporate entity to sign the coordinating agreement. As a matter of corporate law, the proper question to ask is whether the parties to the contract have the capability to perform the commitments of the contract. The producers have argued consistently that their Alaskan affiliates have tens of billions of dollars of assets (including the value of their leases) in Alaska and those assets are more than sufficient to back up the obligations of the contract. The issue of a coordinating agreement will be resolved in the final LLC discussions.

2. Trust the Vote

Recommendation: Do not contract away the right of the people to enact law through initiatives or referendums. The people of Alaska must be free to make their own choice, and to exercise their democratic rights.

Answer: The specific complaint is that the effect of Article 11 will be to exempt the North Slope Producers from the proposed reserves tax if it is enacted. The incumbent Governor and all three candidates for Governor have rejected the notion that the reserves tax is an incentive to moving the project forward. Thus, the signers of the letter are at odds with the candidate of their party as well as the other candidates and the Governor. The fiscal contract does not restrict the voters' right to pass initiatives, but consistent with the concept of fiscal stability, provides the Producers with protection from any initiative directed at the project. The point is to protect the project and avoid litigation in a situation in which Alaska faces a huge revenue gap within a relatively short time if we have not shifted from a primarily oil based revenue stream to a primarily gas based revenue stream.

3. Too Broad a Definition of "Force Majeure"

Recommendation: Narrowly define "force majeure" to conform with generally accepted definitions.

Answer: The force majeure clause is carefully tailored to the circumstances of the Alaska gas pipeline project and is within standard commercial practice. The most important concern is whether the event was beyond the control of a party or not. The contract's definition requires that a *Force Majeure Event* be "beyond the reasonable control " of a party. Modern commercial practice with such clauses focuses on that issue, not foreseeability, and for that reason some large international project agreements of which we are aware omit any reference to foreseeability. The list of force majeure events is a reasonable standard list except that a specific diligence requirement has been added to the category of events that reference an inability to secure

permits.[1] That addition stiffens the standard. Another non-standard but stiffer element of the force majeure clause is that there is an initial period under the contract during which force majeure may not be invoked to suspend action under the contract. See Article 35.2(c).

ARTICLE 3: Effective Date and Term of Contract

Recommendation: Make the contract term as specific as possible. While different phase descriptions may be appropriate for different proposals, having phases spelled out better defines the term of the contract and how it will be implemented.

Answer: The discussion in your letter supporting this recommendation is directed not at the specificity of the term but to its duration. The Legislature enacted the SGDA and authorized a term as long as 35 years from the commencement of commercial operations, which could work out to a term of around 45 years. The commencement of commercial operations is likely to occur eight to ten years after the effective date of the fiscal contract. The May 24 2006, contract was negotiated within the term unanimously authorized by the Legislature in 2003. Your comments may be read as a disagreement with the Legislature about the terms of the SGDA. It is also consistent with the term of international agreements in which fiscal stability is provided. See PFIF at 115-117. Because of the huge cost and expected life of the project, the Producers have argued consistently that fiscal stability is needed to the full extent permitted by the SGDA and the term of the May 24 contract was consistent with the SGDA, comparable international agreements, and the producers' concerns.

[1] Your letter cites a statement of Daniel Johnston about the inclusion or not of bureaucratic delays in production sharing contracts. The fiscal contract is not a production sharing contract and the addition of the diligence standard to the force majeure definition further addresses the point implicitly made.

Nonetheless, because of widespread public concern about the term of the fiscal contract, including comment from the Legislature, the State is prepared to propose a shorter term of fiscal stability—of twenty five years from the commencement of commercial operations with a carve out of a different term and concept for fiscal stability for the provisions relating to the new PPT, SCIT and pipeline ad valorem taxes. For the PPT clause, the term would be divided into three periods with no fiscal stability provided up to the time of project sanction; with stability for fourteen years from project sanction but with the applicable taxes being frozen as of the later of the last day of the 2011 Legislative session or the FERC application date, and with a fiscal stability clause for the remaining balance of the time left from 25 years from the effective date. The contract provision for SCIT/PILT stability also would be trimmed back. The term of fiscal stability for payments in lieu of ad valorem taxes would expire on December 31, 2035 unless the State and the Participants agreed to extend it.

ARTICLE 4: Qualified Project Description

Recommendation: Provide a provision that, regardless of any changes to state or federal law, the pipeline route shall be as specified in the contract. Also, the state should have a meaningful role in accepting or rejecting proposed changes to the qualified project plan.

Answer: As you implicitly recognize, Section 103(d) of the Alaska Natural Gas Pipeline Act prohibits an over the top route. Section 4.1 of the fiscal contract identifies the route of the project as the southern route. A change in the project description referenced in Section 4.1 would require an amendment of the fiscal contract which cannot happen without the State's consent. To dispel any lingering concern, however, the State is proposed a contract amendment to make more explicit the fact that the fiscal contract is for a southern route project and to add a

provision that any change to the route presently described in the contract or core economic provisions would be subject to an opportunity for legislative review and disapproval.

The State will have a meaningful role in accepting or rejecting proposed changes to the qualified project plan for two reasons. First, the State's pipeline company will be a member of the LLC that will file the FERC application and build the LLC. As a member, it will have a twenty per cent vote on all aspects of the project as it develops, including changes in the plan. Second, at any time that the State itself believes changes in the project plan reflected in the annual update reflect a lack of diligence, it can seek relief under the special arbitration process in the work commitments clause.

ARTICLE 5: Work Commitments

Recommendation: Follow the lead of other nations' contracts and establish specific dates for completion of work commitments, with terms for extensions. Turn the burden of proof around so that if a deadline is not met, the pipeline sponsors must show why the deadline should be extended and the contract not terminated. Do not give up the right to take a dispute to the state courts. Impose meaningful penalty and damages provisions as deterrence to failing to proceed with construction of pipeline.

Answer: You do not give a specific example of a work commitment clause of another nation for a major energy project that contains better terms including specific dates. You also ignore the advice that both the State and the Legislature received from IPA, experts in large projects, that schedule-driven projects invariably encounter major cost overruns and other project obstacles. You also fail to acknowledge the fact that this is an international project, the overall progress of which is dependent on the interaction of two national governments and their

regulatory or permitting agencies and also of actions by State and provincial governments. The Preliminary Fiscal Interest Finding cites evidence that the work commitment clause of the fiscal contract is stronger than comparable large projects. See PFIF 128-29. As further explained there, there is not a single large multi-billion dollar international contract involving upstream and midstream elements that "guarantees a project" because a schedule-driven project will most certainly result in significant costs overruns. Such a schedule-driven construction project would increase economic risk to the owners and thus make actual construction of the gas pipeline less likely and more costly.

Moreover, the diligence standard of the work commitments clause will not be applied in a vacuum. Please refer to the new May 10, 2006, Project Summary, which is available on the Department of Revenue website, for a timeline and description of the sequence of project development activities.[2] In addition, there are additional points of reference *vis-à-vis* the FERC process for the open season (which includes timelines) and for the steps of the pre-filing process applicable to applications for certificates of public convenience and necessity[3]. Industry practice for large project is relevant as well. Thus, there are public and measurable points of reference for application of the diligence standard of the work commitments clause. The Administration was satisfied that the work commitments clause that was negotiated struck the right balance of enforceability and flexibility for this massive international project.

The suggestion is made that the right to take disputes to State courts should not be relinquished and there should be a scheme of penalty and damage provisions. The termination

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[2] The State is prepared to propose an amendment to the fiscal contract to incorporate the May 10 project summary in the work commitments clause.

[3] See the presentation of Daniel Ives, Lukens Energy Group, June 16, 2004, to the Legislative Audit and Budget Committee and Senate Resources Committee at 30-34. The sponsor group is committed to following the pre-filing process.

provisions of the work commitment clause provide a relatively speedy process compared to the court option. The history of royalty and tax litigation in the courts teaches that when the courts face issues of major consequence their process is deliberate, slow and costly. This is inconsistent with moving the project forward. Penalty and damage provisions are also inconsistent with the teaching of IPA and inevitably invite major litigation.

Because of widespread public comment on work commitments, the State is prepared to propose a letter of credit forfeiture provision whereby what is, in effect, its unspent balance would accrue to the State's benefit if project sanction does not occur by the fifth year after the effective date. In addition, the State is prepared to propose a failure to reach project sanction by that time would be a presumptive failure of diligence.

This approach is somewhat different than the May 24, 2006 fiscal contract and could lead to the difficulties that IPA has outlined. But the approach may be feasible and is worth exploring.

ARTICLE 6: Alaska Hire and Content

APPENDIX E: Alaska Hire and Content

Recommendation: More work should be done to determine how to achieve the greatest amount of Alaska hire possible. Including the requirement of a project labor agreement could help in this regard – not enough discussion has taken place on why this requirement is not in the contract. More work should be done to determine the optimal level of job training the state and corporations need to provide to ensure the highest number of trained Alaskans are ready for work when planning and construction begin. Very little evidence has been presented that the current provisions are adequate, or will lead to the optimal level of job training needed to ensure that as

many Alaskans as practicable are hired on this project and that prevailing wages will not be undercut.

Answer: The Alaska Department of Labor and Workforce Development and the Alaska Workforce Investment Board (AWIB) recognized the need for a comprehensive workforce development plan for the construction industry in preparation for the Alaska gas pipeline project. Last year, the AWIB adopted a comprehensive construction industry workforce development plan entitled "Building Alaska's Construction Workforce." The report can be found at the following web link: http://www.labor.state.ak.us/awib/forms/awib-construction.pdf. Significant strides have already been taken to meet the goals set out in that plan. Please see Section 3.5.1 of the Alaska Hire Provisions in the Summary of Public Comment report that was released on Friday, October 20, for a complete discussion of the funding and programs that will implement the Alaska hire clause and other related issues. The State is proposing a new article in the contract requiring the parties to commence negotiations of a project labor agreement, which, subject to legal restrictions, should include provisions promoting the hiring of Alaska residents and establishing hiring halls in rural and urban Alaskan communities. Additionally, the State is proposing an article in the contract requiring the parties to enter into negotiations with the Canadian government concerning a cross-border labor agreement. The objective of the PLA should be to ensure that every qualified, ready and available Alaska has an opportunity to work on the project. To this end the State will not commit to a union or non-union only agreement and expects that whatever terms are negotiated are the same for all workers.

ARTICLE 7: State Ownership

Recommendation: Before committing to state ownership in a gasline project, the proposal should be analyzed for its impact on the state's credit rating. An in-depth analysis should also be done to establish that the economic benefits of even a minority interest substantially outweigh the risks to the state and its citizens. The current state ownership proposal provides for risks that outweigh benefits.

Answer: Part of the reason the State considers Alaska's gas to be "stranded" is that even after we take our gas in-kind, and thus align the Producers gas ownership with the firm transportation commitments they must make, this project is in the lower quartile for internal rate of return in terms of each company's alternative development projects. Thus taking our gas in-kind is a core element of this contract. The risk to the State is taking the gas in-kind. Taking an ownership interest in the gas pipeline is a way to hedge that risk.

Over a considerable period of time, the Administration has analyzed the risks of State ownership of a share in the pipeline, including the impact on the State's credit rating. *See, e.g.*, PFIF at 206-207, 243-245, 189-202. The State has very experienced financial advisers who presented independent advice on this subject. PFIF at 206-207. Ownership of a share of the project diversifies the State's investments, offers a good return on its investment, and gives the State an opportunity to participate in and influence the development of the project and the policies and practices it chooses. In addition, the draft LLC agreement gives the State an opportunity at the time of project sanction to withdraw from the project and be paid back for the entirety of its investment if it does not want to continue as an investor in the project because, for example, it feels the risks to it are unwarranted.

ARTICLE 8: Regulation of and Access to Project Facilities and Disposal Services

Recommendation: Rather than ceding away RCA authority, seek ways to increase their involvement in order to protect the state's interest and ensure fair access to the pipeline. Heed the concerns raised by the legislative consultants on this subject, incorporated by reference. Review and consider recommendations in the 2001 Alaska Highway Natural Gas Policy council report.

Answer: This comment shows a misunderstanding of both the effect of the contractual provisions concerning the RCA and the exclusive jurisdiction of the federal government over the authorization and operation of interstate gas pipeline systems. The RCA is not bound by the contract; it is excluded from the definition of State in the definitional provisions of the contract. Whatever jurisdiction the RCA might hypothetically have over some element of the contract is not modified or "ceded away." All who testified supported FERC jurisdiction over the product: Article 8 commits the parties to the contract to seeking and supporting such jurisdiction.

Federal regulation of interstate gas and oil pipelines is far different in scope. FERC does not authorize or control the construction or operation of interstate oil pipelines; it only regulates the rates for interstate oil movements. For oil pipelines, therefore, there is dual jurisdiction—the FERC sets interstate rates and the RCA sets intrastate rates. In those circumstances, a "joint board" is appropriate. Over interstate gas pipelines, it has long been established that the FERC has exclusive jurisdiction and the RCA or other State commission does not have authority to set the rates for natural gas that travels on such gas pipelines even if the gas stays within Alaska. Both rates are set by the FERC. See PFIF at.137-138. *California v. LoVaca Gathering Co.*, 379 US 366 (1965).. FERC also controls the terms of access. As

required by the Alaska Natural Gas Pipeline Act of 2004, the FERC has adopted an extensive set of open season regulations that control and ensure fair and equal access to an Alaska gas pipeline. The State cannot establish its own terms of access without conflicting with federal law. Any effort to do so would fail under the Supremacy Clause of the United States Constitution.

The Administration, working with the RCA, succeeded in obtaining provisions in ANGPA that (1) require the FERC to consult with the State about rates or rate settlements, and (2) confirm RCA jurisdiction over the rates and terms of an in-state lateral from the mainline. A right of way based fair access clause to attend to control access to an interstate gas pipeline would conflict with and be preempted by federal law.

You assert that "an independent pipeline company has far more incentive to maximize access both prior to construction and over the life of the project than the corporations." (sic) It is unclear what you mean by this. Whatever the ownership of the pipeline, access to an Alaska gas pipeline is controlled by the same set of special FERC rules. The incentive for all pipelines is to fill their pipe to capacity and not to have excess capacity because the cost of excess capacity is charged to the pipeline owners per FERC policy. If you are using access as short hand for expansion, we believe that Congress and the FERC have adopted expansion friendly requirements that apply regardless of ownership,[4] including FERC's new power to order expansion of this pipeline if a shipper petitions. The incentive that you assert is based on the view that a producer owned pipeline will forego profitable revenue, allegedly to protect its producing affiliates. This does not withstand economic analysis. See the answer to Specific

[4] The Administration negotiated a State initiated expansion to add to the array of expansion options. Some potential independent shippers objected to its term, indicating they would prefer to rely on either a voluntary expansion or the FERC's new mandatory expansion powers.

Contract Concerns, Anti-Trust Issues and Alternatives to a Producer Owned Gas Line at the end of this attachment. It also could violate FERC policies and regulations.

ARTICLE 9: In-State Markets

Recommendation: In conformance with the stranded gas act and in keeping with other nations' production sharing contracts, any fiscal contract should include a provision that ensures gas will be available for in-state use at a price that is fair to all parties, and that recognizes the state's interest, as a sovereign, to provide for local power needs. All Alaskans deserve to have affordable energy – access to the gasline would help many Alaska communities that are currently struggling under the burden of high fuel prices.

Answer: How gas will be provided to in-state users is a policy choice for the State as it markets the large amount of gas it will have under the fiscal contract. It is not a proper subject for a fiscal contract with the producers that is intended to provide a fiscal foundation for the gas that will advance the project. How the State sells its gas is not a matter for negotiation with the Producers and is not a proper subject for the fiscal contract.

The State will own approximately 20% of the gas, approximately 1 bcf per day, which is far more than any reasonable projection of likely in-state needs. Thus, the State will be in a position to provide gas to satisfy in-state needs and the Administration is announcing a policy to provide for those needs. A future administration will decide the precise terms, including the price, for sales of the State's own gas to in-state users consistent with the requirements of the Alaska Constitution about obtaining maximum value for the disposition of the State's resources. Given the large amount of gas that the State will control, the favorable FERC rulings on in-state rates, and the fiscal control provisions for off-take points and

interconnection, it would be superfluous and potentially costly for the State to negotiate a requirement for the Producers to supply gas at a predetermined price for in-state use. In addition, it should be kept in mind that the Producers may choose to sell gas for in-state users if any of them wishes.

ARTICLE 11: Fiscal Stability

EXHIBIT G: Amounts Payable to Political Subdivisions and State

Recommendation: The provisions that prevent future legislatures and voters from modifying or fixing problems in our oil and gas tax laws when the need for changes becomes evident, should be deleted. Locking in a tax rate that vastly shortchanges Alaskans is poor policy, and might render a contract unenforceable.

Answer: The Attorney General of Alaska has issued a formal opinion addressing the constitutional issues regarding the tax exemptions and fiscal stability provisions of the contract. As you recognize, it is to be expected that the Alaska Supreme Court will settle these issues. You cite the negative opinion of two former delegates to the constitutional convention, but the law is well established that the views of a few constitutional convention delegates nearly five decades after the fact are entitled to no legal weight. *See* July 31, 2006, Opinion of Attorney General David Marquez.

Since taxes are a fundamental economic "cost" to the sponsors of a project, the ultimate logic of your position is to not grant fiscal stability against tax changes which amounts to not granting fiscal stability to the project. How does that serve to advance the project? Fiscal stability, *i.e.*, knowing what their taxes will be over the term of the Contract, is a core element of a contract.

As discussed above, the Administration is prepared to propose amendments which both delay and shorten the locked-in period for the provisions that incorporate the new PPT legislation. Nonetheless, if the Legislature truly intended to provide fiscal stability for a gas project, then it must necessarily deal with the economic cost to the project of major tax provisions.

ARTICLE 12: Royalty Payments

Recommendation: Any provision regarding royalty gas should be negotiated so that at a minimum it meets the limitations imposed by the stranded gas act as it was enacted in 1998. The state should not concede to pay field costs or take responsibility for disposal of impurities in contradiction of most lease terms.

There are other options as well. In addition to the 1998 commercialization team's suggestion that the state take its royalty gas in-value, the 2001 Natural Gas Policy council provides several recommendations, including adopting a mixed portfolio of in-value and in-kind sales and enforcing the "higher of" clauses on natural gas royalty.[5]

More recently, Jim Eason, a legislative consultant, has suggested that the point of in-kind taking could be shifted from as far upstream as possible (and thus putting additional costs on the state), to a point as far downstream as possible. He suggests the AECO Hub in Alberta. Eason states,

The Participants would still have the certainty of the State's royalty and tax gas being available for whatever term is appropriate. The State would still be

[5] Council Report, page 39.

responsible for paying for the transportation of its share of costs in moving its gas to Alberta. It would not, however, have the increased risk and exposure that flows from the capacity management responsibilities of the current proposal, nor would it need an expanded bureaucracy and a host of consultants through the term of the ASGFC to manage the capacity of its royalty and tax gas sales.[6]

Eason also suggests that the state could make a commitment to leave its gas in-value for the same term as is currently proposed.

Answer: The proposed Contract does not negotiate away the State's right to receive royalty. In fact, what the Contract does is retain the state's full royalty share - and administration economies have demonstrated that the proposed contract retains the full value of that royalty share, after payments and costs under the contract are accounted for. What the Contract also does is provide the State with the best opportunity available to us to get a pipeline built as soon as possible, and as the best total cost possible.

The fact is that gas pipeline transportation is regulated by federal contract carriage regulations – not common carrier regulations. Because of this, the effect of gas pipeline regulations is very different from the affect of oil pipeline regulations, and our TAPS experience.

No major gas pipeline project is going to be built without long-term fixed financial commitments. The makers of those financial commitments will demand fixed shipping commitments to underwrite the financing of the pipeline construction. Those fixed shipping commitments coupled with the federal gas contract carriage regulations (in both the US and

[6] Memorandum, Jim Eason to Senator Therriault, June 3, 2006. Eason notes that this alternative would not address the reasonableness of other royalty-related changes that have been proposed.

Canada) effectively eliminate the opportunity to switch between taking royalty in-value and royalty in-kind.

The fact is that, despite our lease language, the opinions of the 2001 policy council and the 1998 commercialization team, and the advice given by the legislature's pipeline experts, under both United States and Canadian federal gas pipeline regulations, the State has no practical way to enjoy the benefits of royalty switching. The Legislature's pipeline consultants should have known that and they should have provided you with this information. The Administration negotiating team's acceptance of giving up royalty switching was largely an acknowledgement that federal gas pipeline regulations trump any rights provided by State leases or contracts. What we get in return is the best opportunity available to us to get a pipeline built as soon as possible, and as the best total cost possible.

The Administration also chose to take royalty in-kind over royalty in-value for several reasons. First taking royalty in-kind eliminates valuation battles with the Producers. This one area is the largest area of litigation between the State and Producers on the oil side and, if royalty gas was received in value, would be expected to become at least as contentious and costly on the gas side. This litigation cost of valuation issues is a major cost category which is eliminated by taking our gas in-kind. Second, although marketing of our own gas places a new cost burden upon the State and places us in competition with the Producer-marketers, taking our gas in-kind and doing our own marketing allows us to manage market risks in a manner which is to the best benefit to the State. It also gives the State greater control over use of gas for in-state needs and for development of in-state industries. Contract terms were also obtained which ensure a 'level playing field' for the State with respect to Producer information which will be relevant to effectively marketing our gas. Finally, to be conservative, an extremely heavy cost burden for

developing and running a marketing organization was included in the analysis of the project's economics.

It is critical to remember that the Administration included all of these various costs related to contract terms in the economics, and did not include likely cost benefits such as reduced litigation and the ability to add value with a marketing organization. Nevertheless, economics show that, under the proposed contract, the State retains the royalty and tax value calculated in the assumed status quo world – plus we obtain our best opportunity to get a pipeline built as soon as possible and at reasonable cost.

ARTICLE 13: Tax Bearing Gas Payment

Recommendation: In the context of the proposed contract, the state should not contract away its right to impose a natural gas production tax, nor should it assume the costs of selling, marketing and transporting the gas.

Answer: As noted above, there is an inherent conflict between the idea that fiscal certainty on economic fundamentals is beneficial to advancing the project and the idea that the State should be free to change one of those economic fundamentals at any time it chooses to in the future. In the last legislative session and after two special sessions the State enacted a comprehensive revision of the production tax. Locking in that modern production tax law in order to provide fiscal stability to the sponsors of the project is a reasonable policy choice.

Nonetheless, because the new law provides that the legislature may take another look at the law by 2011, the State is prepared to propose legislative amendments that would defer the start of fiscal stability on the PPT related provisions until the completion of the legislative session in 2011 or the FERC application date, whichever is later, and is also prepared to shorten

the proposed period of fiscal stability. It is not prepared to dispense with the concept of fiscal stability with respect to the PPT as you appear to suggest.

You object also to the State assuming the costs of selling, marketing and transporting the gas. The PFIF, in Sections 6.3.1, 6.3.2 and 8.2.3.4, provides extended discussions of market risks and the options available to the State to market our gas. By taking its gas directly and assuming the responsibility for marketing it, the State reduces the risk and advances the prospect for the project. Once the State takes responsibility for the sale of its gas, it must necessarily make arrangements either directly or through an agent for the marketing and transportation of its gas. It should be note that an advantage of this is that the State will not receive its value derivatively from how the producers market their gas, thereby avoiding years of costly litigation over whether their marketing efforts produced the right "value" for State owned gas.

Finally, your comments pessimistically assume that the State cannot manage the marketing of its natural resources. Today the State takes about half of its royalty oil in kind and markets it to oil refineries located in-state. If the same assumption had been applied to the Permanent Fund, its only investments would be bank savings accounts or government bonds. In fact, the Permanent Fund has used professional advisers to invested in a diversified portfolio of assets with very successful long-term results. The State has the same opportunity to successfully manage its gas assets.

ARTICLE 14: Payment in Lieu of Production Taxes

EXHBITS P, O, R, X, and Y

Recommendation: The legislature should not agree to the proposed amendments to the stranded gas act or the administration's proposed tax changes; nor should the administration include changes to the oil tax structure as part of the gasline contract.

Answer: The Legislature has enacted into law a major restructuring of the petroleum production tax consistent with the proposals of the administration. Any objections to it passage are therefore moot. We agree that the legislature should carefully consider the fiscal contract and related documents that have been presented to it. We believe the Legislature should enact the package of amendments that is necessary to carry forward the fiscal contract and thereby advance the Alaska natural gas pipeline project. Because Alaska simply must transition to a gas based economy by 2016 as oil production continues its decline, and because a gas pipeline project will take eight to ten years to come to fruition, and because the markets for Alaska natural gas may erode in favor of other supplies, there is not much time to get a contract authorized and executed. The greatest risk to Alaska is not a producer owned project but not getting a gas line at all. See Letter of Commissioner William Corbus to Senator Thomas H. Wagoner, September 27, 2006, at 5.

Whether to give fiscal stability for oil as well as gas was fiercely and repeatedly argued during the fiscal contract negotiations. At first the State refused to consider fiscal stability for both oil and gas. As part of the process that led to the contract, however, the Administration concluded that this presented an opportunity to achieve a much needed revision and modernization of Alaska's production tax with a considerable increase on the taxes that the

producers would pay. In light of that, the Administration determine that it was reasonable to grant fiscal certainty to oil as well as gas so as to secure broadly fiscal stability for all the State factors that might influence the major economics of the project.

ARTICLE 22: Payment of Fiscal Obligations

Recommendation: All provisions regarding state fiscal obligations should be revisited to limit the state's liability as much as possible. The option for the corporations to recoup or offset an amount due from the state with royalty or tax gas taken in-kind should not be permitted.

Answer: As previously stated, taking the State gas in-kind is a core element of the Contract, *i.e.*, unless we do so there will be no gas pipeline. By taking royalty gas in kind and taking tax payments in gas, the State will assume responsibility for the successful commercial marketing of its gas. In that context, the State will have to act responsibly in the payment of the standard commercial obligations it incurs, including some payments related to production, processing and shipping costs. The provisions referenced have been developed as reasonable ways for the State to satisfy obligations related to the State's new commercial responsibilities.

ARTICLE 23: Point Thomson

Recommendation: Maintain state control over development of Point Thomson. It is worth investigating whether other developers are interested in the lease tracts and whether development would occur faster than relying on the current leaseholders.

Answer: First, let us provide you with an update on the status of the Point Thomson Unit:

Historically, continuance of the PTU and its leases has, until the latter half of 2005, been with the concurrence of commissioners of natural resources of several administrations of varied political perspectives. The companies have invested significant amounts of money over several decades in exploring this acreage and in addressing major technical issues. In recognition of those facts, each of these administrations has been a party to extending these leasehold interests.

Under the amended DNR decision of October 27, 2005 the PTU Agreement was declared in default. That decision did not call for the return of the PTU leases to the state, but it did call for "a plan to bring the PTU into commercial production within a reasonable time frame" and provided dates for initiation of development operations, commencement of drilling, and commencement of production. Since those deliberations have now ended, the companies are back to dealing directly with DNR to develop an acceptable POD which will lead to field development.

On September 8, 2006, the Commissioner of the Department of Natural Resources issued a final extension of time to submit a cure to the October 27, 2005 decision placing the unit in default. That cure, with all supporting documentation, was required to be submitted to DNR no later than October 20, 2006. In addition, any party wishing to submit an appeal on the subject must submit all appeal documentation to the DNR offices by November 3, 2006. The commissioner of natural resources will hold an appeal hearing on November 13, 2006. Any decision concerning the cure and any appeals will be made by the commissioner of natural resources subsequent to the November 13 hearing.

To respond to your concern:

The PTU reserves and gas deliveries will play an integral part in the proposed gas pipeline project. The contract provisions concerning PTU provide a specific context for its development. The contract provides for a PTU development schedule which is consistent with and which supports development of the mainline.

Without a gas pipeline much of the vast amount of value to the state represented by PTU will never be realized. The contract is based on setting the conditions necessary to get a gas pipeline built. Without a gas pipeline the only value to the state resides in the portion of the liquids produced from the reservoir which can be transported to market through TAPS, or which can otherwise be used on the North Slope. TAPS can transport only a limited portion of the lighter liquids due to vapor pressure concerns in the pipeline and downstream. This being the case any statements made to the effect of value lost or received must take into consideration what conditions are necessary to get a gas pipeline built, the limitations of the existing oil infrastructure as it affects PTU liquids development, the investments (in which the state will share under the PPT) required to overcome those limitations, and the highly challenging technical demands and uncertainties associated with developing the Thomson Sand Reservoir in a save and environmentally sound manner.

The contract imposes specific requirements upon the producers with respect to development of the PTU:

- Each producer must commit PTU gas reserves to the project; and
- The producers must apply to the AOGCC within 6 months for issuance of pool rules.
- The contract requirement that the gas pipeline project be pursued "with diligence" applies to PTU development, as well as the rest of the mainline.

If any of the above requirements is not met, or if the contract is terminated for any reason the producers' rights to Point Thomson expansion leases terminate unless they initiate alternative development of the PTU within one year of the contract termination. In addition, DNR can also pursue other steps, including termination of the unit, and initiating procedures to revoke the leases.

Finally, nine months after startup of the mainline, obligations to DNR Plans of Development resume which will allow DNR to maintain to management oversight of PTU oil and gas development.

You also suggest investigating whether other developers are interested in the least tracts and whether development would occur faster than relying on the current lease holders. This is certainly worth consideration in the current circumstance, and was undoubtedly a consideration as prior directors and commissioners approved plans of development for PTU. Certainly other developers would be interested in these tracts. Just as certainly, the bulk of definitive information about Point Thomson is confidential, held only by the current lease holders and the Division of Oil and Gas' Resource Evaluation group. Even once the data was made available to a new entity, a significant amount of time would be needed for that new entity to "get their arms around the problem." The technical and economic challenges to PTU development raised by the current leaseholders are certainly better understood by them, than by any other entity. In addition, that set of major leaseholders represent some of the most technically competent companies in the world – a group in many ways, best able to conquer the technical and economic challenges of PTU as quickly as any entity or group of entities in the world. In fact, these companies have already spent an enormous amount of money attempting to monetize Point Thomson, as well as Alaska's other ANS gas resources. On the other hand, these

same companies have held for many years leasehold commitments to the state, which the state has continued to protect via unitization. Those leasehold commitments exist via contract, and the state has the right to enforce our lease contract rights with these as well as any other leaseholders, in order to maximize the value of the state's assets for all Alaskans.

ARTICLE 26: Mandatory Dispute Resolution

Recommendation: Maintain the option of dispute resolution, but continue the ability of the state to settle disputes through the court system, under established legal rules.

Answer: Arbitration to resolve disputes is widely employed in both domestic and international contracts. It also has been included in all of the State's royalty settlement agreements as preferable to litigation and the State has achieved success in the case where it has been used. One reason favoring the choice of arbitration is that disputes over royalty valuation and taxes have taken decades to resolve at great cost and without a finally litigated result in any major case. Because the State is taking royalty gas in kind and tax payments in gas and marketing the gas itself, there simply should not be the type of costly, long duration, large scale valuation disputes that arose when the value of the State's royalty oil and tax payments was derivative of the amount for which the Producers said they sold it. Leaving dispute resolution as an option would add an element of uncertainty to the contract and could lead to gaming in the choice of what means would apply to any given dispute.

ARTICLE 28: Administrative Termination

Recommendation: The administrative termination provisions should comply with the requirements of the stranded gas act.

Answer: The contract reshapes the administrative termination provisions consistent with the separate termination remedies provided in the work commitments clause and the overall dispute resolution provisions. The revisions avoid overlapping termination remedies. It was neither illegal nor improper for the Administration to negotiate a contract that contemplated legislative changes to the Stranded Gas Act.[7]

ARTICLE 35: Force Majeure

Recommendation: As discussed under Article 1, narrowly define "force majeure." Also, make provision for continued payment of fiscal obligations to the state during force majeure events.

Answer: Your concerns regarding the scope of the "force majeure" clause have been fully answered in the discussion of the same point in Article 1 above. You suggest also that the payments of fiscal obligations should continue during periods of force majeure. If oil or gas flows are interrupted, the related fiscal obligations are suspended proportionately. That is entirely logical and what happens in fact. If less oil or gas flows, less oil or gas is sold and the amount of SCIT or PPT related income is reduced accordingly. Generally speaking, the State cannot tax income or receive payments in lieu of taxes on income that does not exist as your comments would suggest. Impact payment may also be suspended but cannot be suspended until one year after a force majeure notice. *See* Article 18.3.

[7] See the letter of Attorney General David Marquez to former Commissioner of Natural Resources Tom Irwin, October 27, 2005.

ARTICLE 40: Representations and Warranties

Recommendation: As discussed under the definition section, the parent corporations must also be signatories to a contract along with the subsidiary corporations in order to guarantee the contract provisions will be fulfilled.

Answer: This is a repetition of a point made and answered earlier.

ARTICLE 41: Relationship to Law and Other Agreements

Recommendation: The state should not cede its sovereign authority to regulate corporate activities on the gas pipeline project.

Answer: The intent of Article 41.2 is to clarify the relationship between provisions of the contract and other agreements, leases, regulations, rules and other legal documents. Article 41.2 directs the parties down a path towards reconciling the contract and prior legal arrangements but in the event reconciliation is not reached, says that the contract provisions govern between the parties. This is no more a surrender of sovereign power than in any other case where the State revises a regulation, order or rule after industry input or revises a lease or contract by agreement with the other party to the contract. Also, for the contract to become effective, the legislature will have authorized this provision as well.

OTHER ISSUES:

INDEMNIFICATION PROVISIONS

Recommendation: If indemnification is provided, a contract's indemnification provisions should comport with the policies set out in the Attorney General's Opinion #661-05-0132. Indemnification should not be used to undermine the voter's right to adopt an initiative.

Answer: The Attorney General has reviewed the contract's indemnification provisions and has concluded that they comply with the policies set out in prior opinions on this subject. Amendments will be proposed that confirm that payment of any indemnification award is dependent on legislative appropriation and cannot be separately enforced in court as these opinions require. The concerns about the Reserve Tax were addressed in answer to Article I above.

ANTI-TRUST ISSUES

Recommendation: An independent pipeline is the preferred option form a competitive perspective. If the state does decide to go forward with the producer-owned pipeline, there have been several suggestions put forward by the legislative consultants including a partial divesture to an independent pipeline, or establishment of an independent system operator, with the power to require expansions and creation of an independent market monitor. A producer-owned pipeline brings the need for contract terms that would safeguard against anti-competitive behavior by the producers.

Answer: The assertion that competitive concerns favor an independent pipeline is unproven. You suggest that a producer owned pipeline would have the ability to raise rates to supra

competitive levels. This statement ignores the fact that the same regulatory requirements apply to setting rates for a pipeline whatever its ownership. Research provided to the Legislative Budget and Audit Committee and Senate Resource Committee on June 14, 2004, Gas Pipeline Restructuring at the Federal Energy Regulatory Commission by Morrison & Foerster shows the difference between producer owned and independently owned pipelines. See the same at 27-29. Further, from a theoretical standpoint, an independent pipeline has only one objective--to seek to maximize its rates--because that produces the most profit. A pipeline with affiliated shippers has conflicting incentives because higher tariffs reduce the profit from the affiliated gas sales.[8] These differing incentives put pressure on the producer owned pipeline to keep rates down. Thus, your description of the consequences of producer ownership is exactly backwards.

Your preference for an independent pipeline flies in the face of reality. President Carter made a decision in 1979 that excluded North Slope producers from ownership and failed in his effort to realize a gas pipeline. Indeed, the federal government had to retreat from that decision because the equity participation of the producers was needed to finance the project. Today, the commitment of the producers to FT agreements that financially underpin any pipeline are needed for any project because, after all is said and done, they have the lease rights to more than ninety per cent of the known gas. The fastest way to secure a pipeline is to reach agreement with them. Your preference for an independent pipeline, or for a new solicitation for an independent pipeline, must face the hard reality that the producers have the gas and they prefer to ship their gas on a pipeline that they own. Any other project must devise a scheme for taking the gas away from the Producers and that is a recipe for litigation and delay, and ultimately for

[8] One exception to this might be cases like TAPS where higher rates serve to lower taxes and royalties. But the exception does not apply here because the State is taking its royalty in kind and also receiving tax payments in gas

failure. Indeed, in a letter to Governor Murkowski dated July 13, 2006, TransCanada Chief Executive officer, Hal Kvisle, said:

> ". . . TransCanada has consistently advised your Administration to be wary of independent pipeline proposals that would seek to develop a pipeline without the agreement and support of the ANS producers."

Both the analysis and the remedies suggested by the legislative consultants on antitrust issues are flawed. These issues are fully addressed in, and we refer you to, the legal memoranda of Morrison and Foerster on antitrust issues that were attached to the PFIF and the more recent October 19, 2006 Memorandum of Morrison and Foerster "Alaska Natural Gas Pipeline - Producer Owned Pipeline Project" as well in presentations on "basin control" and related issues during the legislative hearings. For example, the FERC has never required a natural gas pipeline to transfer control of its facilities to an independent operator, a point that Greenberg Traurig concedes. Nor does the Greenberg Traurig memo explain why such a radical remedy is either necessary or desirable, or and why conventional regulation, e.g., the open season and affiliate rules, is insufficient to keep the Producer-owners' conduct under control. Greenberg Traurig suggestion of a partial divestiture is also unjustified and unprecedented. Their memo fails to cite any case in the entire energy sector to support their contention that the FTC would act in such a manner. Nor is it likely that the FERC would conclude that the regulatory structure it has used to ensure access to gas pipelines in the lower 48, let alone the more detailed requirements applicable in Alaska, would fail to protect shippers on the gas pipeline.

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and directly marketing the combined royalty and tax gas. As a consequence, there are no royalty or tax "savings" for the producers by attempting to keep rates high.

There has been exhaustive testimony by FERC representatives and by the State's counsel and others about the array of tools that FERC has to control anticompetitive behavior, including its recent open season regulations, its anti-affiliate preference requirements, its non-discrimination policies and the new sanctions it was given by the Energy Policy Act of 2005, which include penalties of up to $1 million a day for violations of its regulations and orders. Overbroad statements about a producer owned pipeline's ability to take actions that are counter to these policies ignore the careful presentations that have addressed the legal remedies and constraints that are applicable.

ALTERNATIVES TO A PRODUCER-OWNED GASLINE

Recommendation: As part of the public and legislative review, the administration should prepare a comparative analysis of the proposed contract with other qualified proposals, and present negotiated proposals from independent pipeline operators to the legislature for a vote.

Answer: The Preliminary Fiscal Interest Finding presented a comparison of the proposed contract with the LNG option and the Y-line option. See PFIF at 179-183. As for qualified projects, the Port Authority proposal is not a qualified project under the SGDA. It failed to complete the process required to qualify. See PFIF at 184. Mid-American Energy Holdings and its affiliate withdrew its application under the SGDA and they therefore do not have a qualified project. See PFIF at 188. Trans-Canada did qualify under the SGDA process, see PFIF at 186, but by letter of July 13 supported a producer project within the context of the fiscal contract as the right approach to an Alaska gas pipeline. It should be noted that today only a producer sponsored project presents the complete package needed for an Alaska gas pipeline. This is a result of the reality that the producers have lease rights to the known gas reserves that underpin

the project. Other pipeline proposals may be advanced but none can be complete without access to, and the support of, the producers as owners of the gas.[9]

[9] The wisdom of completing negotiations for other proposals, by definition incomplete, is debatable. It also would call for deployment of costly resources by both the State and sponsors of other projects.

MEMORANDUM

TO: State of Alaska COPIES: Robert H. Loeffler

FROM: Bradley S. Lui
Roger W. Fones
Jeny M. Marcinko[1]

DATE: October 20, 2006 FILE: 08083/93

RE: Alaska Natural Gas Pipeline - Producer Owned Pipeline Project

This memo addresses arguments raised in an April 22, 2006 memorandum from Kenneth M. Minesinger and Cecil Chung of the Greenberg Traurig law firm to Senator Therriault, Representative Samuels and others ("Greenberg Traurig" or "Memo"). The Memo is entitled "Competitive Analysis of Producer-Owned Alaska Natural Gas Pipeline," and argues that potential competitive issues might arise if the three largest owners of the proven natural gas reserves on the North Slope, *i.e.* BP, ConocoPhillips, and ExxonMobil (individually, a "Producer" and collectively, the "Producers") were to build, own and operate a pipeline to transport natural gas from the North Slope to Canada and ultimately to the lower 48 states (the "Gas Pipeline"). The Memo contends that (1) in 1977, the U.S. Attorney General identified potential competitive concerns with Producer ownership of a Gas Pipeline; (2) the risks presented by these competitive issues continue to exist today, and (3) consideration of these issues will cause significant delays in any proceedings regarding whether to approve a Producer-owned Gas Pipeline.

Contrary to conclusions reached by Greenberg Traurig, Producer ownership of the Gas Pipeline does not raise significant competitive concerns. As the Memo acknowledges, joint ownership by the Producers does not by its nature violate the antitrust laws. Moreover, because the Producer-owners lack downstream market power, a Producer-owned pipeline has no incentive to discriminate against third party shippers. Even if the Producers did possess downstream market power, the requirements of the Alaska Natural Gas Pipeline Act as well as the FERC regulations implementing that Act provide sufficient safeguards to prevent the Producers from operating the pipeline in an anticompetitive manner. Under these conditions, Producer joint ownership does not create significant antitrust issues.

I. Producer Ownership of the Gas Pipeline Would Not Violate the Antitrust Laws

A. Producer Ownership Will Not Reduce Existing or Potential Competition Among the Owners

[1] Brad Lui and Roger Fones are partners, and Jeny Marcinko is an associate, in the antitrust practice group of Morrison and Foerster. Mr. Fones was Chief of the Transportation, Energy & Agriculture Section of the Antitrust Division from 1993-2005. Mr.Lui was a trial attorney in the Antitrust Division before joining Morrison and Foerster.

Under Section 7 of the Clayton Act, 15 U.S.C. § 18 and Section 1 of the Sherman Act, 15 U.S.C. § 1, the formation of a joint venture is unlawful only if the effect of the transaction is to lessen competition substantially in one or more relevant markets. This analysis is performed by evaluating the markets in which the parties compete, their market shares, and the likelihood that their collaboration would lessen competition in those markets.[2]

Under the legal standards of the Clayton and Sherman Acts, a Producer-owned pipeline is not likely to reduce competition substantially in any relevant market.[3] A Producer-owned pipeline would only increase competition in the market for transportation of natural gas because none of the North Slope's gas reserves are currently being transported to consumers in the lower 48 states. The increase in the overall supply of gas into the lower 48 will increase – not decrease – the level of competition for the downstream sale of gas above what existed *ex ante*. Likewise, there would be no reduction in competition in the exploration and production of North Slope gas. Indeed, incentives for competition in the exploration and production of North Slope gas should be enhanced since the product of that exploration and production will be able to reach consumers in the lower 48 States. For these reasons, the formation of the joint venture by the Producers to build and operate the Gas Pipeline would not violate the antitrust laws.[4]

B. Producer Ownership Will Not Lead to Lessened Competition, Higher Tariffs, or Reduced Throughput in the Transportation of North Slope Natural Gas, as Compared to an Independent Pipeline.

Any natural gas pipeline for North Slope gas must be authorized by the FERC pursuant to the Alaska Natural Gas Pipeline Act (the "Gas Pipeline Act"). As Greenberg Traurig acknowledges, there will be only one Gas Pipeline built.[5] Thus, regardless of ownership, the Gas Pipeline will have a monopoly over transportation from the North Slope. Accordingly, the Gas Pipeline's tariffs, capacity, and access will all be regulated by FERC, which will protect non-affiliated shippers against unreasonably high tariffs and limited access.

II. A Producer-Owned Pipeline Is Unlikely to Impose Anticompetitive Vertical Restraints

A. Vertical Integration Is Not Inherently Suspect Under the Antitrust Laws.

The Greenberg Traurig Memo correctly notes (at 8) that most vertical mergers do not raise competitive concerns. The Memo also implicitly acknowledges that the Producers' proposal is not a merger, but nevertheless proceeds with a discussion based on the following premise: "[T]he Alaska pipeline had already been built and then acquired" by the Producers.

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[2] A more detailed explanation of the three-step analysis involved in evaluating the lawfulness of the joint venture is contained in the previous memorandum from Morrison & Foerster to the State of Alaska, dated March 11, 2005.

[3] The bases for these conclusions are discussed in detail in the March 11, 2005 Morrison & Foerster memorandum on page 5.

[4] The Greenberg Traurig Memo concedes this point on page 6 ("the formation of the joint venture would generally be lawful").

[5] It is extremely unlikely that any of the individual Producers would be in the position to build its own pipeline (separate from the proposed pipeline). Therefore, the fact that the Producers are collaborating in building the pipeline does not reduce potential competition in the transportation of gas from the North Slope.

The Memo then embarks on a lengthy discussion of vertical merger precedents at FTC, DOJ and FERC. This merger discussion is largely irrelevant because it fails to analyze the situation at hand: A proposal to vertically integrate by internal expansion (new construction). We are aware of no challenges by any competition agency to a proposal to vertically integrate by internal expansion, and the Memo cites none.[6] It is clear that there could be no antitrust challenge to the construction of a Producer-owned pipeline because there is no existing competition to be reduced – there is, as yet, no pipeline. Even if it were proper legal analysis to hypothesize an existing pipeline and subsequent acquisition by the Producers, no significant competition concerns would be presented, as explained below.

B. A Producer-Owned Pipeline Would Not Have Significant Incentives to Act in an Anticompetitive Manner Towards Third Party Shippers.

Greenberg Traurig alleges that the Producers would have the incentive to use the pipeline in anticompetitive ways in order to discriminate against rival third party shippers. This argument is necessarily based on the premise that the Producers have market power over natural gas prices in the lower 48 states, and therefore, have an incentive to restrict third party throughput, but that an independent, non-integrated pipeline owner would not. The Memo argues that the Producers would want to restrict third party throughput in order to maintain supra-competitive natural gas prices in the lower 48 States. The premise is demonstrably false, however, because the Producers do not have market power in any downstream market for the sale of natural gas. According to the Lukens Energy Group, the Producers' projected shares of natural gas sales in the lower 48 states in 2015 (when the pipeline comes on line) are: 7.9% for ExxonMobil, 7.3% for BP, and 5.8% for ConocoPhillips.[7]

Because of their small shares of downstream natural gas sales, the Producers lack market power. Thus, any actions that the Producers might take to reduce their rivals' throughput on the Gas Pipeline would not affect the price of natural gas to customers in the lower 48 states. On the other hand, by restricting throughput from third party shipments, the Producers would forgo a return on those third party shipments as well as the ability to spread the fixed costs of the Gas Pipeline over greater volume.

Greenberg Traurig goes on to also argue, however, that the relevant market for antitrust purposes might not be the lower 48 states as a whole, but rather that relevant gas markets might be localized at certain locations – suggesting as possibilities both Chicago and other unidentified

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[6] In theory, the individual Producers could offer competing proposals to build the only pipeline, but no one has suggested that this loss of "engineering rivalry" is a concern.

[7] These are "equity shares," that is, shares of natural gas sales actually owned or under long term lease by the seller. Equity shares are the best measure for these purposes because brokers do not benefit from supra-competitive prices for gas owned by third parties.

Greenberg Traurig relies on higher shares calculated by attributing to the Producers sales they made as agents on behalf of other, third party owners (Memo at 3). It is not economically correct to inflate and then aggregate the shares of rivals in this way. Even when this incorrect approach is taken, the Memo barely elevates the market shares to the 35% threshold at which the DOJ and FTC Merger Guidelines recognize there may be an issue of market power for sellers of undifferentiated products, such as sellers of natural gas. *See* US Department of Justice and the Federal Trade Commission, Horizontal Merger Guidelines, § 2.22.

"Mid-Continent" areas. (Memo at 13). Even assuming that a local Chicago market for natural gas could be properly defined as a relevant market for antitrust analysis, the Producers would not have market power in that market.[8] For gas sold and transported on pipelines to the Chicago hub, the combined share of inbound pipeline capacity held by the North Slope Producers is less than 6% of the total, with BP being the largest with 3.13%.[9] Either individually or collectively, the market shares held by the Producers at pipeline hubs such as Chicago are simply too small to permit the exercise of market power.[10]

Even assuming – contrary to fact – that the Producers would have market power over the price of natural gas in the lower 48 states, or any smaller area, FERC regulations would constrain them from using their control of the pipeline to increase prices to natural gas customers. As will be discussed further in Part D below, FERC regulations prevent anticompetitive conduct by pipeline owners by requiring the Alaska gas pipeline to provide open and non-discriminatory access, tariffs, and services to all shippers, to increase capacity if demanded by shippers that genuinely need it, and to separate gas marketing from pipeline functions. Therefore, absent FERC's abdication of its regulatory power, which the Memo does not suggest would occur, the Producers could not use the pipeline in an anticompetitive manner, even if they wanted to do so.

C. The Producers Would Have the Same Incentive to Solicit Third Party Shippers to Ship on the Gas Pipeline as an Independent Owner.

Greenberg Traurig argues that a Producer-owned pipeline would not have the same incentives to increase throughput by third party shippers as an independent owner would. This is not correct. As owners of the Gas Pipeline, the Producers clearly would have an incentive to encourage third party shipments on the pipeline. By increasing throughput, the Producers will not only earn a return on the third party shipments, but also spread the fixed costs of pipeline operation over a greater amount of gas, thereby reducing shipping costs for the Producers' production affiliates. Increasing throughput increases efficiency, reduces average shipping costs, and, subject to any regulatory constraints, results in more profit to the owners. Because allowing

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[8] The proposed pipeline's gas could be routed to Chicago via Alberta.

[9] Because data on equity sales of gas at the Chicago hub is not available, we are using pipeline capacity shares calculated by the Lukens Energy Group as a proxy for equity sales shares. The market share of each of the Producers represents the ratio of firm capacity held by the Producer to the total contracted firm capacity for all of the pipelines transporting gas into the Chicago hub. Since the capacity may be used to transport remarketed gas, the capacity shares likely overstate the equity sales shares of the companies.

Pipeline capacity shares can also be meaningful in and of themselves. If the Producers attempted to restrict Alaska natural gas deliveries into the hub, there would be numerous competing owners of pipeline capacity serving that hub that could (and would) use their capacity to increase the supply of competing gas through the hub. Therefore, unless the Producers had such a significant share of the pipeline capacity at the hubs to "crowd out" virtually all competing sellers of gas, they would not have the ability to affect the price of gas at the hub.

[10] Greenberg Traurig identifies no other "Mid-Continent" hubs about which to be concerned. Because the volume of North Slope gas delivered at any downstream hub in the United States beyond Chicago would only diminish, there is no reason to believe the Producers would have a share "in other Mid-Continent areas" large enough to confer market power.

Even if we examine Producer shares further upstream from Chicago at Alberta, the shares are not significantly higher. According to the Lukens Energy Group, the combined Producer share of outbound pipeline capacity at Alberta is less than ten percent, with BP having 6.4%.

increased amounts of third party shipments is profitable to any pipeline owner – Producer or independent – the incentive to allow third party shipments is strong for both types of owners.

The Memo nevertheless constructs speculative theories of exclusionary conduct by the Producers. A necessary (but not sufficient) predicate for any theory of exclusionary conduct is that the pipeline owner(s) have significant market power in a relevant downstream market for natural gas. As noted in Part II.A above, the Producers have much too small a share of the owned (equity) natural gas in the lower 48 to affect price. But even if the Producers somehow acquired some ability to affect price in the lower 48 by reducing third party throughput, the increased profits from the higher gas prices hypothesized from such a strategy would have to (1) exceed the foregone profits from the throughput tariff revenues third parties would have paid, and (2) escape FERC detection and remedies under its open access regulations. Given the strong incentive to encourage third party shipments on the pipeline, there is no reason to believe the first condition would be met. As explained below, it is also unlikely that the second condition would be met.

D. The Gas Pipeline Act and the Open Season Regulations Ensure That a Producer-Owned Pipeline Would Not Have the Ability to Discriminate Against Rivals.

Greenberg Traurig relies heavily on the Attorney General's 1977 report to President Carter identifying potential competitive concerns relating to a producer-owned pipeline.[11] The report concluded that producer-ownership of the pipeline would create incentives to deny or impede future capacity expansion. Both the structure of the natural gas industry and the applicable regulatory regime have changed significantly since the 1977 report. FERC now requires that a company's transportation affiliate operate independently of the company's marketing affiliate. 18 C.F.R. § 358.4 (2005). Additionally, the FERC regulations require that the Alaska Gas Pipeline hold open seasons in order to provide all shippers an equal opportunity to bid for pipeline capacity. *See* Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects, 70 Fed. Reg. 8269 (Feb. 18, 2005), Order No. 2005, Docket No. RM05-1-000, (to be codified at 18 C.F.R. pt. 157) (the "Open Season Regulations").

The Gas Pipeline Act, the Open Season Regulations, and the FERC Standards of Conduct all contain provisions designed to prevent the owners of the Gas Pipeline from using the pipeline for anticompetitive purposes. The Open Season Regulations ensure that FERC can and will take action to preserve competition. In Order 2005, the Commission explained that it was "imposing strict requirements on all proposals . . . to ensure that there is a level playing field. As we discuss below, we will require applicants for an Alaska pipeline project to provide detailed information as to project design, how capacity is to be allocated, and proposed rates, terms and conditions. This will allow us to be in a position to monitor whether competition for capacity is fair." 110 FERC ¶ 61,095 at Paragraph 12 (2005).

Even assuming that the Producers had market power downstream, the application process at FERC for a certificate of public convenience and necessity would alleviate concerns that the

[11] The end result of that report was a condition in President Carter's Decision prohibiting the producers from equity ownership. This proved unworkable and the condition was removed in 1981.

Producers would build a purposefully undersized Gas Pipeline in order to prevent third party shippers from competing with them in the downstream market for the sale of gas. In considering any certificate application, "the Commission will consider the extent to which a proposed project has been designed to accommodate the needs of shippers who have made conforming bids during open season, as well as the extent to which the project can accommodate low-cost expansion, and may require changes in project design necessary to promote competition and offer a reasonable opportunity for access to the project." 18 C.F.R. § 157.37 (2005). Moreover, the Open Season Regulations and Order 2005 demonstrate that the Commission will enforce its requirements that a Gas Pipeline be designed in order to accommodate all shippers who make genuine bids for capacity. Furthermore, a third party shipper can bring a complaint at the Commission about the Producers' proposal if the shipper believes that the Producers are proposing to build a Gas Pipeline that has insufficient capacity, and it may seek Commission action to address its concern.

Even after the construction of Gas Pipeline, there should not be any substantial concern that the Producer-owners of the Gas Pipeline have the ability to "crowd out" third party shippers or refuse to expand the capacity of the Gas Pipeline for anticompetitive reasons. Section 105(a) of the Gas Pipeline Act gives FERC the authority to "order the expansion of the Alaska natural gas project if the Commission determines that such expansion is required by the present and future public convenience and necessity." Consequently, if a third party shipper believes that the Gas Pipeline has impermissibly refused to increase its capacity, it can seek relief from the Commission.

Moreover, the Natural Gas Act's antidiscrimination provisions and the Standards of Conduct regulations would preclude efforts by the Producers to favor their shipping affiliates to the detriment of third party shippers. Under the Natural Gas Act, a gas pipeline may not grant any "undue preference or advantage" to any shipper, subject any shipper to "undue prejudice or disadvantage," or "maintain any unreasonable differences in rates, charges, service, facilities or in any other respect." 15 U.S.C. § 717c (b). Similarly, under FERC's Standards of Conduct, a gas pipeline "must treat all transmission customers, affiliated and non-affiliated, on a nondiscriminatory basis, and must not operate its transmission system to preferentially benefit an Energy Affiliate." 18 C.F.R. § 358.2(b). Consequently, the Producer-owners can not discriminate in favor of their own production (shipping) affiliates in order to give them a competitive advantage over a third party shipper.

III. The Potential Remedies Proposed by Greenberg Traurig Are Neither Likely Nor Feasible.

Despite the lack of a tangible antitrust concern, and the presence of extensive open access regulation by FERC, regulations, the Memo maintains that there is a chance that FERC would choose to go beyond its comprehensive regulations and impose additional remedies on a Producer-owned Gas Pipeline. Based on this possibility, the Memo asserts that a Producer-owned pipeline would face burdensome and time-consuming regulatory hurdles that an

independent pipeline could avoid.[12] The Memo asserts that potential remedies include divestiture, establishment of an independent system operator, or imposition of a market monitor. However, given the existence of pervasive agency regulation, the probability that remedies such as these would be instituted by either the FERC or the FTC is extremely low. With respect to potential FTC action, Greenberg Traurig cites no support for the proposition that vertical integration through internal expansion would raise antitrust concerns at the FTC. The Memo instead offers three FTC cases (at 8) in support of its conclusions. None of these FTC cases, however, involved situations where the parties had vertically integrated through internal expansion, and are therefore not instructive here.

Greenberg Traurig suggests that the Producers may be required to sever their relationships with both their upstream and downstream affiliates through some sort of divestiture, resulting in an entity that only holds the ownership of the pipeline (even though the initial funding and personnel for the entity would come from the Producers). In support of this position, the Memo argues that the FTC has used this divestiture method in the past. However, the Memo fails to cite any case in the entire energy sector to support its contention that the FTC would act in such a manner. In addition, the Memo does not sufficiently explain why divestiture is a preferable remedy compared to the FERC regulation that would otherwise control the pipeline. Moreover, it is unlikely that the FERC would conclude that the regulatory structure it has used to ensure access to gas pipelines in the lower 48 is insufficient to protect shippers for the Gas Pipeline.

The other remedies suggested by the Memo are even more implausible. While establishing an independent system operator or a market monitor may well address third party shippers' fears of potential anticompetitive Producer-owner conduct, FERC has never required a natural gas pipeline to transfer control of its facilities to an independent operator – a point conceded by Greenberg Traurig. Moreover, the Memo fails to explain why such a radical remedy is necessary or desirable, or and why conventional regulation is insufficient to keep the Producer-owners' conduct under control.

In conclusion, based on the facts we know today, it is highly unlikely that the Federal Energy Regulatory Commission would deny a certificate of public convenience and necessity to a Producer-owned Gas Pipeline based on the competitive issues raised by Greenberg Traurig. Existing antitrust law and FERC regulation are sufficient to prevent and address any competitive issues that may arise.

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[12] The Memo argues that there is a significant risk of a delay of the certificate application process at FERC due to potential third party complaints against a producer-owned pipeline, and that such a risk of delay would not exist if the application were submitted by an independent pipeline owner. However, the Memo neglects to consider that Sections 103 and 104 of the Alaska Natural Gas Pipeline Act of 2004 place a twenty month total time limit on the issuance of a certificate at FERC; the Commission must issue (or decline to issue) a certificate no later than 60 days after the issuance of a final environmental impact statement. *See* ANGPA § 103(c) and § 104(d). Therefore, Mmesinger and Chung's argument that protests over competitive issues would necessarily delay the issuance of a certificate misses a key fact.

Attachment 3:

Access to Alaska Gas Pipeline and "Basin Control"

A presentation dated July 13, 2006 by Robert H. Loeffler

and

A memo dated October 18, 2006 by Bradley Lui, et al.

Morrison and Foerster LLP

Access to Alaska Gas Pipeline and "Basin Control"

Robert H. Loeffler
Partner
Morrison and Foerster LLP

July 13, 2006

ACCESS AND BASIN CONTROL OVERVIEW

- Alaska Gas Pipeline ("AGP") will be a tightly regulated "open access" pipeline
- Pipeline operations must be legally separate from marketing affiliates – the law requires gas and pipeline transportation to be sold separately
- Affiliate restrictions enforced by new, heavy penalties
- FERC reviews competitive issues including size and expandability as part of its approval process
- FERC has unique powers to mandate expansion of this pipeline to protect unaffiliated explorers and shippers
- AGP will be the most scrutinized pipeline in the U.S. over its life

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ACCESS AND BASIN CONTROL
PRODUCER PIPELINE OWNERSHIP

- Past efforts to prohibit producer ownership of AGP were counter-productive
- Congress did not prohibit producer ownership of AGP when it enacted Alaska Natural Gas Pipeline Act ("ANGPA")

3

ACCESS AND BASIN CONTROL
RELATIONSHIP OF GAS, PIPELINE, AND CAPACITY OWNERS

Order 636 and following orders changed dramatically how pipelines and producers conduct their business:

- After Order 636, pipeline companies do not own or sell gas; they just sell transportation services
- Separate companies -- affiliated or not -- sell gas
- Owning the pipeline no longer gives the owner transportation (capacity) rights
  - pipeline owner must put out for bid all capacity
  - pipeline affiliates may bid on the capacity but have no assurance of winning
- Likewise, owning the gas in the basin connected to the pipeline does not entitle a producer to capacity absent a winning bid

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ACCESS AND BASIN CONTROL

THE PERVASIVE NATURE OF FERC REGULATION OF INTERSTATE GAS PIPELINES

- FERC reviews and approves all aspects of an interstate pipeline
  - Permitting
  - Design of facilities
  - Size of facilities
  - Access to facilities
  - Open seasons
  - Tariff rates
  - Operations
  - Expansions
  - Abandonment
- This will be especially so for AGP. For example,
  - FERC will consider how the project design considers the capacity needs of initial and future shippers (18 CFR § 157.36)
  - AGP must even consider any bids tendered after the expiration of the open season and can only reject them if economic, engineering or operational constraints do not allow the pipeline to accommodate the bids (18 CFR § 157.34 (d)(2))
  - As stated by FERC: "Our expectation is that an Alaska gas transportation project will be designed and built, to the extent possible, to accommodate all qualified shippers who are ready to sign firm transportation agreements" (Order 2005-A at ¶ 34)

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ACCESS AND BASIN CONTROL

THE LEGAL FRAMEWORK

- Natural Gas Act of 1938 ("NGA")
- Natural Gas Policy Act of 1978 ("NGPA")
- Alaska Natural Gas Policy Act of 2004 ("ANGPA")
- Energy Policy Act of 2005 ("EPAct")
- FERC Orders
  - Order 436 (1985)
  - Order 636 (1992)
  - Order 637 (2000)
  - Order 2004, 2004-A-D (2003)
  - Order 2005, 2005-A (2005)
  - Order 670 (2006)

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ACCESS AND BASIN CONTROL

PHASES OF FERC REGULATION

1. Open Season
2. FERC Application process that results in a certificate
3. Pipeline construction
4. Pipeline

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PART II

EVOLUTION OF FERC'S AFFILIATE/SEPARATION OF FUNCTIONS REGULATIONS

NATURAL GAS RESTRUCTURING – OPEN ACCESS/ORDER 436

- FERC's issuance of Order 436 in 1985:
  - Required interstate pipelines that offer transportation services to do so on an open-access, nondiscriminatory basis
  - Pipeline customers could now contract directly with producers for gas supply and transport it on the pipelines
  - Pipelines were encouraged to provide transportation to those customers who requested it

NATURAL GAS RESTRUCTURING – ORDER 636/UNBUNDLING

- FERC's issuance of Order 636 in 1992:
  - Required interstate pipelines to unbundle their commodity gas sales from transportation and storage services
  - Services were defined in new tariffs
  - Pipelines were given blanket sales certificates to allow for the unbundled sale of gas at market-based rates
  - However, such gas sales generally performed by marketing affiliates
  - Market Centers quickly evolved for gas trading

NATURAL GAS RESTRUCTURING – ORDER 636/CAPACITY

- Provided terms and structure for a capacity release program whereby capacity holders could release their un-utilized pipeline capacity to replacement shippers
- FERC requires a capacity release mechanism with open-access bidding, rather than assignment provisions, so as to foster open, competitive markets

NATURAL GAS RESTRUCTURING – ORDER 637

FERC's issuance of Order 637 enhanced Order 636:

- Increased informational reporting requirements for interstate pipelines
  - More stringent standards of conduct information
  - Enhanced information for firm, interruptible, storage, and capacity release transactions and for the Index of Customers
  - Enhanced scheduling provisions
  - Enhanced capacity segmentation rights
  - Mandatory provision of imbalance services
  - Encouragement of new rate forms for services
    - Peak and off-peak rates
    - Term-differentiated rates

PART III

FERC'S ENFORCEMENT POWERS DURING PIPELINE OPERATIONS

MONITORING OF NATURAL GAS DEREGULATION – ORDER 2004/STANDARDS OF CONDUCT

Order 2004 and Orders 2004-A-D, released in 2003-04:

- Set Standards of Conduct designed to ensure open access and competition by non-affiliated customers
- Barred undue preferential treatment by providers to their marketing affiliates:
  - Required provider's transmission function employees to operate independently from marketing employees or other energy affiliates (18 CFR 358.4(a))
  - Provider's sales and marketing units, energy affiliates, and potential merger partners must be posted on its website (18 CFR 358.4(b))
  - Ensure that non-affiliated customers have equal access to information about transmission, operations, price (18 CFR 358.5(a))
- Recognized post-unbundling market expansion that included growth of physical and financial transactions by marketing and non-marketing gas pipeline affiliates

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FERC'S ORIGINAL ENFORCEMENT TOOLS UNDER NGA (1938) AND NGPA (1978)

- Can order disgorgement of unjust profits
- Can condition, suspend or revoke
  - Market-based rate authority
  - Certificate authority
  - Blanket certificate authority
- Minor penalty provisions
  - Both the NGA and NGPA had minor penalty provisions in the $500 to $5000 range

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FERC'S NEW ENFORCEMENT TOOLS UNDER EPAct

- EPAct granted FERC greatly enhanced authority to assess civil and criminal penalties
  - Congress extended FERC's civil penalty authority to cover violations of the NGA or any rule or regulation imposed under NGA authority (EPAct section 314(b))
  - Congress increased the maximum civil penalty under the NGA and NGPA to $1 million per violation for each day the violation continues (EPAct section 314(b))
  - Congress increased the maximum criminal fine under the NGA and NGPA to $1 million and the maximum imprisonment time to 5 years (EPAct section 314(a))

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FERC'S ENFORCEMENT TOOLS UNDER EPAct...cont.

- FERC's October 2005 Policy Statement on enforcement listed several factors it would consider in determining the appropriate penalties. Among those:
  - What harm was caused
  - Was the harm widespread across markets or customers
  - What efforts did the company make to remedy the violation in a timely manner
  - Was the conduct fraudulent; was it the result of manipulation, deceit or artifice
  - Did the wrongdoer act in concert with others
  - Was this a repeat offense
  - How long did the wrongdoing last
  - Was the wrongdoing related to actions by senior management and was there any cover-up
  - Did management impede any inquiry into the wrongdoing
  - What effect would the penalties have on the financial viability of the company

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CONCLUSION

In FERC's own words: "Entities subject to the Commission's jurisdiction should expect firm but fair enforcement in the future, including the use, as appropriate, of the substantial new civil penalty authority provided by EPAct 2005."

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ORDER 670: PROHIBITION OF ENERGY MARKET MANIPULATION

- In January 2006 FERC issued regulations pursuant to its new EPAct 2005 authority
- Order bars energy market manipulation by "any entity" (not just jurisdictional entities)
- If the entity's conduct is "in connection with" a jurisdictional transaction, it is subject to FERC's anti-manipulation authority
- Order makes it unlawful for any entity in connection with gas and transportation purchases and sales to
  - Defraud using any device, scheme or artifice,
  - Make any untrue statement of material fact or omit a material fact, or
  - Engage in any act, practice, or course of business that operates as a fraud or deceit

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ORDER 670: PROHIBITION OF ENERGY MARKET MANIPULATION...cont.

- Fraud is defined to include "any action, transaction, or conspiracy for the purpose of impairing, obstructing or defeating the honest functioning of the market."
- There also must be a showing of intent to deceive or defraud, that is, "scienter" as established under securities law.

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PART IV

THE ALASKA OPEN SEASON REGULATIONS

OPEN SEASON REGULATIONS FOR THE ALASKA PIPELINE
OVERVIEW

- ANGPA directed FERC to issue regulations governing the conduct of open seasons, the first such regulations ever issued by it
- Comprehensive regulations were issued in 2005 (Orders 2005 and 2005-A) that cover procedures for the allocation of capacity and criteria for and timing of any open season
- FERC's stated goals are an open season process that
  - provides economic certainty to support the building of the pipeline
  - promotes competition in the exploration, development and production of Alaska natural gas
  - prevents unduly discriminatory behavior and limits the ability of a project applicant to unduly favor its affiliate -- hence, Order 2004 Standards of Conduct apply
- Regulations apply to any initial capacity or voluntary expansion capacity
- In sum, regulations provide FERC with an additional tool over and above its other enforcement tools to actively and closely police all capacity related conduct for the Alaska pipeline.

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OPEN SEASON REGULATIONS FOR THE ALASKA PIPELINE

OVERVIEW...cont.

- FERC will review the open season notice in advance of its publication
- At least 30 days notice must be given of start of open season
- The open season must remain open for at least 90 days once precedent agreements are signed, they must be disclosed and filed with FERC
- Open season notice will contain extensive information about the project, including a proposed tariff and technical data
  - See 18 CFR 157.34 (reproduced in appendix)

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INFORMATION AVAILABILITY

18 CFR 157.34

- "(18) All information pertaining to the proposed service to be offered, projected pipeline capacity and design, proposed tariff provisions, and cost projections, made available to or in the hands of any potential shipper, including any affiliates of the project sponsor and any shippers with pre-subscribed capacity, prior to the issuance of the public notice of open season;"

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CERTIFICATION BY SALES AND MARKETING UNITS
18 CFR 157.34

- "(21) A statement that any officers and directors of the prospective applicant's affiliated sales and marketing units and Energy Affiliates involved in the production of natural gas in the State of Alaska named in paragraph (c)(19) of this section will be prohibited from obtaining information about the conduct of the open season or allocation of capacity that is not posted on the "open season" Internet website or that is not otherwise also available to the general public or other participants in the open season."

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UNDUE DISCRIMINATION OR PREFERENCE PROHIBITIONS
18 C.F.R. 157.35

- "(a) All binding open seasons shall be conducted without undue discrimination or preference in the rates, terms or conditions of service and all capacity allocated as a result of any open season shall be awarded without undue discriminations or preference of any kind.
- (b) Any complaint filed pursuant to §385.206 of this chapter alleging non-compliance with any of the requirements of this subpart shall be processed under the Commission's Fast Track Processing procedures contained in §385.206 (h).

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UNDUE DISCRIMINATION OR PREFERENCE PROHIBITIONS

18 C.F.R. 157.35...cont.

- (c) Each project applicant conducting an open season under this subpart must create or designate a unit or division to conduct the open season that must function independent of the other divisions of the project applicant as well as the project applicant's Marketing and Energy affiliates as those terms are defined in §385(d) and (k) of this chapter."
- (d) The relevant Order 2004 Standard of Conduct provisions apply
  - Separation of transmission function employees from marketing and energy affiliate employees
  - Information access for marketing and energy affiliate employees that is only what the transmission employees provide to their transmission customers
  - Information disclosure that does not favor marketing and energy affiliate employees
  - No preferences to affiliates for transmission service
  - Discounts that must be completely transparent

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UNDUE DISCRIMINATION OR PREFERENCE PROHIBITIONS

18 C.F.R. 157.35...cont.

- (e) The Mainline LLC will have to post on its internet website written procedures describing how it will comply with Order 2004
- (f) The Mainline LLC will also have to designate a Chief Compliance Officer and train its employees on the open season requirements
- (g) As FERC concluded: "The application of some of the non-discrimination requirements of Order No. 2004 will broadly prohibit discrimination by a project applicant conducting an open season and limiting its ability to unduly favor a Marketing/Energy Affiliate."

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BID TERMS – FERC ORDER 2005

- "[T]he Commission will be reviewing the results of any open season processes to determine the appropriateness of any unusually long contract terms (e.g., a term exceeding the projected life of the pipe) to determine whether shippers incorporated them in their bids to obtain capacity allocation. For example, it would be in a prospective shipper's economic interest to seek a contract term that would be sufficient to allow the recovery of its revenues. However, it would not be in a shipper's economic to bid for capacity beyond its projected reserve's life because it would expose the shipper to reservation charges it may not be able to recover."

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PART V

JOHNSTON TESTIMONY

BASIN CONTROL AND BASIN MASTERY

- What allegedly is "basin control?"
  - Producer owned pipeline would favor production affiliates to the exclusion of independents in decisions on operation and expansion of pipeline so as to control development on the North Slope

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FERC TOOLS TO ADDRESS BASIN CONTROL, SUMMARY

- FERC has a strong set of tools to address basin control
- FERC has both structural and behavioral remedies
- FERC has adopted special requirements for AGP to foreclose anti-competitive behavior
- FERC will review anti-competitive behavior in the open season, in the certification process, and during operations
- FERC has unique power to order expansion to protect independents

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Daniel Johnston Testimony on SB 305 and HB 488
April 9, 2006

- "The cornerstone of this type of control [as basin master] is their dominant position in early infrastructure corridors (often over-built, with a view towards future discoveries), which allows the basin masters to extract rents from other players through access charges to this infrastructure."

- Alaska is not a third world country.
- Access to the pipeline and the pipeline itself are highly regulated to ensure fairness
- Federal and state leases are awarded by competitive bid
- Access charges (pipeline rates) are regulated

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APPENDIX

APPENDIX
OPEN SEASON NOTICE REQUIREMENTS
18 C.F.R. 157.34

The regulations provide the following:

- "(c) *Contents of notice.* Notice of the open seasen required in paragraph (a) of this section, shall contain at least the following information; however, to the extent that any item of such information is not known or determined at the time the notice is issued, the prospective applicant shall make a good faith estimate based on the best information available of all such unknown or undetermined items of required information and further, must identify the source of information relied on, explain why such information is not presently known, and update the information when and if it is later determined during the open season period:
- (1) The general route of the proposed project, including receipt and delivery points, and any alternative routes under consideration; delivery points must include those within the State of Alaska as determined by the In-State Study in paragraph (b) of this section;
- (2) Size and design capacity (including proposed certificate capacity at the delivery points named in paragraph (c)(1) of this section to the extent that it differs from design capacity), a description of possible designs for expanded capacity beyond initial capacity, together with any estimated date when such expansions designs may be considered;
- (3) Maximum allowable operating pressure and expected actual operating pressure;
- (4) Delivery pressure at all delivery points named in paragraph *(c)(1)* of this section,
- (5) Projected in-service date;

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APPENDIX...cont.
OPEN SEASON NOTICE REQUIREMENTS
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- (6) An estimated unbundled transportation rate for each delivery point named in paragraph (c)(1) of this section, stated on a volumetric or thermal basis, for each service offered, including reservation rates for pipeline capacity, interruptible transportation rates, usage rates, fuel retention percentages, and other applicable charges, or surcharges, such as the Annual Charge Adjustment (ACA); (if rates are estimated on a volumetric basis then the notice must inform bidders that final pro forma service agreements and the sponsor's proposed FERC tariff will have to be submitted with rates based on a thermal basis.)
- (7) The estimated cost of service *(i.e.,* estimated cost of facilities, depreciation, rate of return and capitalization, taxes and operational and maintenance expenses), and estimated cost allocations, rate design volumes and rate design;
- (8) Based on the In-State Study and the delivery points within the State of Alaska identified in paragraph (c)(1) of this section, there must be an estimated transportation rate for such deliveries, based on the amount of in-state needs shown in the study. Such estimated transportation rate must be based on the costs to make such in-state deliveries and shall not include costs to make deliveries outside the State of Alaska;
- (9) Negotiated rate and other rate options under consideration, including any rate amounts and terms of any precedent agreements with prospective anchor shippers that have been negotiated or agreed to outside of the open season process proscribed herein;

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APPENDIX ...cont.
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- (10) Quality specifications and any other requirements applicable to gas to be delivered to the project provided that a prospective applicant shall not require that potential shippers process or treat their gas at any designated plant or facility;
- (11) Terms and conditions for each service offered;
- (12) Creditworthiness standards to be applied to, and any collateral requirements for, prospective shippers;
- (13) The date, if any, by which potential shippers and the prospective applicant must execute precedent agreements;
- (14) A detailed methodology for determining the value of bids for deliveries within the State of Alaska and for deliveries outside the State of Alaska;
- (15) The methodology by which capacity will be awarded, in the case of over-subscription, clearly stating all terms that will be considered, including price and contract term. If capacity is oversubscribed and the prospective applicant does not redesign the project to accommodate all capacity requests, only capacity that has been acquired through pre-subscription or was bid in the open season on the same rates, terms, and conditions as any of the pre-subscription agreements shall be subject to allocation on a pro rata basis; no capacity acquired through the open season shall be allocated.
- (16) Required bid information, whether bids are binding or non-binding, receipt and delivery point requirements, the form of a precedent agreement and time of execution of the precedent agreement, definition and treatment of non-conforming bids;
- (17) The projected date for filing an application with the Commission;

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APPENDIX...cont.
OPEN SEASON NOTICE REQUIREMENTS
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- (18) All information pertaining to the proposed service to be offered, projected pipeline capacity and design, proposed tariff provisions, and cost projections, made available to or in the hands of any potential shipper, including any affiliates of the project sponsor and any shippers with pre-subscribed capacity, prior to the issuance of the public notice of open season.
- (19) A list of the names and addresses of the prospective applicant's affiliated sales and marketing units and Energy Affiliates involved in the production of natural gas in the State of Alaska. Affiliated unit means "Affiliate" as applicably defined in §358.3(b) of this chapter. Energy Affiliate means "Energy Affiliate" as applicably defined in §358.3(d) of this chapter.
- (20) A comprehensive organizational chart showing: (i) The organizational structure of the prospective applicant's parent corporation(s) with the relative position in the corporate structure of marketing and sales units and any Energy Affiliates involved in the production of natural gas in the State of Alaska; (ii) The job titles and descriptions, and chain of command for all officers and directors of the prospective applicant's marketing and sales units and any Energy Affiliates involved in the production of natural gas in the State of Alaska; and
- (21) A statement that any officers and directors of the prospective applicant's affiliated sales and marketing units and Energy Affiliates involved in the production of natural gas in the State of Alaska named in paragraph (e)(19) of this section will be prohibited from obtaining information about the conduct of the open season or allocation of capacity that is not posted on the "open season" Internet website or that is not otherwise also available to the general public or other participants in the open season.

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CORRECTION

THE FOLLOWING DOCUMENT(S)
HAVE BEEN REFILMED TO
ASSURE LEGIBILITY OR PAGINATION

APPENDIX ...cont.
OPEN SEASON NOTICE REQUIREMENTS
18 C.F.R. 157.34

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- (17) The projected date for filing an application with the Commission;

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APPENDIX...cont.
OPEN SEASON NOTICE REQUIREMENTS
18 C.F.R. 157.34...cont.

- (18) All information pertaining to the proposed service to be offered, projected pipeline capacity and design, proposed tariff provisions, and cost projections, made available to or in the hands of any potential shipper, including any affiliates of the project sponsor and any shippers with pre-subscribed capacity, prior to the issuance of the public notice of open season;
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- (20) A comprehensive organizational chart showing: (i) The organizational structure of the prospective applicant's parent corporation(s) with the relative position in the corporate structure of marketing and sales units and any Energy Affiliates involved in the production of natural gas in the State of Alaska; (ii) The job titles and descriptions, and chain of command for all officers and directors of the prospective applicant's marketing and sales units and any Energy Affiliates involved in the production of natural gas in the State of Alaska; and
- (21) A statement that any officers and directors of the prospective applicant's affiliated sales and marketing units and Energy Affiliates involved in the production of natural gas in the State of Alaska named in paragraph (e)(19) of this section will be prohibited from obtaining information about the conduct of the open season or allocation of capacity that is not posted on the "open season" Internet website or that is not otherwise also available to the general public or other participants in the open season."

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MEMORANDUM

TO: State of Alaska COPIES: Robert H. Loeffler

FROM: Bradley S. Lui
Roger W. Fones
Jeny M. Marcinko[1]

DATE: October 18, 2006 FILE: 08083/93

RE: Alaska Natural Gas Pipeline - Producer Owned Pipeline Project

This memo addresses arguments raised in an April 22, 2006 memorandum from Kenneth M. Minesinger and Cecil Chung of the Greenberg Traurig law firm to Senator Therriault, Representative Samuels and others ("Greenberg Traurig" or "Memo"). The Memo is entitled "Competitive Analysis of Producer-Owned Alaska Natural Gas Pipeline," and argues that potential competitive issues might arise if the three largest owners of the proven natural gas reserves on the North Slope, *i.e.* BP, ConocoPhillips, and ExxonMobil (individually, a "Producer" and collectively, the "Producers") were to build, own and operate a pipeline to transport natural gas from the North Slope to Canada and ultimately to the lower 48 states (the "Gas Pipeline"). The Memo contends that (1) in 1977, the U.S. Attorney General identified potential competitive concerns with Producer ownership of a Gas Pipeline; (2) the risks presented by these competitive issues continue to exist today, and (3) consideration of these issues will cause significant delays in any proceedings regarding whether to approve a Producer-owned Gas Pipeline.

Contrary to conclusions reached by Greenberg Traurig, Producer ownership of the Gas Pipeline does not raise significant competitive concerns. As the Memo acknowledges, joint ownership by the Producers does not by its nature violate the antitrust laws. Moreover, because the Producer-owners lack downstream market power, a Producer-owned pipeline has no incentive to discriminate against third party shippers. Even if the Producers did possess downstream market power, the requirements of the Alaska Natural Gas Pipeline Act as well as the FERC regulations implementing that Act provide sufficient safeguards to prevent the Producers from operating the pipeline in an anticompetitive manner. Under these conditions, Producer joint ownership does not create significant antitrust issues.

I. Producer Ownership of the Gas Pipeline Would Not Violate the Antitrust Laws

A. Producer Ownership Will Not Reduce Existing or Potential Competition Among the Owners

[1] Brad Lui and Roger Fones are partners, and Jeny Marcinko is an associate, in the antitrust practice group of Morrison and Foerster. Mr. Fones was Chief of the Transportation, Energy & Agriculture Section of the Antitrust Division from 1993-2005. Mr.Lui was a trial attorney in the Antitrust Division before joining Morrison and Foerster.

Under Section 7 of the Clayton Act, 15 U.S.C. § 18 and Section 1 of the Sherman Act, 15 U.S.C. § 1, the formation of a joint venture is unlawful only if the effect of the transaction is to lessen competition substantially in one or more relevant markets. This analysis is performed by evaluating the markets in which the parties compete, their market shares, and the likelihood that their collaboration would lessen competition in those markets.[2]

Under the legal standards of the Clayton and Sherman Acts, a Producer-owned pipeline is not likely to reduce competition substantially in any relevant market.[3] A Producer-owned pipeline would only increase competition in the market for transportation of natural gas because none of the North Slope's gas reserves are currently being transported to consumers in the lower 48 states. The increase in the overall supply of gas into the lower 48 will increase – not decrease – the level of competition for the downstream sale of gas above what existed *ex ante*. Likewise, there would be no reduction in competition in the exploration and production of North Slope gas. Indeed, incentives for competition in the exploration and production of North Slope gas should be enhanced since the product of that exploration and production will be able to reach consumers in the lower 48 States. For these reasons, the formation of the joint venture by the Producers to build and operate the Gas Pipeline would not violate the antitrust laws.[4]

B. Producer Ownership Will Not Lead to Lessened Competition, Higher Tariffs, or Reduced Throughput in the Transportation of North Slope Natural Gas, as Compared to an Independent Pipeline.

Any natural gas pipeline for North Slope gas must be authorized by the FERC pursuant to the Alaska Natural Gas Pipeline Act (the "Gas Pipeline Act"). As Greenberg Traurig acknowledges, there will be only one Gas Pipeline built.[5] Thus, regardless of ownership, the Gas Pipeline will have a monopoly over transportation from the North Slope. Accordingly, the Gas Pipeline's tariffs, capacity, and access will all be regulated by FERC, which will protect non-affiliated shippers against unreasonably high tariffs and limited access.

II. A Producer-Owned Pipeline Is Unlikely to Impose Anticompetitive Vertical Restraints

A. Vertical Integration Is Not Inherently Suspect Under the Antitrust Laws.

The Greenberg Traurig Memo correctly notes (at 8) that most vertical mergers do not raise competitive concerns. The Memo also implicitly acknowledges that the Producers' proposal is not a merger, but nevertheless proceeds with a discussion based on the following premise: "[T]he Alaska pipeline had already been built and then acquired" by the Producers.

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[2] A more detailed explanation of the three-step analysis involved in evaluating the lawfulness of the joint venture is contained in the previous memorandum from Morrison & Foerster to the State of Alaska, dated March 11, 2005.

[3] The bases for these conclusions are discussed in detail in the March 11, 2005 Morrison & Foerster memorandum on page 5.

[4] The Greenberg Traurig Memo concedes this point on page 6 ("the formation of the joint venture would generally be lawful").

[5] It is extremely unlikely that any of the individual Producers would be in the position to build its own pipeline (separate from the proposed pipeline). Therefore, the fact that the Producers are collaborating in building the pipeline does not reduce potential competition in the transportation of gas from the North Slope.

The Memo then embarks on a lengthy discussion of vertical merger precedents at FTC, DOJ and FERC. This merger discussion is largely irrelevant because it fails to analyze the situation at hand: A proposal to vertically integrate by internal expansion (new construction). We are aware of no challenges by any competition agency to a proposal to vertically integrate by internal expansion, and the Memo cites none.[6] It is clear that there could be no antitrust challenge to the construction of a Producer-owned pipeline because there is no existing competition to be reduced – there is, as yet, no pipeline. Even if it were proper legal analysis to hypothesize an existing pipeline and subsequent acquisition by the Producers, no significant competition concerns would be presented, as explained below.

B. A Producer-Owned Pipeline Would Not Have Significant Incentives to Act in an Anticompetitive Manner Towards Third Party Shippers.

Greenberg Traurig alleges that the Producers would have the incentive to use the pipeline in anticompetitive ways in order to discriminate against rival third party shippers. This argument is necessarily based on the premise that the Producers have market power over natural gas prices in the lower 48 states, and therefore, have an incentive to restrict third party throughput, but that an independent, non-integrated pipeline owner would not. The Memo argues that the Producers would want to restrict third party throughput in order to maintain supra-competitive natural gas prices in the lower 48 States. The premise is demonstrably false, however, because the Producers do not have market power in any downstream market for the sale of natural gas. According to the Lukens Energy Group, the Producers' projected shares of natural gas sales in the lower 48 states in 2015 (when the pipeline comes on line) are: 7.9% for ExxonMobil, 7.3% for BP, and 5.8% for ConocoPhillips.

Because of their small shares of downstream natural gas sales, the Producers lack market power. Thus, any actions that the Producers might take to reduce their rivals' throughput on the Gas Pipeline would not affect the price of natural gas to customers in the lower 48 states. On the other hand, by restricting throughput from third party shipments, the Producers would forgo a return on those third party shipments as well as the ability to spread the fixed costs of the Gas Pipeline over greater volume.

Greenberg Traurig goes on to also argue, however, that the relevant market for antitrust purposes might not be the lower 48 states as a whole, but rather that relevant gas markets might be localized at certain locations – suggesting as possibilities both Chicago and other unidentified

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[6] In theory, the individual Producers could offer competing proposals to build the only pipeline, but no one has suggested that this loss of "engineering rivalry" is a concern.

[7] These are "equity shares," that is, shares of natural gas sales actually owned or under long term lease by the seller. Equity shares are the best measure for these purposes because brokers do not benefit from supra-competitive prices for gas owned by third parties.

Greenberg Traurig relies on higher shares calculated by attributing to the Producers sales they made as agents on behalf of other, third party owners (Memo at 3). It is not economically correct to inflate and then aggregate the shares of rivals in this way. Even when this incorrect approach is taken, the Memo barely elevates the market shares to the 35% threshold at which the DOJ and FTC Merger Guidelines recognize there may be an issue of market power for sellers of undifferentiated products, such as sellers of natural gas. *See* US Department of Justice and the Federal Trade Commission, Horizontal Merger Guidelines, § 2.22.

"Mid-Continent" areas. (Memo at 13). Even assuming that a local Chicago market for natural gas could be properly defined as a relevant market for antitrust analysis, the Producers would not have market power in that market.[8] For gas sold and transported on pipelines to the Chicago hub, the combined share of inbound pipeline capacity held by the North Slope Producers is less than 6% of the total, with BP being the largest with 3.13%.[9] Either individually or collectively, the market shares held by the Producers at pipeline hubs such as Chicago are simply too small to permit the exercise of market power.[10]

Even assuming – contrary to fact – that the Producers would have market power over the price of natural gas in the lower 48 states, or any smaller area, FERC regulations would constrain them from using their control of the pipeline to increase prices to natural gas customers. As will be discussed further in Part D below, FERC regulations prevent anticompetitive conduct by pipeline owners by requiring the Alaska gas pipeline to provide open and non-discriminatory access, tariffs, and services to all shippers, to increase capacity if demanded by shippers that genuinely need it, and to separate gas marketing from pipeline functions. Therefore, absent FERC's abdication of its regulatory power, which the Memo does not suggest would occur, the Producers could not use the pipeline in an anticompetitive manner, even if they wanted to do so.

C. The Producers Would Have the Same Incentive to Solicit Third Party Shippers to Ship on the Gas Pipeline as an Independent Owner.

Greenberg Traurig argues that a Producer-owned pipeline would not have the same incentives to increase throughput by third party shippers as an independent owner would. This is not correct. As owners of the Gas Pipeline, the Producers clearly would have an incentive to encourage third party shipments on the pipeline. By increasing throughput, the Producers will not only earn a return on the third party shipments, but also spread the fixed costs of pipeline operation over a greater amount of gas, thereby reducing shipping costs for the Producers' production affiliates. Increasing throughput increases efficiency, reduces average shipping costs, and, subject to any regulatory constraints, results in more profit to the owners. Because allowing

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[8] The proposed pipeline's gas could be routed to Chicago via Alberta.

[9] Because data on equity sales of gas at the Chicago hub is not available, we are using pipeline capacity shares calculated by the Lukens Energy Group as a proxy for equity sales shares. The market share of each of the Producers represents the ratio of firm capacity held by the Producer to the total contracted firm capacity for all of the pipelines transporting gas into the Chicago hub. Since the capacity may be used to transport remarketed gas, the capacity shares likely overstate the equity sales shares of the companies.

Pipeline capacity shares can also be meaningful in and of themselves. If the Producers attempted to restrict Alaska natural gas deliveries into the hub, there would be numerous competing owners of pipeline capacity serving that hub that could (and would) use their capacity to increase the supply of competing gas through the hub. Therefore, unless the Producers had such a significant share of the pipeline capacity at the hubs to "crowd out" virtually all competing sellers of gas, they would not have the ability to affect the price of gas at the hub.

[10] Greenberg Traurig identifies no other "Mid-Continent" hubs about which to be concerned. Because the volume of North Slope gas delivered at any downstream hub in the United States beyond Chicago would only diminish, there is no reason to believe the Producers would have a share "in other Mid-Continent areas" large enough to confer market power.

Even if we examine Producer shares further upstream from Chicago at Alberta, the shares are not significantly higher: According to the Lukens Energy Group, the combined Producer share of outbound pipeline capacity at Alberta is less than ten percent, with BP having 6.4%.

increased amounts of third party shipments is profitable to any pipeline owner – Producer or independent – the incentive to allow third party shipments is strong for both types of owners.

The Memo nevertheless constructs speculative theories of exclusionary conduct by the Producers. A necessary (but not sufficient) predicate for any theory of exclusionary conduct is that the pipeline owner(s) have significant market power in a relevant downstream market for natural gas. As noted in Part II.A above, the Producers have much too small a share of the owned (equity) natural gas in the lower 48 to affect price. But even if the Producers somehow acquired some ability to affect price in the lower 48 by reducing third party throughput, the increased profits from the higher gas prices hypothesized from such a strategy would have to (1) exceed the foregone profits from the throughput tariff revenues third parties would have paid, and (2) escape FERC detection and remedies under its open access regulations. Given the strong incentive to encourage third party shipments on the pipeline, there is no reason to believe the first condition would be met. As explained below, it is also unlikely that the second condition would be met.

D. The Gas Pipeline Act and the Open Season Regulations Ensure That a Producer-Owned Pipeline Would Not Have the Ability to Discriminate Against Rivals.

Greenberg Traurig relies heavily on the Attorney General's 1977 report to President Carter identifying potential competitive concerns relating to a producer-owned pipeline.[11] The report concluded that producer-ownership of the pipeline would create incentives to deny or impede future capacity expansion. Both the structure of the natural gas industry and the applicable regulatory regime have changed significantly since the 1977 report. FERC now requires that a company's transportation affiliate operate independently of the company's marketing affiliate. 18 C.F.R. § 358.4 (2005). Additionally, the FERC regulations require that the Alaska Gas Pipeline hold open seasons in order to provide all shippers an equal opportunity to bid for pipeline capacity. *See* Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects, 70 Fed. Reg. 8269 (Feb. 18, 2005), Order No. 2005, Docket No. RM05-1-000, (to be codified at 18 C.F.R. pt. 157) (the "Open Season Regulations").

The Gas Pipeline Act, the Open Season Regulations, and the FERC Standards of Conduct all contain provisions designed to prevent the owners of the Gas Pipeline from using the pipeline for anticompetitive purposes. The Open Season Regulations ensure that FERC can and will take action to preserve competition. In Order 2005, the Commission explained that it was "imposing strict requirements on all proposals . . . to ensure that there is a level playing field. As we discuss below, we will require applicants for an Alaska pipeline project to provide detailed information as to project design, how capacity is to be allocated, and proposed rates, terms and conditions. This will allow us to be in a position to monitor whether competition for capacity is fair." 110 FERC ¶ 61,095 at Paragraph 12 (2005).

Even assuming that the Producers had market power downstream, the application process at FERC for a certificate of public convenience and necessity would alleviate concerns that the

[11] The end result of that report was a condition in President Carter's Decision prohibiting the producers from equity ownership. This proved unworkable and the condition was removed in 1981.

Producers would build a purposefully undersized Gas Pipeline in order to prevent third party shippers from competing with them in the downstream market for the sale of gas. In considering any certificate application, "the Commission will consider the extent to which a proposed project has been designed to accommodate the needs of shippers who have made conforming bids during open season, as well as the extent to which the project can accommodate low-cost expansion, and may require changes in project design necessary to promote competition and offer a reasonable opportunity for access to the project." 18 C.F.R. § 157.37 (2005). Moreover, the Open Season Regulations and Order 2005 demonstrate that the Commission will enforce its requirements that a Gas Pipeline be designed in order to accommodate all shippers who make genuine bids for capacity. Furthermore, a third party shipper can bring a complaint at the Commission about the Producers' proposal if the shipper believes that the Producers are proposing to build a Gas Pipeline that has insufficient capacity, and it may seek Commission action to address its concern.

Even after the construction of Gas Pipeline, there should not be any substantial concern that the Producer-owners of the Gas Pipeline have the ability to "crowd out" third party shippers or refuse to expand the capacity of the Gas Pipeline for anticompetitive reasons. Section 105(a) of the Gas Pipeline Act gives FERC the authority to "order the expansion of the Alaska natural gas project if the Commission determines that such expansion is required by the present and future public convenience and necessity." Consequently, if a third party shipper believes that the Gas Pipeline has impermissibly refused to increase its capacity, it can seek relief from the Commission.

Moreover, the Natural Gas Act's nondiscrimination provisions and the Standards of Conduct regulations would preclude efforts by the Producers to favor their shipping affiliates to the detriment of third party shippers. Under the Natural Gas Act, a gas pipeline may not grant any "undue preference or advantage" to any shipper, subject any shipper to "undue prejudice or disadvantage," or "maintain any unreasonable differences in rates, charges, service, facilities or in any other respect." 15 U.S.C. § 717c (b). Similarly, under FERC's Standards of Conduct, a gas pipeline "must treat all transmission customers, affiliated and non-affiliated, on a nondiscriminatory basis, and must not operate its transmission system to preferentially benefit an Energy Affiliate." 18 C.F.R. § 358.2(b). Consequently, the Producer-owners can not discriminate in favor of their own production (shipping) affiliates in order to give them a competitive advantage over a third party shipper.

III. The Potential Remedies Proposed by Greenberg Traurig Are Neither Likely Nor Feasible.

Despite the lack of a tangible antitrust concern, and the presence of extensive open access regulation by FERC, regulations, the Memo maintains that there is a chance that FERC would choose to go beyond its comprehensive regulations and impose additional remedies on a Producer-owned Gas Pipeline. Based on this possibility, the Memo asserts that a Producer-owned pipeline would face burdensome and time-consuming regulatory hurdles that an

independent pipeline could avoid.[12] The Memo asserts that potential remedies include divestiture, establishment of an independent system operator, or imposition of a market monitor. However, given the existence of pervasive agency regulation, the probability that remedies such as these would be instituted by either the FERC or the FTC is extremely low. With respect to potential FTC action, Greenberg Traurig cites no support for the proposition that vertical integration through internal expansion would raise antitrust concerns at the FTC. The Memo instead offers three FTC cases (at 8) in support of its conclusions. None of these FTC cases, however, involved situations where the parties had vertically integrated through internal expansion, and are therefore not instructive here.

Greenberg Traurig suggests that the Producers may be required to sever their relationships with both their upstream and downstream affiliates through some sort of divestiture, resulting in an entity that only holds the ownership of the pipeline (even though the initial funding and personnel for the entity would come from the Producers). In support of this position, the Memo argues that the FTC has used this divestiture method in the past. However, the Memo fails to cite any case in the entire energy sector to support its contention that the FTC would act in such a manner. In addition, the Memo does not sufficiently explain why divestiture is a preferable remedy compared to the FERC regulation that would otherwise control the pipeline. Moreover, it is unlikely that the FERC would conclude that the regulatory structure it has used to ensure access to gas pipelines in the lower 48 is insufficient to protect shippers for the Gas Pipeline.

The other remedies suggested by the Memo are even more implausible. While establishing an independent system operator or a market monitor may well address third party shippers' fears of potential anticompetitive Producer-owner conduct, FERC has never required a natural gas pipeline to transfer control of its facilities to an independent operator – a point conceded by Greenberg Traurig. Moreover, the Memo fails to explain why such a radical remedy is necessary or desirable, or and why conventional regulation is insufficient to keep the Producer-owners' conduct under control.

In conclusion, based on the facts we know today, it is highly unlikely that the Federal Energy Regulatory Commission would deny a certificate of public convenience and necessity to a Producer-owned Gas Pipeline based on the competitive issues raised by Greenberg Traurig. Existing antitrust law and FERC regulation are sufficient to prevent and address any competitive issues that may arise.

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[12] The Memo argues that there is a significant risk of a delay of the certificate application process at FERC due to potential third party complaints against a producer-owned pipeline, and that such a risk of delay would not exist if the application were submitted by an independent pipeline owner. However, the Memo neglects to consider that Sections 103 and 104 of the Alaska Natural Gas Pipeline Act of 2004 place a twenty month total time limit on the issuance of a certificate at FERC; the Commission must issue (or decline to issue) a certificate no later than 60 days after the issuance of a final environmental impact statement. *See* ANGPA § 103(c) and § 104(d). Therefore, Minesinger and Chung's argument that protests over competitive issues would necessarily delay the issuance of a certificate misses a key fact.